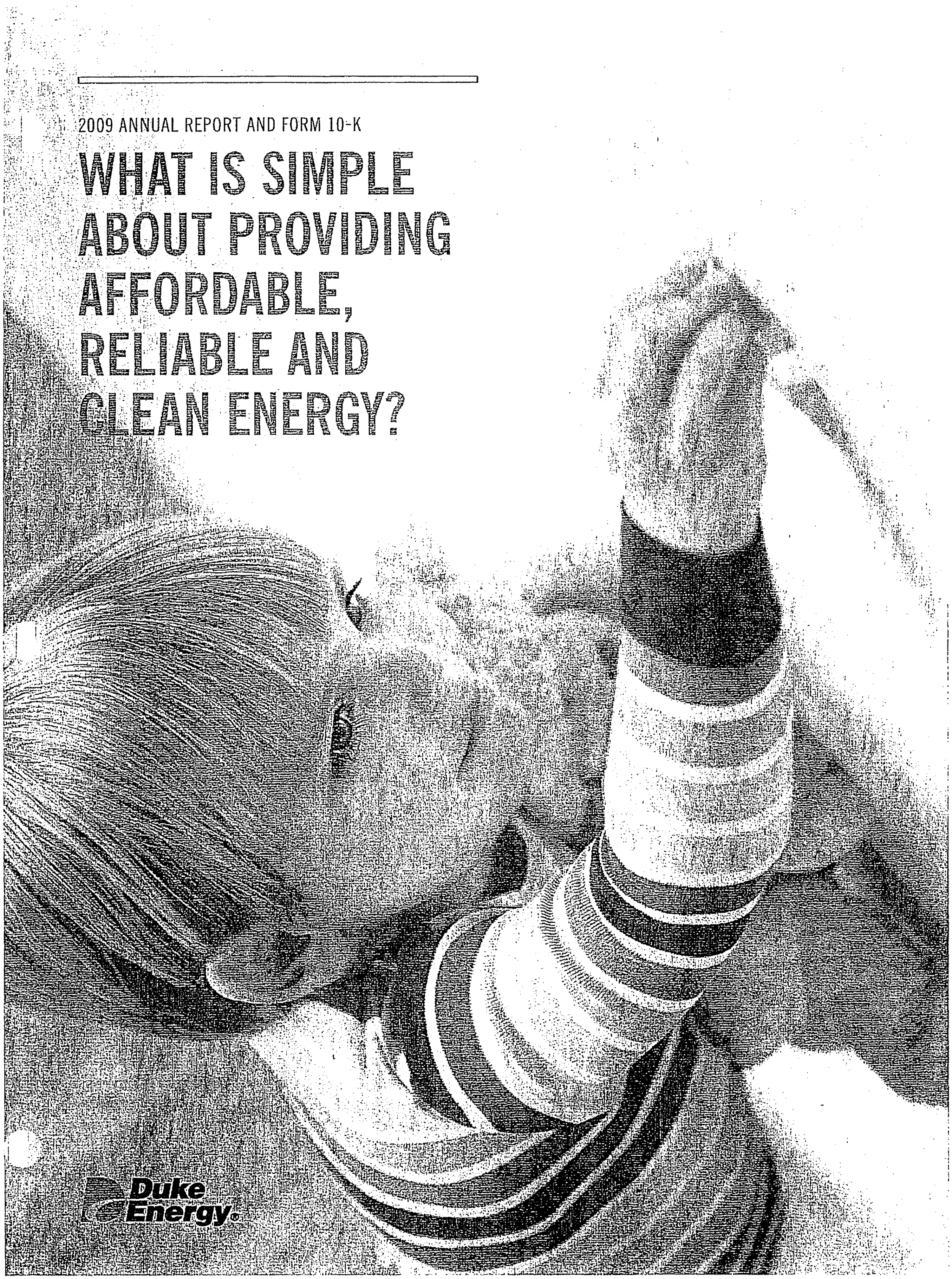
JOINT APPLICANTS
EXHIBIT A
PAGE 001

2009 ANNUAL REPORT AND FORM 10-K

WHAT IS SIMPLE ABOUT PROVIDING AFFORDABLE, RELIABLE AND CLEAN ENERGY?



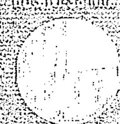
CONTENTS

PROFILE

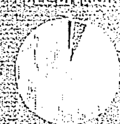
Duke Energy is one of the largest electric power holding companies in the United States. Our regulated utility operations serve approximately 4 million customers located in five states in the Southeast and Midwest, representing a population of approximately 11 million people. Our commercial power and international business segments own and operate diverse power generation assets in North America and Latin America, including a growing portfolio of renewable energy assets in the United States.

2010 ADJUSTED SEGMENT EBIT

BUSINESS MIX DIVERSITY



FUEL DIVERSITY



WHAT IS SIMPLE ABOUT PROVIDING AFFORDABLE, RELIABLE AND CLEAN ENERGY?

Not much! Providing energy around the clock is more complicated than just flipping a switch. We must manage complex trade-offs. For instance, investing in fossil fuels to produce electricity is desired by some because they are affordable and reliable, but they also produce environmental emissions. Renewable fuels have little or no emissions, but they also are not yet as affordable or reliable as fossil fuels. Additionally, we must balance customer needs for affordable, reliable and cleaner energy with investor needs for competitive returns on their invested capital. In this year's report, we will show you how we balance these trade-offs to generate sustainable growth that benefits all of our stakeholders.

JOINT APPLICANTS
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OUR STRATEGIC FOCUS FOLDOUT

OUR STRATEGIC FOCUS – 2010 AND BEYOND
AFFORDABLE, RELIABLE AND CLEAN ENERGY MANDATE

These two pages illustrate how we provide our customers with energy that is affordable, reliable and clean. You can see our strategies for modernizing our regulated facilities and for maximizing diverse earnings from our commercial businesses, which lead to enhanced financial strength.

STRATEGIC FOCUS

Regulated Operations

ACTIONS

- Retire and replace older fossil generating units with new, cleaner-coal, lower-emitting gas units and renewable energy to meet future peak demand
- Replace analog grid with a digital smart grid to increase reliability and energy efficiency, and to reduce costs

- Maintain the high reliability of our generation fleet and distribution system
- Improve customer satisfaction
- Aggressively manage costs

- Achieve timely and constructive recovery of investments, and close the gap between allowed and earned returns
- Leverage energy efficiency framework that allows us to earn returns on energy efficiency investments, reducing the need for new power plants
- Achieve workable federal legislation to regulate carbon emissions

2009 and Early 2010 Progress

- Achieved nonfuel base-rate increase settlements in North Carolina, South Carolina, Ohio and Kentucky
- Energy efficiency framework approved in Ohio, North Carolina, South Carolina and Indiana
- Deploying smart grid in Ohio in early 2010

Commercial Businesses

- Use Duke Energy Retail Sales defensively and offensively to mitigate impact of customer switching in Ohio
- Continue to optimize Midwest coal and gas generation assets in the wholesale market

- Bring approximately 250 megawatts (MW) of wind energy on line each year
- Expand into solar and biomass energy
- Achieve and utilize federal and state tax incentives

- Maintain earnings diversity and steady cash flows
- Grow these businesses by investing in projects that fit our business model and our return expectations

2009 and Early 2010 Progress

- Retained margin in Ohio with retail customer strategy
- Added more than 360 MW of wind energy in 2009, and ended the year with approximately 735 MW of wind power in commercial operation in three states
- Acquired first solar project in early 2010

Financial Strength

- Deploy capital to maintain an approximately 75 percent regulated, 25 percent commercial business mix
- Achieve appropriate risk-adjusted returns in our commercial businesses

- Issue $400 million in equity in 2010 from dividend reinvestment plan (DRIP) and other internal plans
- Maintain current investment-grade credit ratings
- Maintain strong liquidity

- Achieve a long-term adjusted diluted earnings per share (EPS) compound annual growth rate of 4 to 6 percent off a base of 2009 adjusted diluted EPS of $1.22
- Achieve 2010 adjusted diluted EPS of $1.25 to $1.30
- Grow dividend at a rate slower than the growth in adjusted diluted EPS

2009 and Early 2010 Progress

- Grew dividend approximately 4 percent in 2009
- Issued $3.75 billion of fixed-rate debt at an average rate of 5.2 percent during 2009
- Since 2008, issued more than $7 billion of fixed-rate debt at attractive rates and terms, and issued $600 million in equity through DRIP and other internal plans

FINANCIAL HIGHLIGHTS[a,b]

(In millions, except per-share amounts)	2009	2008	2007	2006	2005
Statement of Operations					
Total operating revenues	$12,731	$13,207	$12,720	$10,607	$6,906
Total operating expenses	10,518	10,765	10,222	9,210	5,586
Gains on sales of investments in commercial and multi-family real estate	—	—	—	201	191
Gains (losses) on sales of other assets and other, net	36	69	(5)	223	(55)
Operating income	2,249	2,511	2,493	1,821	1,456
Total other income and expenses	333	121	428	354	217
Interest expense	751	741	685	632	381
Income from continuing operations before income taxes	1,831	1,891	2,236	1,543	1,292
Income tax expense from continuing operations	758	616	712	450	375
Income from continuing operations	1,073	1,275	1,524	1,093	917
Income (loss) from discontinued operations, net of tax	12	16	(22)	783	935
Income before cumulative effect of change in accounting principle and extraordinary items	1,085	1,291	1,502	1,876	1,852
Cumulative effect of change in accounting principle, net of tax and noncontrolling interest	—	—	—	—	(4)
Extraordinary items, net of tax	—	67	—	—	—
Net income	1,085	1,358	1,502	1,876	1,848
Dividends and premiums on redemption of preferred and preference stock	—	—	—	—	12
Net income (loss) attributable to noncontrolling interests	10	(4)	2	13	24
Net income attributable to Duke Energy Corporation	$ 1,075	$ 1,362	$ 1,500	$ 1,863	$ 1,812
Ratio of Earnings to Fixed Charges	3.0	3.4	3.7	2.6	2.4
Common Stock Data					
Shares of common stock outstanding [c]					
Year-end	1,309	1,272	1,262	1,257	928
Weighted average—basic	1,293	1,265	1,260	1,170	934
Weighted average—diluted	1,294	1,267	1,265	1,188	970
Income from continuing operations attributable to Duke Energy Corporation common shareholders					
Basic	$ 0.82	$ 1.01	$ 1.21	$ 0.92	$ 0.94
Diluted	0.82	1.01	1.20	0.91	0.92
Income (loss) from discontinued operations attributable to Duke Energy Corporation common shareholders					
Basic	$ 0.01	$ 0.02	$ (0.02)	$ 0.67	$ 1.00
Diluted	0.01	0.01	(0.02)	0.66	0.96
Earnings per share (before cumulative effect of change in accounting principle and extraordinary items)					
Basic	$ 0.83	$ 1.03	$ 1.19	$ 1.59	$ 1.94
Diluted	0.83	1.02	1.18	1.57	1.88
Earnings per share (from extraordinary items)					
Basic	$ —	$ 0.05	$ —	$ —	$ —
Diluted	—	0.05	—	—	—
Net income attributable to Duke Energy Corporation common shareholders					
Basic	$ 0.83	$ 1.08	$ 1.19	$ 1.59	$ 1.94
Diluted	0.83	1.07	1.18	1.57	1.88
Dividends per share [d]	0.94	0.90	0.86	1.26	1.17
Balance Sheet					
Total assets	$57,040	$53,077	$49,686	$68,700	$54,723
Long-term debt including capital leases, less current maturities	$16,113	$13,250	$ 9,498	$18,118	$14,547

(a) Significant transactions reflected in the results above include: 2009 impairment of goodwill and other assets (see Note 11 to the Consolidated Financial Statements, "Goodwill and Intangible Assets"), 2007 spinoff of the natural gas businesses (see Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies"), 2006 merger with Cinergy, 2006 Crescent joint venture transaction and subsequent deconsolidation effective Sept. 7, 2006, 2005 DENA disposition, 2005 deconsolidation of DCP Midstream effective July 1, 2005, and 2005 Duke Energy Field Services, LLC (DEFS) sale of Texas Eastern Products Pipeline Company, LLC (TEPPCO).

(b) Periods prior to 2009 have been recast to reflect the adoption of the noncontrolling interest presentation provisions of Accounting Standards Codification 810 – Consolidation, which was adopted by Duke Energy effective Jan. 1, 2009.

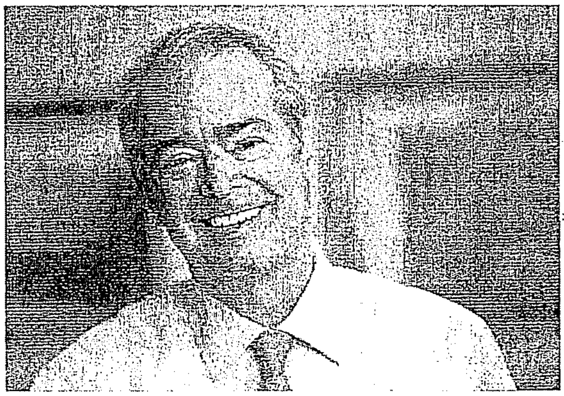
(c) 2006 increase primarily attributable to issuance of approximately 313 million shares in connection with Duke Energy's merger with Cinergy.

(d) 2007 decrease due to the spinoff of the natural gas businesses to shareholders on Jan. 2, 2007, as dividends subsequent to the spinoff were split proportionately between Duke Energy and Spectra Energy, such that the sum of the dividends of the two stand-alone companies approximated the former total dividend of Duke Energy prior to the spinoff.

See Notes to Consolidated Financial Statements in Duke Energy's 2009 Form 10-K.

CHAIRMAN'S LETTER

TO STAKEHOLDERS



JAMES E. ROGERS
Chairman, President and
Chief Executive Officer

Dear fellow investors, customers, employees and all others who have a vested interest in our success — including our partners, suppliers, policymakers, regulators and communities:

Flipping a light switch is simple. Our mission of providing our customers with affordable, reliable and cleaner energy, 24/7, is not.

Our industry is capital-intensive. Our assets are built to last for decades to meet the long-term needs of our customers. We must make billion-dollar investment decisions today to build large-scale plants that will operate half a century or more. Today's uncertainties around new environmental regulations and climate change legislation make these decisions even more difficult.

We expect Congress or the U.S. Environmental Protection Agency (EPA) to regulate carbon emissions as early as 2011. We also expect an onslaught of new environmental regulations on coal — not only for carbon emissions, but also for hazardous air pollutants, ash ponds, the production of coal from mountaintop removal and water discharge. These new rules could require us to retrofit or retire thousands of megawatts (MW) of coal-fired generation, beyond what we were already planning.

We make the best decisions when we listen carefully to our stakeholders, bring our expertise to bear on critical political, economic and environmental issues, and stay focused on our mission. Engaging constructively in a dialogue will help protect the interests of both our customers and our investors.

A BALANCING ACT

We must act today to ensure an affordable, reliable and cleaner supply of energy for our customers in the future. Between 2010 and 2012, we expect to invest between $14 billion and $15 billion to modernize our aging regulated generation, transmission and distribution system, maintain our existing facilities, and sustain earnings and cash flow from our commercial businesses. As we work to achieve constructive regulatory recovery of our investments and earn fair returns on capital, we will strive to smooth out and reduce the impact of future rate increases on our customers.

Our strategies are clear:

- Modernize our facilities to repower the regions we serve, improve reliability, create new jobs and reduce our environmental impact.
- Execute on a new regulatory model for energy efficiency to help our customers save money and make the communities we serve more energy efficient.
- Keep our commercial businesses profitable and focused on earning solid economic returns.
- Engage on the front lines of the climate change, energy and environmental debates to help protect the interests of our stakeholders, especially our customers and investors.

The table on pages 2 and 3 of this report summarizes our strategic initiatives, which I discuss in greater detail below. Some of these are early-stage initiatives designed to create options, such as our ongoing efforts to expand energy efficiency. Some remain central to our strategy regardless of what happens, such as modernizing our generation fleet and our grid, and expanding our renewable energy portfolio.

Finally, other initiatives, such as our proposed nuclear plant projects, have a longer time frame. To succeed in these efforts, we must be alert to changes that may require course adjustments.

2009 RESULTS

Last year was difficult for both our customers and our industry. On a weather-normalized basis, our customers' demand for power was down approximately 4 percent, primarily due to declines in manufacturing load. Cooler summers in both the Midwest and the Southeast also reduced electricity demand.

We can't control the economy or the weather, so throughout the year, we focused on what we could control. We aggressively managed our costs — reducing our planned operating and maintenance expenses by more than $150 million, exceeding our $100 million target.

Our regulated operations also maintained high operational performance. Our nuclear fleet had one of the best years in its history, and our fossil plants had their best year for availability and reliability in 10 years.

Our commercial businesses include our growing renewable energy portfolio, our international assets in Latin America, our competitive fossil generation and retail sales business in Ohio, and our natural gas generation in the Midwest. Last year, in total, our commercial businesses increased both earnings and cash flows.

In our renewables business, we added just over 360 MW of wind power and ended 2009 with approximately 735 MW in commercial operation. In Latin America, our 4,000 MW of highly contracted hydroelectric and gas plants generated strong cash flows and earnings.

In Ohio, the recession drove down wholesale power prices, and competitors set out to undercut our locked-in rates. We met this challenge by launching a strategy to attract customers seeking competitive suppliers with our own competitive retail supplier, Duke Energy Retail Sales. As you would expect, this required us to reduce our margins in order to retain some of our customers. In 2010, we will continue our efforts to mitigate customer switching, as well as position and maximize the value of our Ohio and Midwest businesses in the wholesale generation market.

With our sizable investments to modernize our energy infrastructure, capital is our lifeblood. Thanks to our strong balance sheet, we had remarkable access to the capital markets. We issued $3.75 billion of fixed-rate debt at an average 5.2 percent interest rate in 2009. Over the past two years, we issued more than $7 billion of fixed-rate debt at favorable rates and terms, and $600 million of equity through our dividend reinvestment plan (DRIP) and other internal plans. At year-end, our debt to total capitalization ratio was 44 percent, and we maintained our investment-grade corporate credit ratings.

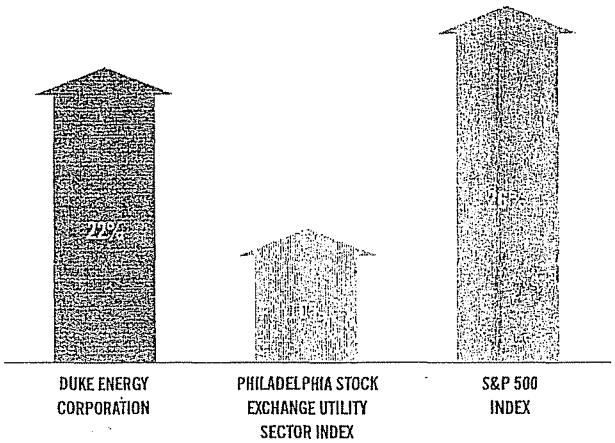
Due to our employees' extraordinary efforts last year, we exceeded our 2009 employee incentive target by 2 cents, earning $1.22 per share on an adjusted diluted basis. Reported diluted earnings per share (EPS) were 83 cents for 2009.

Our total shareholder return — the change in stock price plus dividends — was up 22 percent for the year. That compares favorably with the Philadelphia Utility Index (made up of 20 peer companies, including Duke Energy), which was up only 10 percent in 2009. Over the past three years, Duke Energy has achieved a positive 4 percent shareholder return, while the utility index dropped nearly 5 percent.

Even though our adjusted earnings have been essentially flat over the last three years, we grew our dividend an average of approximately 4 percent each year during this period.

The one area where we didn't meet expectations is employee and contractor safety. After a fatality-free 2008, we suffered three contractor deaths in 2009. This reminds us of the hazards involved in bringing energy to millions of

COMPARISON OF 2009 TOTAL SHAREHOLDER RETURN
(12 months ended Dec. 31, 2009)



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people. Even though our injury rate trended to the lowest it's ever been, any injuries or fatalities are unacceptable. I have challenged all of our employees and contractors to redouble their efforts in this area.

For the fourth year in a row, Duke Energy was named to the Dow Jones Sustainability Index for North American companies in the electric utility sector. Early in 2010, *Corporate Knights* magazine named us one of the 100 most sustainable companies in the world. And, in March 2010, we were named one of the 100 Best Corporate Citizens for the second consecutive year by *Corporate Responsibility (CR)* magazine.

I invite you to review our 2009|2010 Sustainability Report, available on www.duke-energy.com, to learn more about our commitment to do business in ways that are good for people, the planet and profits.

2010 OUTLOOK

In the latter half of 2009, it seemed that the economy might be stabilizing. However, with double-digit unemployment in several of our jurisdictions, we expect economic growth for the next few years to be anemic. Our 2009 year-end results and our current economic projections lead us to a 2010 earnings outlook range of $1.25 to $1.30 EPS on an adjusted diluted basis. This range puts us on track to grow long-term adjusted diluted EPS at a compound annual growth rate of 4 to 6 percent, from a 2009 base year.

In 2010, we will need to fund about $3.5 billion to complete our construction programs and address the negative cash flow impacts of the ongoing economic downturn. Externally, we expect to issue approximately $2.3 billion in new debt securities and raise approximately $400 million of new equity through our DRIP and other internal stock plans. The remainder will come from the utilization of cash we realized from prefunding some of our 2010 financing needs in 2009. The equity we plan to issue will help maintain our strong balance sheet.

We are committed to growing the dividend, but at a slower rate than our growth in earnings. Over time, our payout ratio will trend downward to levels more consistent with our industry peers. Subject to board approval, we estimate a 2 percent dividend increase in 2010.

IS THE ENERGY WE PROVIDE AFFORDABLE?

The first question we ask when we consider making a long-term investment to achieve our mission is: *Will it provide affordable energy for our customers?* Given our long lead times for construction, we must consider both present and future affordability.

We are investing today in more efficient coal-fired plants and other technologies to maintain the fuel flexibility of our generation fleet. This will help to mitigate the impact of future price spikes for any one fuel, and smooth out customer bills. Replacing some of our oldest coal-fired plants with new, efficient and lower-emitting coal units makes economic sense because of our nation's vast supply of affordable and reliable coal.

Our 825-MW Cliffside advanced coal project in North Carolina is about 55 percent complete. We call this a "bridge plant" because when the new advanced-technology generating unit is finished in 2012, it will begin to replace a total of 1,000 MW of older, higher-emitting coal units, which we will retire from service.

In Indiana, our 630-MW Edwardsport integrated gasification combined-cycle plant is about 50 percent complete. This is one of the cleanest, largest and most advanced coal gasification projects in the world. When completed in 2012, it will replace 160 MW of older and higher-emitting generation that is more than half a century old. We are investing $17 million to study carbon capture at the site. We are also proposing to spend $42 million for the first phase of site selection and characterization studies for the permanent underground storage of up to 60 percent of the plant's carbon dioxide (CO_2) emissions.

Additionally, we are building two very efficient 620-MW combined-cycle natural gas-fired plants at two existing coal-fired power plant sites in North Carolina. When completed in 2011 and 2012, these cleaner-burning units will leverage our ability to use growing supplies of domestic natural gas. They will also enable the retirement of about 250 MW of older coal-fired units as part of the 1,000 MW referenced above.

Another component of our modernization strategy includes investments in a more efficient electric grid to improve future reliability and to promote end-use energy efficiency. I will discuss more about that below.

Constructive capital recovery

As a regulated utility, our only vehicle for earning on our plant and grid investments is the recovery of capital and earning a return on equity that regulators allow through our electric rates. The rate settlements we reached last year with nearly all of the parties in four of our five jurisdictions are prime examples of our work to achieve constructive regulatory outcomes for our customers and investors alike. We also successfully continued the ongoing construction work in progress (CWIP) recovery of financing costs for our Edwardsport cleaner-coal project in Indiana.

Given the state of the economy, it's not easy asking for rate increases. But keep in mind, in the Carolinas alone, we have not raised our nonfuel base rates in those states since 1991, and our rates remain competitive for our customers and for the communities we serve. For instance, in North Carolina, if our rates had kept up with inflation, our 1991 residential base rate of 7.1 cents per kilowatt-hour (kWh) would be nearly 11.2 cents per kWh today. With the recently approved rate increase, the average residential customer will pay about 9.2 cents per kWh, well below the national average of nearly 11.8 cents per kWh for residential customers.

To be able to provide customers with affordable power, we must seek and obtain constructive regulatory solutions in all five of our state jurisdictions. As we are granted timely recovery of our construction costs and expenses, and fair returns on our equity capital, we will be able to raise new capital at competitive and fair costs. Our regulatory framework to expand energy efficiency will also help to reduce energy costs, while earning fair returns for our investors.

New partnerships to advance affordable power

To accelerate the development of cleaner and more affordable coal technologies, we are sharing research and experience with U.S. partners, such as the Electric Power Research Institute (EPRI), an independent, nonprofit organization of scientists, engineers and other electricity experts from around the world.

Last year, we entered into agreements with China's Huaneng Group and ENN Group, two of the nation's largest energy providers. We will work jointly to develop an array of clean energy technologies, not only carbon capture and storage, but also renewable energy, smart grid and battery storage. Like the United States, China has enormous coal reserves and huge potential for the permanent underground storage of CO_2. These ventures, along with our EPRI collaboration, will allow us to scale up and commercialize new technologies more rapidly, and at less cost.

Nuclear is the only baseload generation that has zero greenhouse gas emissions. We continue to pursue plans, including potential regional partnerships, to develop a new 2,234-MW nuclear power plant, the William States Lee III Nuclear Station, in Cherokee County, S.C. If approved, the plant could come on line in the 2021 time frame.

Bringing new nuclear energy capacity to the Midwest will help diversify that region's dependence on coal. Last year, we created the Southern Ohio Clean Energy Park Alliance to explore development of a nuclear power plant at a U.S. Department of Energy site in southern Ohio.

Both nuclear ventures will help us achieve important economic and policy goals, and maintain our strategic flexibility. However, we will proceed with these projects only if we can be assured of constructive rules that allow us to recover our costs and earn fair returns.

IS THE ENERGY WE PROVIDE RELIABLE?

The next question we ask in meeting our mission is: *Will the investments we make deliver reliable energy?* Reliability depends on how electricity is delivered. Modernizing our transmission and distribution grid is key to improving reliability. That's why we plan to invest up to $1 billion over five years to begin the conversion of our power delivery system into an advanced, state-of-the-art "smart grid."

Smart grid benefits

A smarter grid will create a digital, two-way information exchange between us and our customers. It will transform today's century-old power delivery system into an advanced energy network that delivers electricity and energy usage information.

Today's analog meters give us just 12 data points per year — the after-the-fact monthly usage, which generates the monthly bill. Smart meters will provide us and our customers more than 9,000 data points every year. Armed with this new information, we will be able to make more accurate load forecasts and reduce our costs by better balancing supply and demand. But that's only the beginning of the story.

Because smart meters will send information back to us, we'll know sooner when and where power outages occur. We'll be able to remotely identify trouble spots and restore service faster. In some cases, power outages will be avoided altogether due to the smart grid's "self healing" capability. Intelligent sensors and switches will automatically identify, isolate and "cure" power line problems. Today, we know that service is disrupted only when a customer calls to report the outage.

STRATEGIC FOCUS **REGULATED OPERATIONS**

Q: How will your modernization strategy lead to revenue and earnings growth?

A: This strategy is based on investing capital today to replace older, inefficient and higher-emitting fossil generating plants, and to build a smarter grid to help us prepare for a lower-carbon, cleaner-energy future. This prudent investment of capital will increase our rate base and, with constructive regulation, it will lead to revenue and earnings growth.

Q: Why are you investing significant capital in new power plants when load growth has fallen?
A: We build plants to meet the long-term needs of our customers. Although the recessionary economy has impacted our near-term load, we must prepare for the future when demand growth returns. Regardless of the recession, we will need additional capacity to meet our peak demand in the future. In both the Carolinas and the Midwest, we have not built a new baseload power plant since the 1980s. The new cleaner-coal and gas-fired generating units we are building will replace the older fossil plants we anticipate retiring over the next decade.

Q: How do you intend to achieve constructive regulatory outcomes?
A: We have a track record of recovering our investments through regulatory proceedings with an approach that balances the needs of all of our stakeholders — and involves all parties in negotiations to reach constructive settlements. Our current focus is to build support for closing the gap between the time we invest and the time it takes to recover our investment.

Q: Why is operational excellence significant for meeting financial goals?
A: Operating our plants and system with high availability and efficiency, while also providing excellent service at affordable rates, is necessary to build customer satisfaction and regulatory support. Our commitment to operational excellence demonstrates our discipline in allocating capital to achieve top-tier performance.

Q: Are you identifying other revenues beyond your traditional business?
A: We are working to grow revenues outside the traditional electric sales business. These new sources include energy efficiency products and services, wholesale origination (supplying power to rural electric co-ops and municipalities) and our economic development efforts.

Our smart grid is also critical for meeting the power needs of plug-in hybrid electric and all-electric vehicles. To better understand these game-changing technologies, we are joining FPL Group to invest a combined $600 million with the goal that 100 percent of all new fleet vehicles purchased will be plug-in electric vehicles or plug-in hybrid electric vehicles by 2020. We also foresee great potential for job creation, as our nation builds the new recharging infrastructure for these vehicles.

Through the end of 2009, we had invested approximately $90 million to deploy limited-scale smart grid projects. We continue to pursue smart grid deployments in North Carolina, South Carolina, Kentucky and Indiana. In December 2008, we received approval from the Public Utilities Commission of Ohio to move forward with full-scale deployment. After conducting successful pilot programs in 2009, we expect to install 140,000 smart electric and gas meters and other associated technologies in 2010. Our Ohio deployment will grow to more than 1 million smart meters and other components installed over the next five years. We are recovering these investments through an annual rate tracker in Ohio.

In 2009, the U.S. Department of Energy (DOE) awarded us $200 million under the American Recovery and Reinvestment Act to support our smart grid projects in the Midwest, and another $4 million toward our smart grid efforts in the Carolinas. We continue to work with the DOE on finalizing the terms of the grant contract.

STRATEGIC FOCUS: COMMERCIAL BUSINESSES

Q: What is the value proposition for your commercial businesses, and how do they grow earnings and cash flow?

A: Our commercial businesses consist of: Midwest Generation, Renewables and Duke Energy International (DEI). Combined, these businesses provide diverse geographic, technological and fuel-sourcing advantages. This diversity is key to generating strong cash flows and earnings.

Q: What is the Midwest Generation strategy?

A: Midwest Generation includes about 4,000 megawatts (MW) of predominantly coal-fired generation plants that currently are dedicated to Duke Energy Ohio customers, and about 3,600 MW of gas-fired plants located in Ohio and other Midwestern states that serve wholesale markets. This is a mature business that has historically provided good cash flows and earnings.

In Ohio, generation is deregulated, which allows retail customers to switch to alternative suppliers. In 2009, we mitigated this threat by launching a strategy to attract customers through our own retail supplier. We expect this business to continue focusing on producing strong cash flows and solid returns. We don't anticipate investing growth capital in this business over the next several years, and we'll carefully manage our operating and maintenance expenses.

Q: What is the Renewables strategy?

A: We launched our Renewables business in 2007 with investments in wind energy. We now have approximately 735 MW of operating wind projects in Texas, Wyoming and Pennsylvania, and we expect to have nearly 1,000 MW of commercial wind power in operation by the end of 2010. Over the past two years, we have created solar photovoltaic, biomass and commercial transmission businesses. Like our wind business, the output from these projects will be highly contracted with creditworthy partners. Near-term growth in renewables will be driven by favorable federal and state public policy, including renewable portfolio standards and tax credits.

Q: What is the International strategy?

A: DEI consists of predominantly hydroelectric generation assets in Brazil, and a combination of hydro and fossil generation in Peru and other Latin American countries. DEI provides diverse and consistent earnings growth. Our strategy is to reinvest internally generated capital into growth projects that fit our business model and meet our return expectations.

Energy efficiency: A business model for the 21st century

The smart grid will become an important enabler for more efficient energy use. It complements our goal to level the playing field between incentives in place to promote new plants and incentives needed to promote energy efficiency investments. Most utilities today continue to operate under regulatory frameworks created decades ago that reward them for building new power plants and distribution systems. They lack incentives to invest in end-use energy efficiency.

Our energy efficiency plan takes steps toward creating a framework that will allow us to earn a return on the costs of new construction that we avoid due to the expansion of end-use efficiency innovations. Over time, the growth in energy efficiency programs is expected to smooth out the demand for energy, making our demand less "peaky" (less generation needed to meet peak loads). As a result, customers' overall energy costs would be reduced. The cost of these programs will be recovered through a nominal energy efficiency rate rider included in the monthly energy bill.

First approved in Ohio in December 2008, our energy efficiency framework was approved last year in North Carolina, and in early 2010 in South Carolina and Indiana. In Kentucky, we are evaluating a filing in late 2010.

IS THE ENERGY WE PROVIDE CLEAN?

Finally, to realize our mission we ask: *Will the investments we make provide cleaner energy?*

Cleaner energy includes our investments in new, more efficient and lower-emitting coal- and gas-fired power plants, as well as the approximately $5 billion we have invested over the last decade to significantly reduce sulfur dioxide and nitrogen oxide emissions from our existing coal fleet. We are also making significant investments in renewable energy in both our regulated and commercial businesses.

Including our renewables investments, our nuclear fleet in the Carolinas and our hydroelectric assets in North America and South America, we are now the third largest producer of carbon-free electricity in the Americas among U.S.-based, investor-owned utilities.

And we continue to reduce our carbon intensity, which is the amount of CO_2 emitted per unit of electricity produced. Based on the latest available 2008 data, of the 20 largest U.S.-based, investor-owned utilities, we rank 10th in carbon intensity. In 2007, we ranked ninth.

Regulated renewables portfolio

Investing in renewable energy diversifies our fuel mix and reduces our carbon footprint. In 2009, we were active on many fronts to increase our renewable power portfolio.

To gain experience with the design, construction and maintenance of distributed solar generation on our system, last year we received approval from the North Carolina Utilities Commission to construct solar power systems on multiple customer properties. We brought our first system under this program on line in early 2010 — a 1-MW system with more than 5,200 solar panels on the roof of a large manufacturing facility in North Carolina. We are on track to construct a total of 8 MW of solar power systems by the end of 2010. That is enough generating capacity to power about 1,300 average-sized homes annually.

Last year, North Carolina's policymakers put incentives in place to support the creation of a state offshore wind industry. As a result, we announced plans to construct up to three offshore wind turbines to be sited in state waters inside North Carolina's Outer Banks. We are partnering with the University of North Carolina on this initiative, which could be the first wind turbines operating offshore in the United States.

In addition to the direct investments we are making to own solar and wind power in our regulated business, we are also exploring blending wood chips with coal as a supplemental fuel source that could reduce coal usage at our existing power plants. We have conducted successful trials of this process, known as biomass cofiring, and we are developing plans to make it a major part of our renewable energy portfolio.

We also continue to increase the amount of renewable energy in our regulated portfolio through power purchase agreements. In recent years, we have entered into contracts to buy more than 170 MW of renewable energy, including wind, solar, hydroelectric and landfill gas.

Commercial renewables business

Our commercial renewables business has initially been focused on land-based wind energy, currently the most economical renewable power source. By the end of 2010, we expect to have nearly 1,000 MW of commercial wind power in operation. We have been very successful in bringing new wind projects on line ahead of schedule and under budget. These projects are backed by long-term contracts with creditworthy partners — a low-risk approach that we are also applying to solar, biomass and new transmission projects.

In January 2010, we announced our first commercial photovoltaic solar venture, the Blue Wing Solar Project in San Antonio, Texas. This 14-MW, 139-acre solar photovoltaic farm includes a 30-year power purchase agreement with San Antonio-based CPS Energy, one of the largest municipal utilities in the United States. Our solar strategy also involves joint development of commercial projects in the United States with China-based ENN Group.

Last year, the U.S. Department of Energy awarded us a matching grant worth $22 million to design, build and install one of the nation's first demonstrations of energy storage at our 153-MW Notrees wind farm in Texas. If it proves to be cost-effective, we could adopt similar storage solutions at some of our other power plants.

Also in 2009, ADAGE, the biopower company we own with AREVA, began the permitting process to build two 55-MW carbon-neutral biomass plants in Florida that will generate electricity by burning wood waste. In early 2010, ADAGE and John Deere announced an alliance for collecting, bundling and transporting wood debris from regional logging operations in western Washington to fuel a proposed 55-MW biomass power plant in that region.

Finally, we became the lead investor in GreenTrees, a program that aims to offset carbon emissions through the reforestation of 1 million acres in the southeastern United States. Our initial investment funded the planting of more than 1 million trees on approximately 1,700 acres in Arkansas.

WHAT IF WE'RE WRONG ABOUT CLIMATE CHANGE?

I have described our strategy for providing our customers with affordable, reliable and cleaner energy.

But what if we're wrong about the imperative to reduce CO_2 and other greenhouse gas emissions? That is the subject of a high-profile debate, as the integrity of scientific research supporting the threat of climate change continues to be scrutinized.

I have thought about this long and hard. What if we are dead wrong? Would the course we've charted for our company and our customers be misguided? Would we change our plans if it were unlikely that Congress or the EPA would ever regulate carbon emissions?

My answer is "no."

STRATEGIC FOCUS FINANCIAL STRENGTH

Q: How will Duke Energy maintain its financial strength?

A: Our financial objectives include growing our earnings and dividends, allocating capital efficiently and earning competitive returns, while maintaining the strength of our balance sheet. Our financial strategy supports our historical focus of providing affordable, reliable and increasingly clean energy to our customers, while earning good returns for our investors.

Q: How do you balance short-term economic pressures with the long-term investments needed to meet the needs of your customers, and achieve business growth?

A: We achieve that balance by maintaining flexibility in our allocation and spending of capital. In 2010, about $3 billion is committed to building our two cleaner-coal plants and two gas plants in our regulated operations, and renewable wind and solar projects being built under long-term contracts in our commercial businesses. About $2 billion is allocated for customer additions and maintenance costs. In the short term, we have some flexibility on the timing of this spend.

We have the greatest flexibility in allocating our discretionary capital. Our 2010 plan includes $200 million of growth capital that has not yet been designated to specific projects. Additionally, we have broad ranges for discretionary spending in 2011 and 2012, the years in which we will be deploying more capital to complete the fleet and grid modernization projects in our regulated operations. As we demonstrated in 2009, we have the flexibility to increase or decrease this discretionary spending as the environment dictates.

Even without carbon regulation, we would still need to complete our Cliffside and Edwardsport advanced coal projects and our two natural gas-fired plants in North Carolina, and pursue the nuclear option. Why? Because we will have to replace nearly every power plant we operate today by 2050, due to normal aging and technological obsolescence.

Why now? Because we must meet our clean energy aspirations and build a flexible generation portfolio that includes all fuel sources. Modernizing our fleet now gives us and our customers the flexibility to respond to unpredictable and ever-changing fuel prices.

We simply cannot rely on renewable energy for most of our power. Wind and solar power are intermittent. As such, they are not as reliable and affordable as baseload plants. Advances in electricity storage technology will continue to make renewables more reliable. Meanwhile, coal-fired plants, nuclear plants and even hydroelectric plants can provide power 24/7, as long as fuel is available.

Furthermore, renewables can lead to energy sprawl, impacting natural habitats and the wildlife that depend on them. Baseload plants have a much smaller footprint, given their land used per unit of energy generated. These are some of the trade-offs we must consider as we continue to work to reduce our carbon footprint.

If we're not wrong about carbon and the scientific consensus continues to be that climate change is a very real risk, then our investments will have positioned our company to be a world leader in cleaner energy.

Repowering our states and creating jobs

Our strategy is also to bolster our local economies and build a solid economic base for future business. Between our Cliffside and Edwardsport projects, two of the largest capital projects under way in their states, approximately 4,000 construction workers are employed. The two North Carolina gas plants represent about another 1,000 construction jobs. The proposed nuclear power plants in South Carolina and Ohio would create an estimated 7,000 peak construction jobs combined — not to mention the hundreds of high-paying permanent jobs and the ongoing contributions to the local communities' tax base once these facilities are operating.

Shedding a Light

To stay informed or to join the conversation on these and other key energy issues, I invite you to visit our new issues-oriented Web site, www.sheddingalight.org. At Shedding a Light, you will find information and a variety of different viewpoints on topics important to our company and our industry.

DELIVERING ON OUR MISSION

I want to thank all of our employees for maintaining our operational excellence and for delivering superior results for our customers, investors and the communities we serve during an especially challenging year. And I want to thank you, our investors, for your support and loyalty. We remain committed to earning good returns for you on your investments.

On behalf of all of our stakeholders, I also thank our board of directors, who provided important insight and counsel during this period of unprecedented uncertainty. I especially want to thank Dudley Taft, president and CEO of Taft Broadcasting Co., who is retiring from our board in 2010. Dudley has been a director of Duke Energy and its predecessor companies since 1985. In his 25 years of dedicated service on our board, he has been a significant contributor to our continued growth and success. We will miss his business acumen, and his direct and practical approach to finding workable solutions. We wish him well in his retirement.

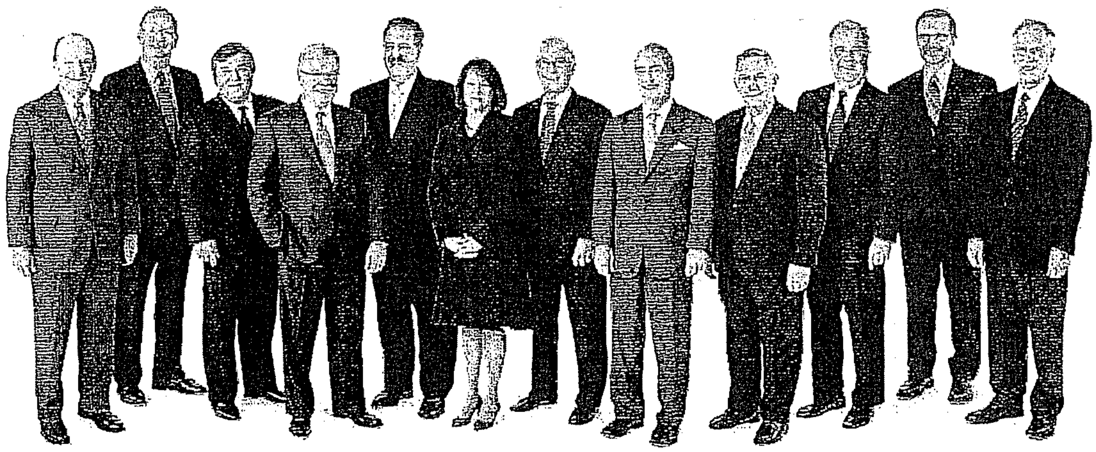
Last year, we welcomed John Forsgren and Jim Reinsch to our board. John is the retired vice chairman, executive vice president and chief financial officer of Northeast Utilities. He has 35 years of corporate finance experience. Jim is the retired senior vice president and partner of Bechtel Group, and past president of Bechtel Nuclear. He has more than 37 years of nuclear experience. John and Jim bring a wealth of knowledge and experience to an already strong board.

Although there is nothing simple about delivering affordable, reliable and clean energy, we are committed to continue delivering on that mission and balancing the needs of all of our stakeholders. We never know what the future will be, but we can anticipate it by looking around the corner and over the horizon. That focus gives us great clarity about what we must do to honor our commitments — today and tomorrow.

James E. Rogers
Chairman, President and Chief Executive Officer

March 15, 2010

BOARD OF DIRECTORS



From left to right: Dudley Taft, Jim Hance Jr., Michael Browning, John Forsgren, Dan DiMicco, Ann Maynard Gray, Jim Reinsch, Jim Rogers, Bill Barnet III, Jim Rhodes, Phil Sharp and Alex Bernhardt Sr.

William (Bill) Barnet III
Chairman, President and
Chief Executive Officer
The Barnet Company Inc. and
Barnet Development Corp.

Chair, Finance and Risk Management Committee

Member, Nuclear Oversight Committee

Director of Duke Energy or its predecessor companies since 2005

G. Alex Bernhardt Sr.
Chairman and
Chief Executive Officer
Bernhardt Furniture Company

Member, Audit Committee, Nuclear Oversight Committee

Director of Duke Energy or its predecessor companies since 1991

Michael G. Browning
President and
Chairman of the Board
Browning Investments Inc.

Chair, Audit Committee

Member, Corporate Governance Committee, Finance and Risk Management Committee

Director of Duke Energy or its predecessor companies since 1990

Daniel R. (Dan) DiMicco
Chairman, President and
Chief Executive Officer
Nucor Corporation

Member, Compensation Committee, Corporate Governance Committee

Director of Duke Energy or its predecessor companies since 2007

John H. Forsgren
Retired Vice Chairman,
Executive Vice President and
Chief Financial Officer
Northeast Utilities

Member, Audit Committee, Compensation Committee

Director of Duke Energy or its predecessor companies since 2009

Ann Maynard Gray
Former President, Diversified
Publishing Group of ABC Inc.

Lead Director

Chair, Corporate Governance Committee

Member, Compensation Committee, Finance and Risk Management Committee

Director of Duke Energy or its predecessor companies since 1994

James H. (Jim) Hance Jr.
Retired Vice Chairman and
Chief Financial Officer
Bank of America Corp.

Chair, Compensation Committee

Member, Finance and Risk Management Committee

Director of Duke Energy or its predecessor companies since 2005

E. James (Jim) Reinsch
Retired Senior Vice President
and Partner
Bechtel Group

Member, Finance and Risk Management Committee, Nuclear Oversight Committee

Director of Duke Energy or its predecessor companies since 2009

James T. (Jim) Rhodes
Retired Chairman, President
and Chief Executive Officer
Institute of Nuclear Power
Operations

Chair, Nuclear Oversight Committee

Member, Audit Committee

Director of Duke Energy or its predecessor companies since 2001

James E. (Jim) Rogers
Chairman, President and
Chief Executive Officer
Duke Energy Corporation

Director of Duke Energy or its predecessor companies since 1988

Philip R. (Phil) Sharp
President
Resources for the Future

Member, Audit Committee, Nuclear Oversight Committee

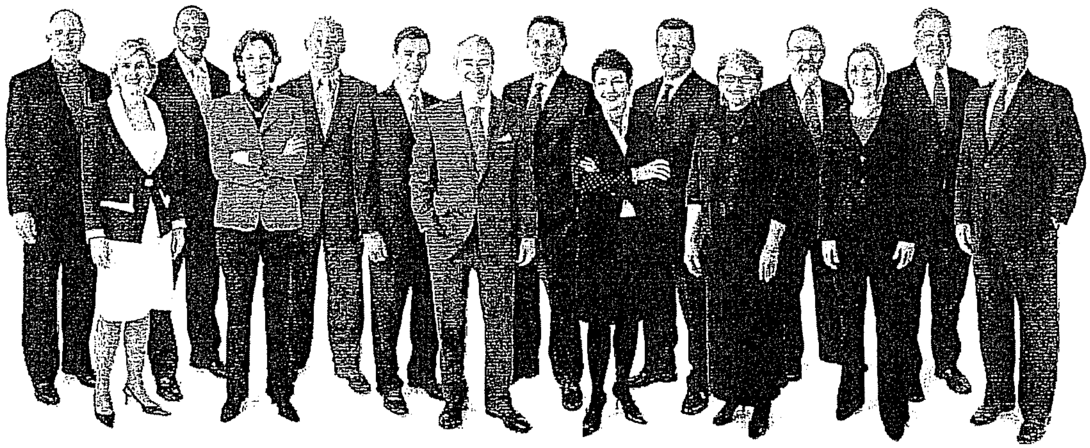
Director of Duke Energy since 2007 and its predecessor companies from 1995-2006

Dudley S. Taft
President and
Chief Executive Officer
Taft Broadcasting Co.

Member, Compensation Committee, Finance and Risk Management Committee

Director of Duke Energy or its predecessor companies since 1985

EXECUTIVE MANAGEMENT



From left to right: Rick Haviland, Jennifer Weber, Brett Carter, Roberta Bowman, Marc Manly, Jim Turner, Jim Rogers, Keith Trent, Lynn Good, Dhiaa Jamil, Ellen Ruff, David Mohler, Julie Janson, Bill Tyndall and Jim Stanley

James E. (Jim) Rogers
Chairman, President and
Chief Executive Officer

Roberta B. Bowman
Senior Vice President and
Chief Sustainability Officer

Brett C. Carter
President – Duke Energy
Carolinas

Lynn J. Good
Group Executive and
Chief Financial Officer

Richard W. (Rick) Haviland
Senior Vice President,
Construction and Major Projects

Dhiaa M. Jamil
Group Executive,
Chief Generation Officer and
Chief Nuclear Officer

Julie S. Janson
President – Duke Energy Ohio
and Duke Energy Kentucky

Marc E. Manly
Group Executive,
Chief Legal Officer and
Corporate Secretary

David W. Mohler
Senior Vice President and
Chief Technology Officer

Ellen T. Ruff
President – Office of Nuclear
Development

Jim L. Stanley
President – Duke Energy Indiana

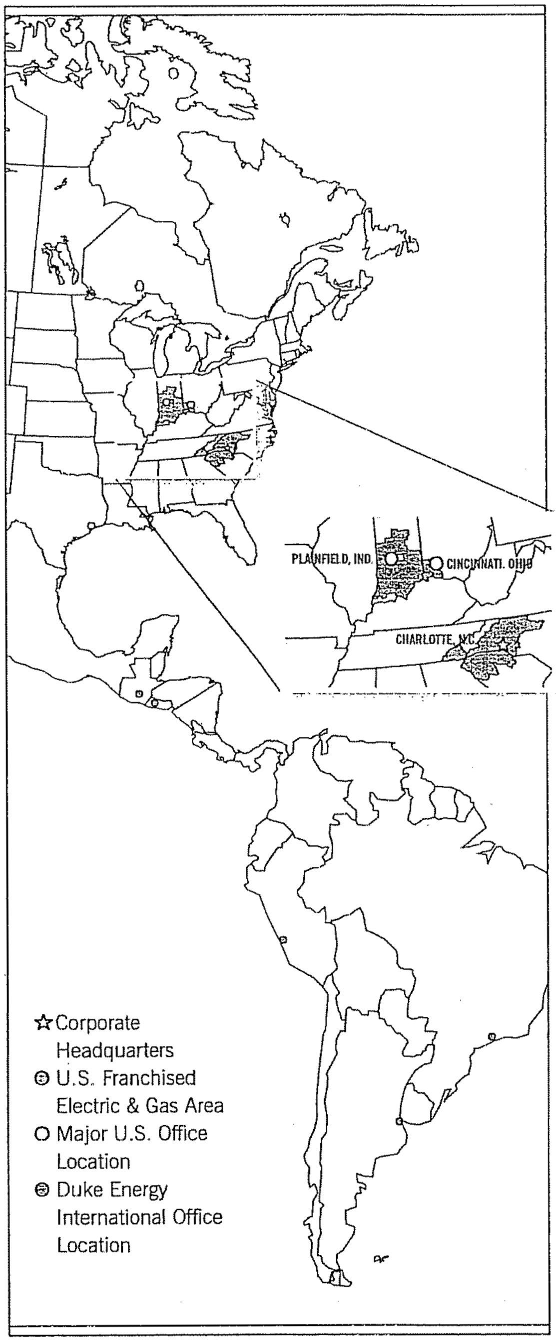
B. Keith Trent
Group Executive and President –
Commercial Businesses

James L. (Jim) Turner
Group Executive; President and
Chief Operating Officer – U.S.
Franchised Electric and Gas

William F. (Bill) Tyndall
Senior Vice President,
Federal Government and
Regulatory Affairs

Jennifer L. Weber
Senior Vice President and
Chief Human Resources Officer

DUKE ENERGY AT A GLANCE



U.S. Franchised Electric and Gas

U.S. Franchised Electric and Gas (USFE&G) consists of Duke Energy's regulated generation, electric and gas transmission and distribution systems. USFE&G's generation portfolio is a balanced mix of energy resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost.

Electric Operations

- Owns approximately 27,000 megawatts (MW) of generating capacity
- Service area covers about 50,000 square miles with an estimated population of 11 million
- Service to approximately 4 million residential, commercial and industrial customers
- Over 151,600 miles of distribution lines and a 20,900-mile transmission system

Gas Operations

- Regulated natural gas transmission and distribution services to approximately 500,000 customers in southwestern Ohio and northern Kentucky

Commercial Power

Commercial Power owns, operates and manages power plants, primarily located in the Midwest. Commercial Power's subsidiary, Duke Energy Retail Sales, serves retail electric customers in Ohio with generation and other energy services at competitive rates. Commercial Power also includes Duke Energy Generation Services (DEGS), an on-site energy solutions and utility services provider.

- Owns and operates a balanced generation portfolio of approximately 7,550 net MW of power generation (excluding wind assets)
- DEGS currently has approximately 735 MW of wind energy in operation and over 5,000 MW of wind energy projects in development

Duke Energy International

Duke Energy International (DEI) operates and manages power generation facilities and engages in sales and marketing of electric power and natural gas outside the U.S. DEI's activities target power generation in Latin America. DEI also has an equity investment in National Methanol Co. in Saudi Arabia, a regional producer of MTBE, a gasoline additive.

- Owns, operates or has substantial interests in approximately 4,000 net MW of generation facilities
- About 75 percent of DEI's generating capacity is hydroelectric

NON-GAAP FINANCIAL MEASURES

Adjusted Diluted Earnings per Share ("EPS")

Duke Energy's 2009 Annual Report references 2009 adjusted diluted EPS of $1 22 and states that adjusted diluted EPS has been essentially flat from 2007 through 2009. Adjusted diluted EPS is a non-GAAP (generally accepted accounting principles) financial measure as it represents diluted EPS from continuing operations attributable to Duke Energy Corporation common shareholders, adjusted for the per share impact of special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. Special items represent certain charges and credits, which management believes will not be recurring on a regular basis, although it is reasonably possible such charges and credits could recur. Mark-to-market adjustments reflect the mark-to-market impact of derivative contracts, which is recognized in GAAP earnings immediately as such derivative contracts do not qualify for hedge accounting or regulatory accounting, used in Duke Energy's hedging of a portion of the economic value of certain of its generation assets in the Commercial Power segment. The economic value of the generation assets is subject to fluctuations in fair value due to market price volatility of the input and output commodities (e.g., coal, power) and, as such, the economic hedging involves both purchases and sales of those input and output commodities related to the generation assets. Because the operations of the generation assets are accounted for under the accrual method, management believes that excluding the impact of mark-to-market changes of the economic hedge contracts from adjusted earnings until settlement better matches the financial impacts of the hedge contract with the portion of the economic value of the underlying hedged asset. Management believes that the presentation of adjusted diluted EPS provides useful information to investors, as it provides them an additional relevant comparison of the company's performance across periods. Adjusted diluted EPS is also used as a basis for employee incentive bonuses.

The most directly comparable GAAP measure for adjusted diluted EPS is reported diluted EPS from continuing operations attributable to Duke Energy Corporation common shareholders, which includes the impact of special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. The following is a reconciliation of reported diluted EPS from continuing operations to adjusted diluted EPS for 2009, 2008, and 2007:

	2009	2008	2007
Diluted EPS from continuing operations, as reported	$ 0.82	$ 1 01	$ 1 20
Diluted EPS from discontinued operations, as reported	0.01	0 01	(0 02)
Diluted EPS from extraordinary items, as reported	—	0.05	—
Diluted EPS, as reported	$ 0.83	$ 1 07	$ 1 18
Adjustments to reported EPS:			
Diluted EPS from discontinued operations	(0.01)	(0 01)	0 02
Diluted EPS from extraordinary items	—	(0 05)	—
Diluted EPS impact of special items and mark-to-market in Commercial Power (see below)	0.40	0.20	0.03
Diluted EPS, adjusted	$ 1.22	$ 1 21	$ 1 23

The following is the detail of the $(0.40) per share in special items and mark-to-market in Commercial Power impacting adjusted diluted EPS for 2009:

(In millions, except per-share amounts)	Pre-Tax Amount	Tax Effect	2009 Diluted EPS Impact
Costs to achieve the Cinergy merger	$ (25)	$10	$(0.01)
Crescent related guarantees and tax adjustments	(26)	(3)	(0.02)
International transmission adjustment	(32)	10	(0.02)
Goodwill and other impairments	(431)	21	(0.32)
Mark-to-market impact of economic hedges	(60)	22	(0.03)
Total Adjusted EPS impact			$(0.40)

The following is the detail of the $(0.20) per share in special items and mark-to-market in Commercial Power impacting adjusted diluted EPS for 2008:

(In millions, except per-share amounts)	Pre-Tax Amount	Tax Effect	2008 Diluted EPS Impact
Costs to achieve the Cinergy merger	$ (44)	$17	$(0.02)
Crescent project impairments	(214)	83	(0 10)
Emission Allowances impairment	(82)	30	(0.04)
Mark-to-market impact of economic hedges	(75)	27	(0.04)
Total Adjusted EPS impact			$(0.20)

The following is the detail of the $(0.03) per share in special items and mark-to-market in Commercial Power impacting adjusted diluted EPS for 2007:

(In millions, except per-share amounts)	Pre-Tax Amount	Tax Effect	2007 Diluted EPS Impact
Costs to achieve the Cinergy merger	$(54)	$19	$(0.03)
Convertible debt costs associated with the spinoff of Spectra Energy	(21)	—	(0.02)
IT severance costs	(12)	4	—
Settlement reserves and adjustments	24	(9)	0.01
Mark-to-market impact of economic hedges	13	(5)	0.01
Total Adjusted EPS impact			$(0.03)

2010 Adjusted Diluted EPS Outlook

Duke Energy's 2009 Annual Report references Duke Energy's forecasted 2010 adjusted diluted EPS outlook range of $1.25-$1.30 per share and the 2009 EPS incentive target of $1.20 per share. The EPS measure used for employee incentive bonuses is primarily based on adjusted diluted EPS. Additionally, reference is made to the forecasted range of growth of 4%-6% in adjusted diluted EPS (on a compound annual growth rate ("CAGR") basis) from a base of adjusted diluted EPS for 2009 of $1.22. Adjusted diluted EPS is a non-GAAP financial measure as it represents diluted EPS from continuing operations attributable to Duke Energy Corporation shareholders, adjusted for the per-share impact of special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. Special items represent certain charges and credits, which management believes will not be recurring on a regular basis, although it is reasonably possible such charges and credits could recur. Mark-to-market adjustments reflect the mark-to-market impact of derivative contracts, which is recognized in GAAP earnings immediately as such derivative contracts do not qualify for hedge accounting or regulatory accounting treatment, used in Duke Energy's hedging of a portion of the economic value of its generation assets in the Commercial Power segment (as discussed separately under "Adjusted Diluted Earnings per Share ('EPS')"). The most directly comparable GAAP measure for adjusted diluted EPS is reported diluted EPS from continuing operations attributable to Duke Energy Corporation common shareholders, which includes the impact of special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project special items or mark-to-market adjustments for future periods.

Forecasted Adjusted Segment EBIT and Other Net Expenses for 2010

Duke Energy's 2009 Annual Report includes a discussion of forecasted 2010 adjusted EBIT for each of Duke Energy's reportable segments as a percentage of forecasted 2010 adjusted total segment EBIT. The primary performance measure used by management to evaluate segment performance is segment EBIT from continuing operations, which at the segment level, represents all profits from continuing operations (both operating and non-operating), including any equity in earnings of unconsolidated affiliates, before deducting interest and taxes, and is net of the income attributable to non-controlling interests. Management believes segment EBIT from continuing operations, which is the GAAP measure used to report segment results, is a good indicator of each segment's operating performance as it represents the results of Duke Energy's ownership interests in continuing operations without regard to financing methods or capital structures. Duke Energy also uses adjusted segment EBIT and adjusted Other net expenses (including adjusted equity earnings for Crescent Resources) as a measure of historical and anticipated future segment and Other performance. When used for future periods, adjusted segment EBIT and adjusted Other net expenses may also include any amounts that may be reported as discontinued operations or extraordinary items.

Adjusted segment EBIT and Other net expenses are non-GAAP financial measures as they represent reported segment EBIT and Other net expenses adjusted for the impact of special items and the mark-to market impacts of economic hedges in the Commercial Power segment. Special items represent certain charges and credits, which management believes will not be recurring on a regular basis, although it is reasonably possible such charges and credits could recur. Mark-to-market adjustments reflect the mark-to-market impact of derivative contracts, which is recognized in GAAP earnings immediately as such derivative contracts do not qualify for hedge accounting or regulatory accounting, used in Duke Energy's hedging of a portion of the economic value of certain of its generation assets in the Commercial Power segment (as discussed above under "Adjusted Diluted Earnings per Share ('EPS')"). Management believes that the presentation of adjusted segment EBIT and adjusted Other net expenses provides useful information to investors, as it provides them an additional relevant comparison of a segment's or Other's performance across periods. The most directly comparable GAAP measures for adjusted segment EBIT and Other net expenses are reported segment EBIT and Other net expenses, which represent segment and Other results from continuing operations, including any special items and the mark-to-market impacts of economic hedges in the Commercial Power segment. Due to the forward-looking nature of this non-GAAP financial measure for 2010, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project special items or mark-to-market adjustments for future periods.

DUKE ENERGY CORPORATION

2009 FORM 10-K

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

FORM 10-K

FOR ANNUAL AND TRANSITION REPORTS
PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2009 or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from __________ to __________

Commission file number **1-32853**

DUKE ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**20-2777218**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
526 South Church Street, Charlotte, North Carolina	**28202-1803**
(Address of principal executive offices)	*(Zip Code)*

704-594-6200
(Registrant's telephone number, including area code)

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

Title of each class	*Name of each exchange on which registered*
Common Stock, $0.001 par value	**New York Stock Exchange, Inc.**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

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

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).
Yes ☐ No ☒

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant at June 30, 2009	$18,836,000,000
Number of shares of Common Stock, $0.001 par value, outstanding at February 22, 2010	1,309,314,484

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DUKE ENERGY CORPORATION
FORM 10-K FOR THE YEAR ENDED
DECEMBER 31, 2009

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- State, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements, as well as rulings that affect cost and investment recovery or have an impact on rate structures;
- Costs and effects of legal and administrative proceedings, settlements, investigations and claims;
- Industrial, commercial and residential growth or decline in Duke Energy Corporation's (Duke Energy) service territories, customer base or customer usage patterns;
- Additional competition in electric markets and continued industry consolidation;
- Political and regulatory uncertainty in other countries in which Duke Energy conducts business;
- The influence of weather and other natural phenomena on Duke Energy's operations, including the economic, operational and other effects of storms, hurricanes, droughts and tornados;
- The timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates;
- Unscheduled generation outages, unusual maintenance or repairs and electric transmission system constraints;
- The performance of electric generation and of projects undertaken by Duke Energy's non-regulated businesses;
- The results of financing efforts, including Duke Energy's ability to obtain financing on favorable terms, which can be affected by various factors, including Duke Energy's credit ratings and general economic conditions;
- Declines in the market prices of equity securities and resultant cash funding requirements for Duke Energy's defined benefit pension plans;
- The level of credit worthiness of counterparties to Duke Energy's transactions;
- Employee workforce factors, including the potential inability to attract and retain key personnel;
- Growth in opportunities for Duke Energy's business units, including the timing and success of efforts to develop domestic and international power and other projects;
- Construction and development risks associated with the completion of Duke Energy's capital investment projects in existing and new generation facilities, including risks related to financing, obtaining and complying with terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards, as well as the ability to recover costs from customers in a timely manner or at all;
- The effect of accounting pronouncements issued periodically by accounting standard-setting bodies; and
- The ability to successfully complete merger, acquisition or divestiture plans.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Duke Energy has described. Duke Energy undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

ITEM 1. BUSINESS.

GENERAL

Overview.

Duke Energy Corporation (collectively with its subsidiaries, Duke Energy) is an energy company located primarily in the Americas that provides its services through the business segments described below.

Duke Energy Holding Corp. (Duke Energy HC) was incorporated in Delaware on May 3, 2005 as Deer Holding Corp., a wholly-owned subsidiary of Duke Energy Corporation (Old Duke Energy, for purposes of this discussion regarding the merger). In the second quarter of 2006, Duke Energy and Cinergy Corp. (Cinergy) consummated a merger which combined the Duke Energy and Cinergy regulated franchises, as well as deregulated generation in the Midwestern United States. On April 3, 2006, in accordance with the merger agreement, Old Duke Energy and Cinergy merged into wholly-owned subsidiaries of Duke Energy HC, resulting in Duke Energy HC becoming the parent entity. In connection with the closing of the merger transactions, Duke Energy HC changed its name to Duke Energy Corporation (New Duke Energy or Duke Energy) and Old Duke Energy converted into a limited liability company named Duke Power Company LLC (subsequently renamed Duke Energy Carolinas, LLC (Duke Energy Carolinas) effective October 1, 2006). As a result of the merger transaction, each outstanding share of Cinergy common stock was converted into 1.56 shares of common stock of Duke Energy, which resulted in the issuance of approximately 313 million shares of Duke Energy common stock. Additionally, each share of common stock of Old Duke Energy was converted into one share of Duke Energy common stock. Old Duke Energy is the predecessor of Duke Energy for purposes of U.S. securities regulations governing financial statement filing.

On January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses, named Spectra Energy Corp. (Spectra Energy), including its wholly-owned subsidiary Spectra Energy Capital, LLC (Spectra Energy Capital, formerly Duke Capital LLC). The natural gas businesses spun off primarily consisted of Duke Energy's Natural Gas Transmission business segment and Duke Energy's 50% ownership interest in DCP Midstream, LLC (DCP Midstream, formerly Duke Energy Field Services, LLC), which was part of the Field Services business segment.

During the third quarter of 2005, Duke Energy's Board of Directors authorized and directed management to execute the sale or disposition of substantially all of former Duke Energy North America's (DENA) remaining assets and contracts outside the Midwestern United States and certain contractual positions related to the Midwestern assets. The exit plan was completed in the second quarter of 2006. Certain assets of the former DENA business were transferred to the Commercial Power business segment and certain operations that Duke Energy continues to wind-down are in Other.

Business Segments.

At December 31, 2009, Duke Energy operated the following business segments, all of which are considered reportable segments under the applicable accounting rules: U.S. Franchised Electric and Gas, Commercial Power and International Energy. Duke Energy's chief operating decision maker regularly reviews financial information about each of these business segments in deciding how to allocate resources and evaluate performance. For additional information on each of these business segments, including financial and geographic information about each reportable business segment, see Note 2 to the Consolidated Financial Statements, "Business Segments."

The following is a brief description of the nature of operations of each of Duke Energy's reportable business segments, as well as Other.

U.S. Franchised Electric and Gas.

U.S. Franchised Electric and Gas generates, transmits, distributes and sells electricity in central and western North Carolina, western South Carolina, southwestern Ohio, central, north central and southern Indiana, and northern Kentucky. U.S. Franchised Electric and Gas also transports and sells natural gas in southwestern Ohio and northern Kentucky. It conducts operations primarily through Duke Energy Carolinas, LLC (Duke Energy Carolinas), the regulated transmission and distribution operations of Duke Energy Ohio, Inc. (Duke Energy Ohio), Duke Energy Indiana, Inc. (Duke Energy Indiana) and Duke Energy Kentucky, Inc. (Duke Energy Kentucky). These electric and gas operations are subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (PSCSC), the Public Utilities Commission of Ohio (PUCO), the Indiana Utility Regulatory Commission (IURC) and the Kentucky Public Service Commission (KPSC). The substantial majority of U.S. Franchised Electric and Gas' operations are regulated and, accordingly, these operations qualify for regulatory accounting treatment.

Commercial Power.

Commercial Power owns, operates and manages power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants as well as other contractual positions. Commercial Power's generation operations in the Midwest consist of generation assets located in Ohio, acquired from Cinergy in April 2006, which are dedicated under the Electric Security Plan (ESP), and the five Midwestern gas-fired non-regulated generation assets that were a portion of the former DENA operations, which are dispatched into wholesale markets. Commercial Power's assets, excluding wind energy generation assets, comprise approximately 7,550 net megawatts (MW) of power generation primarily located in the Midwestern U.S. The asset portfolio has a diversified fuel mix with baseload and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units. Effective January 1, 2009, approximately half of Commercial Power's Ohio-based generation assets operate under an ESP, which expires on December 31, 2011. Prior to the ESP, these generation assets had been contracted through the Rate Stabilization Plan (RSP), which expired on December 31, 2008. As a result of the approval of the ESP, certain of Commercial Power's operations qualified for regulatory accounting treatment effective December 17,

2008. For more information on the RSP and ESP, as well as the reapplication of regulatory accounting to certain of its operations, see the "Commercial Power" section below. Commercial Power also has a retail sales subsidiary, Duke Energy Retail Sales (DERS), which is certified by the PUCO as a Competitive Retail Electric Service (CRES) provider in Ohio. DERS serves retail electric customers in Southwest, West Central and Northern Ohio with generation and other energy services at competitive rates. During 2009, due to increased levels of customer switching as a result of the competitive markets in Ohio, DERS has focused on acquiring customers that had previously been served by Duke Energy Ohio under the ESP, as well as those previously served by other Ohio franchised utilities. Through Duke Energy Generation Services, Inc. and its affiliates (DEGS), Commercial Power develops, owns and operates electric generation for large energy consumers, municipalities, utilities and industrial facilities. DEGS currently manages 6,150 MW of power generation at 21 facilities throughout the U.S. In addition, DEGS engages in the development, construction and operation of wind energy projects. Currently, DEGS has over 5,000 MW of wind energy projects in the development pipeline with approximately 735 net MW of wind generating capacity in operation as of December 31, 2009. DEGS is also developing transmission, solar and biomass projects.

International Energy.

International Energy principally owns, operates and manages power generation facilities, and engages in sales and marketing of electric power and natural gas outside the U.S. It conducts operations primarily through Duke Energy International, LLC (DEI) and its affiliates and its activities target power generation in Latin America. Through its wholly-owned subsidiary Aguaytia Energy del Perú S.R.L. Ltda. (Aguaytia) and its equity method investment in National Methanol Company (NMC), which is located in Saudi Arabia, International Energy also engages in the production of natural liquid gas and methanol and methyl tertiary butyl ether (MTBE). Additionally, International Energy had an equity method investment in Attiki Gas Supply S.A. (Attiki), a natural gas distributor in Greece, which it decided to abandon, along with the related non-recourse debt, in December 2009.

Other.

The remainder of Duke Energy's operations is presented as Other. While it is not considered a business segment, Other primarily includes certain unallocated corporate costs, Bison Insurance Company Limited (Bison), Duke Energy's wholly-owned captive insurance subsidiary, Duke Energy's effective 50% interest in the Crescent JV (Crescent) and DukeNet Communications, LLC (DukeNet) and related telecom businesses. Additionally, Other includes the remaining portion of Duke Energy's business formerly known as DENA that was not exited or transferred to Commercial Power, primarily Duke Energy Trading and Marketing, LLC (DETM), which is 60% owned by Duke Energy and 40% owned by Exxon Mobil Corporation and management is currently in the process of winding down.

Unallocated corporate costs include certain costs not allocable to Duke Energy's reportable business segments, primarily governance costs, costs to achieve mergers and divestitures (such as the Cinergy merger and spin-off of Spectra Energy) and costs associated with certain corporate severance programs. Bison's principal activities as a captive insurance entity include the insurance and reinsurance of various business risks and losses, such as property, business interruption and general liability of subsidiaries and affiliates of Duke Energy. Crescent, which develops and manages high-quality commercial, residential and multi-family real estate projects primarily in the Southeastern and Southwestern U.S, filed Chapter 11 petitions in a U.S. Bankruptcy Court in June 2009. As a result of recording its proportionate share of impairment charges recorded by Crescent during 2008, the carrying value of Duke Energy's investment balance in Crescent is zero and Duke Energy discontinued applying the equity method of accounting to its investment in Crescent in the third quarter of 2008 and has not recorded its proportionate share of any Crescent earnings or losses since the third quarter of 2008. DukeNet develops, owns and operates a fiber optic communications network, primarily in the Southeast U.S., serving wireless, local and long-distance communications companies, internet service providers and other businesses and organizations.

General.

Duke Energy is a Delaware corporation. Its principal executive offices are located at 526 South Church Street, Charlotte, North Carolina 28202-1803. The telephone number is 704-594-6200. Duke Energy electronically files reports with the Securities and Exchange Commission (SEC), including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxies and amendments to such reports. The public may read and copy any materials that Duke Energy files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at *http://www.sec.gov*. Additionally, information about Duke Energy, including its reports filed with the SEC, is available through Duke Energy's Web site at *http://www.duke-energy.com*. Such reports are accessible at no charge through Duke Energy's Web site and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC.

Glossary of Terms

The following terms or acronyms used in this Form 10-K are defined below:

Term or Acronym	Definition
AAC	Annually Adjusted Component
ADEA	Age Discrimination in Employment
AEP	American Electric Power Company, Inc.
AFUDC	Allowance for Funds Used During Construction
Aguaytia	Aguaytia Energy del Perú S.R.L. Ltda.
ANEEL	Brazilian Electricity Regulatory Agency
AOCI	Accumulated Other Comprehensive Income
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Attiki	Attiki Gas Supply S.A.
Bison	Bison Insurance Company Limited
BPM	Bulk Power Marketing
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
Catamount	Catamount Energy Corporation
CC	Combined Cycle
Cinergy Receivables	Cinergy Receivables Company, LLC
CMP	Central Maine Power Company
CT	Combustion Turbine
Cinergy	Cinergy Corp.
CO_2	Carbon Dioxide
COL	Combined Construction and Operating License
CPCN	Certificate of Public Convenience and Necessity
Crescent	Crescent JV
CWIP	Construction Work-in-Progress
DAQ	Division of Air Quality
DB	Defined Benefit Pension Plan
DCP Midstream	DCP Midstream, LLC (formerly Duke Energy Field Services, LLC)
DECE	Duke Energy Commercial Enterprises, Inc.
DEGS	Duke Energy Generation Services, Inc.
DEI	Duke Energy International, LLC
DEIGP	Duke Energy International Geracao Paranapenema S.A.
DENA	Duke Energy North America
DENR	Department of Environment and Natural Resources
DERF	Duke Energy Receivables Finance Company, LLC
DERS	Duke Energy Retail Sales
DETM	Duke Energy Trading and Marketing, LLC
DOE	Department of Energy
DRIP	Dividend Reinvestment Plan
DSM	Demand Side Management
Duke Energy	Duke Energy Corporation (collectively with its subsidiaries)
Duke Energy Carolinas	Duke Energy Carolinas, LLC
Duke Energy Indiana	Duke Energy Indiana, Inc.
Duke Energy Kentucky	Duke Energy Kentucky, Inc.
Duke Energy Ohio	Duke Energy Ohio, Inc.
EPA	Environmental Protection Agency
EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act
ESP	Electric Security Plan
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FPP	Fuel and Purchased Power
GAAP	Generally Accepted Accounting Principles in the United States
GWh	Gigawatt-hours
HAP	Hazardous Air Pollutant
IGCC	Integrated Gasification Combined Cycle
IMPA	Indiana Municipal Power Agency
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
KPSC	Kentucky Public Service Commission
KV	Kilovolt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
MACT	Maximum achievable control technology
Mcf	Thousand cubic feet
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British Thermal Unit
Moody's	Moody's Investor Services

PART I

Term or Acronym	Definition	Term or Acronym	Definition
MRO	Market Rate Option	REPS	Renewable Energy and Energy Efficiency Portfolio Standard
MTBE	Methyl tertiary butyl ether	RICO	Racketeer Influenced and Corrupt Organizations
MW	Megawatt	RSP	Rate Stabilization Plan
MWh	Megawatt-hour	RTO	Regional Transmission Organization
NCUC	North Carolina Utilities Commission	SB 221	Ohio Senate Bill 221
NDTF	Nuclear Decommissioning Trust Funds	SCEUC	South Carolina Energy Users Committee
NEIL	Nuclear Electric Insurance Limited	sEnergy	sEnergy Insurance Limited
NMC	National Methanol Company	SEC	Securities and Exchange Commission
NO_x	Nitrogen oxide	SHGP	South Houston Green Power, L.P.
NPNS	Normal purchase/normal sale	SO_2	Sulfur dioxide
NRC	Nuclear Regulatory Commission	SPE	Special Purpose Entity
NSR	New Source Review	Spectra Energy	Spectra Energy Corp.
OCC	Office of the Ohio Consumers' Counsel	Spectra Capital	Spectra Energy Capital, LLC (formerly Duke Capital LLC)
ORS	South Carolina Office of Regulatory Staff	S&P	Standard & Poor's
OUCC	Indiana Office of Utility Consumer Counselor	Stimulus Bill	The American Recovery and Reinvestment Act of 2009
Pioneer Transmission	Pioneer Transmission, LLC	Synfuel	Synthetic Fuel
PSCSC	Public Service Commission of South Carolina	VDEQ	Virginia Department of Environmental Quality
PUCO	Public Utilities Commission of Ohio	VIE	Variable Interest Entity
PUHCA	Public Utility Holding Company Act of 1935, as amended	WACC	Weighted Average Cost of Capital
QSPE	Qualifying Special Purpose Entity	WARN	North Carolina Waste Awareness Reduction Network
		WVPA	Wabash Valley Power Association, Inc.

The following sections describe the business and operations of each of Duke Energy's reportable business segments, as well as Other. (For more information on the operating outlook of Duke Energy and its reportable segments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations, Introduction — Executive Overview and Economic Factors for Duke Energy's Business". For financial information on Duke Energy's reportable business segments, see Note 2 to the Consolidated Financial Statements, "Business Segments.")

U.S. FRANCHISED ELECTRIC AND GAS

Service Area and Customers

U.S. Franchised Electric and Gas generates, transmits, distributes and sells electricity and transports and sells natural gas. It conducts operations primarily through Duke Energy Carolinas, the regulated transmission and distribution operations of Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky (Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky collectively referred to as Duke Energy Midwest). Its service area covers about 50,000 square miles with an estimated population of 11 million in central and western North Carolina, western South Carolina, southwestern Ohio, central, north central and southern Indiana, and northern Kentucky. U.S. Franchised Electric and Gas supplies electric service to approximately 4 million residential, commercial and industrial customers over 151,600 miles of distribution lines and a 20,900 mile transmission system. U.S. Franchised Electric and Gas provides domestic regulated transmission and distribution services for natural gas to approximately 500,000 customers in southwestern Ohio and northern Kentucky via approximately 7,200 miles of gas mains (gas distribution lines that serve as a common source of supply for more than one service line) and approximately 6,000 miles of service lines. Electricity is also sold wholesale to incorporated municipalities and to public and private utilities. In addition, municipal and cooperative customers who purchased portions of the power generated by the Catawba Nuclear Station may also buy power from a variety of suppliers, including Duke Energy Carolinas, through contractual agreements. For more information on the Catawba Nuclear Station joint ownership, see Note 5 to the Consolidated Financial Statements, "Joint Ownership of Generating and Transmission Facilities."

Duke Energy Carolinas' service area has a diversified commercial and industrial presence. Manufacturing continues to be one of the largest contributors to the economy in the region. Other sectors such as finance, insurance, real estate services, and local government also constitute key components of the states' gross domestic product. Chemicals, rubber and plastics, textile and motor vehicle manufacturing industries were among the most significant contributors to the Duke Energy Carolinas' industrial sales.

Duke Energy Ohio's and Duke Energy Kentucky's service area both have a diversified commercial and industrial presence. Major components of the economy include manufacturing, real estate and rental leasing, wholesale trade, financial and insurance services, retail trade, education, healthcare and professional/business services.

The primary metals industry, transportation equipment, chemicals, and paper and plastics were the most significant contributors to the area's manufacturing output and Duke Energy Ohio's and Duke Energy Kentucky's industrial sales revenue for 2009. Food and beverage manufacturing, fabricated metals, and electronics also have a strong impact on the area's economic growth and the region's industrial sales.

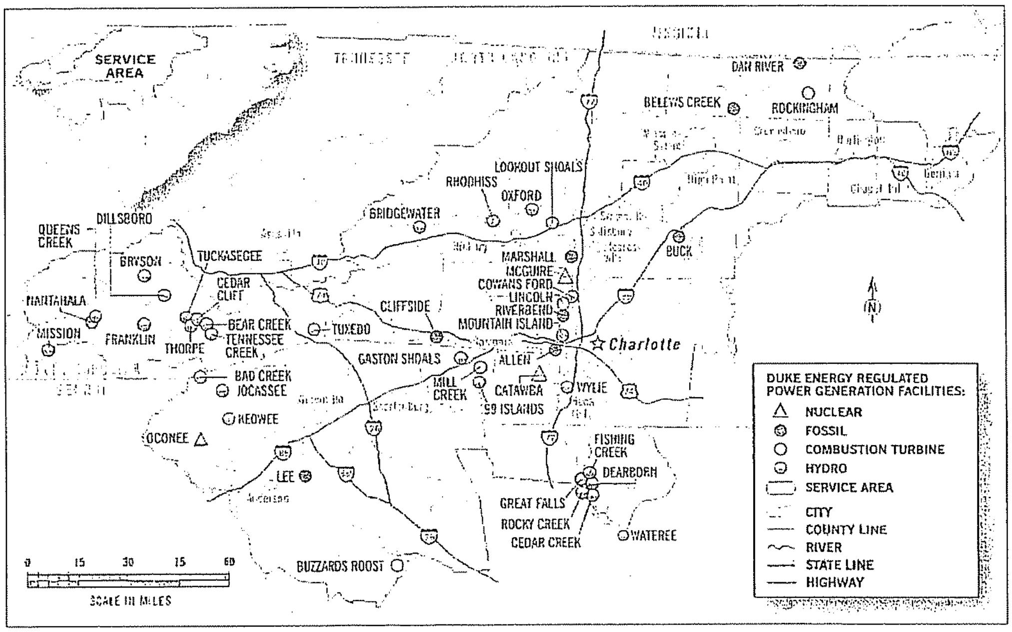
Industries of major economic significance in Duke Energy Indiana's service territory include food products, stone, clay and glass, primary metals, and transportation. Other significant industries operating in the area include chemicals, fabricated metal, and other manufacturing. Key sectors among general service customers include education and retail trade.

The number of residential and general service customers within the U.S. Franchised Electric and Gas' service territory, as well as sales to these customers, is expected to increase over time. However, growth in the near-term is being hampered by the current economic conditions. Industrial sales declined in 2009 when compared to 2008. While the decline in the sales volumes to industrial customers began to stabilize in the second half of 2009, the level of sales to industrial customers is expected to remain a smaller, yet still significant, portion of U.S. Franchised Electric and Gas sales in the foreseeable future.

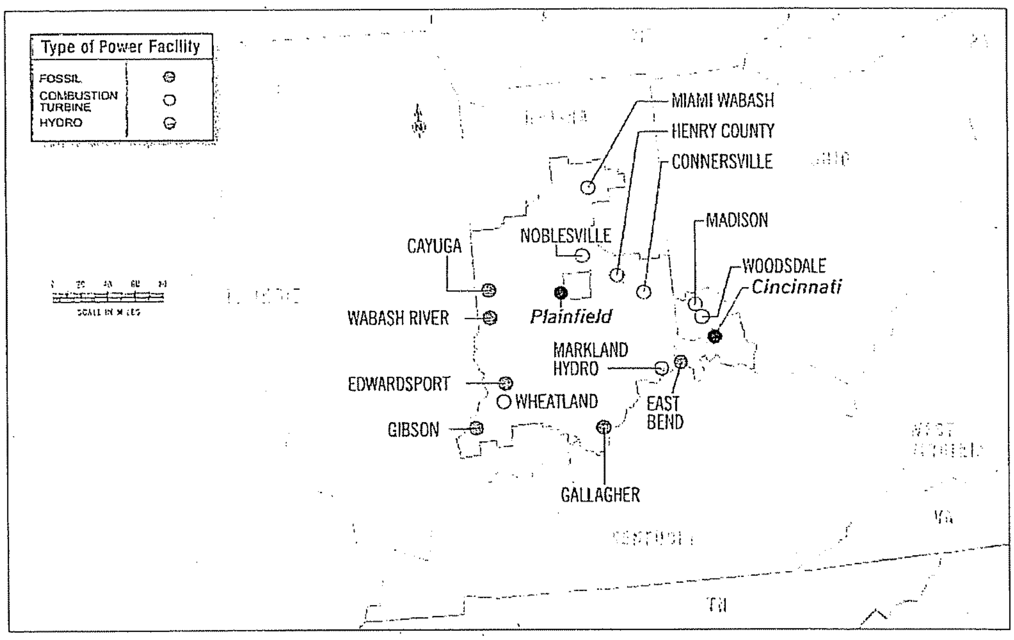
U.S. Franchised Electric and Gas' costs and revenues are influenced by seasonal patterns. Peak sales of electricity occur during the summer and winter months, resulting in higher revenue and cash flows during those periods. By contrast, fewer sales of electricity occur during the spring and fall, allowing for scheduled plant maintenance during those periods. Peak gas sales occur during the winter months.

The following maps show the U.S. Franchised Electric and Gas' service territories and operating facilities.

U.S. Franchised Electric and Gas Carolinas Power General Facilities



U.S. Franchised Electric and Gas Midwest Power Generation Regulated Facilities



Energy Capacity and Resources

Electric energy for U.S. Franchised Electric and Gas' customers is generated by three nuclear generating stations with a combined owned capacity of 5,173 MW (including Duke Energy's approximate 19% ownership in the Catawba Nuclear Station), fifteen coal-fired stations with an overall combined owned capacity of 13,189 MW (including Duke Energy's 69% ownership in the East Bend Steam Station and 50.05% ownership in Unit 5 of the Gibson Steam Station), thirty-one hydroelectric stations (including two pumped-storage facilities) with a combined owned capacity of 3,263 MW, fifteen combustion turbine (CT) stations burning natural gas, oil or other fuels with an overall combined owned capacity of 5,047 MW and one combined cycle (CC) station burning natural gas with an owned capacity of 285 MW. Energy and capacity are also supplied through contracts with other generators and purchased on the open market. Factors that could cause U.S. Franchised Electric and Gas to purchase power for its customers include generating plant outages, extreme weather conditions, generation reliability during the summer, growth, and price. U.S. Franchised Electric and Gas has interconnections and arrangements with its neighboring utilities to facilitate planning, emergency assistance, sale and purchase of capacity and energy, and reliability of power supply.

U.S. Franchised Electric and Gas' generation portfolio is a balanced mix of energy resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet its obligation to serve native-load customers. All options, including owned generation resources and purchased power opportunities, are continually evaluated on a real-time basis to select and dispatch the lowest-cost resources available to meet system load requirements. The vast majority of customer energy needs are met by large, low-energy-production-cost nuclear and coal-fired generating units that operate almost continuously (or at baseload levels). In 2009, approximately 98.1% of the total generated energy came from U.S. Franchised Electric and Gas' low-cost, efficient nuclear and coal units (59.6% coal and 38.5% nuclear). The remaining energy needs were supplied by hydroelectric, CT and CC generation or economic purchases from the wholesale market.

Hydroelectric (both conventional and pumped storage) in the Carolinas and gas/oil CT and CC stations in both the Carolinas and Midwest operate primarily during the peak-hour load periods (at peaking levels) when customer loads are rapidly changing. CT's and CC's produce energy at higher production costs than either nuclear or coal, but are less expensive to build and maintain, and can be rapidly started or stopped as needed to meet changing customer loads. Hydroelectric units produce low-cost energy, but their operations are limited by the availability of water flow.

U.S. Franchised Electric and Gas' major pumped-storage hydroelectric facilities offer the added flexibility of using low-cost off-peak energy to pump water that will be stored for later generation use during times of higher-cost on-peak generation periods. These facilities allow U.S. Franchised Electric and Gas to maximize the value spreads between different high- and low-cost generation periods.

U.S. Franchised Electric and Gas is engaged in planning efforts to meet projected load growth in its service territories. Long-term projections indicate a need for capacity additions, which may include new nuclear, integrated gasification combined cycle (IGCC), coal facilities or gas-fired generation units. Because of the long lead times required to develop such assets, U.S. Franchised Electric and Gas is taking steps now to ensure those options are available. Significant current or potential future capital projects are discussed below.

South Carolina passed new energy legislation South Carolina Senate Bill 431 (S 431) which became effective May 3, 2007. This legislation includes provisions to provide assurance of cost recovery related to a utility's incurrence of project development costs associated with nuclear baseload generation, cost recovery assurance for construction costs associated with nuclear or coal baseload generation, and the ability to recover financing costs for new nuclear baseload generation in rates during construction through a rider. The North Carolina General Assembly also passed comprehensive energy legislation North Carolina Senate Bill 3 (SB 3) in July 2007 that was signed into law by the Governor on August 20, 2007. Like the South Carolina legislation, the North Carolina legislation provides cost recovery assurance, subject to prudency review, for nuclear project development costs as well as baseload generation construction costs. A utility may include financing costs related to construction work in progress for baseload plants in a rate case.

William States Lee III Nuclear Station.

On December 12, 2007, Duke Energy Carolinas filed an application with the Nuclear Regulatory Commission (NRC), which has been docketed for review, for a combined Construction and Operating License (COL) for two Westinghouse AP1000 (advanced passive) reactors for the proposed William States Lee III Nuclear Station at a site in Cherokee County, South Carolina. Each reactor is capable of producing approximately 1,117 MW. Submitting the COL application does not commit Duke Energy Carolinas to build nuclear units. The NRC review of the COL application continues and the estimated receipt of the COL is in mid 2013. Duke Energy Carolinas filed with the U.S. Department of Energy (DOE) for a federal loan guarantee, which has the potential to significantly lower financing costs associated with the proposed William States Lee III Nuclear Station; however, it was not among the four projects selected by the DOE for the final phase of due diligence for the federal loan guarantee program. The project could be selected in the future if the program funding is expanded or if any of the current finalists drop out of the program.

Cliffside Unit 6.

On June 2, 2006, Duke Energy Carolinas filed an application with the NCUC for a Certificate of Public Convenience and Necessity (CPCN) to construct two 800 MW state of the art coal generation units at its existing Cliffside Steam Station in North Carolina. On March 21, 2007, the NCUC issued an Order allowing Duke Energy Carolinas to build one 800 MW unit. On February 20, 2008, Duke Energy Carolinas entered into an amended and restated engineering, procurement, construction and commissioning services agreement, valued at approximately $1.3 billion, with an affiliate of The Shaw Group, Inc., of which approximately $950 million relates to participation in the construction of Cliffside Unit 6, with the remainder related to a flue gas desulfurization system on an existing unit at

Cliffside. On February 27, 2009, Duke Energy Carolinas filed its latest updated cost estimate of $1.8 billion (excluding up to approximately $0.6 billion of allowance for funds used during construction (AFUDC)) for the approved new Cliffside Unit 6. Duke Energy Carolinas believes that the overall cost of Cliffside Unit 6 will be reduced by approximately $125 million in federal advanced clean coal tax credits. Construction of Cliffside Unit 6 is underway and is approximately 55% complete as of December 31, 2009.

Dan River and Buck Combined Cycle Facilities.

On June 29, 2007, Duke Energy Carolinas filed with the NCUC preliminary CPCN information to construct a 620 MW combined cycle natural gas-fired generating facility at its existing Dan River Steam Station, as well as updated preliminary CPCN information to construct a 620 MW combined cycle natural gas-fired generating facility at its existing Buck Steam Station. On December 14, 2007, Duke Energy Carolinas filed CPCN applications for the two combined cycle facilities. The NCUC consolidated its consideration of the two CPCN applications and held an evidentiary hearing on the applications on March 11, 2008. On May 5, 2008, Duke Energy Carolinas entered into an engineering, construction and commissioning services agreement for the Buck combined cycle project, valued at approximately $275 million, with Shaw North Carolina, Inc. On November 5, 2008, Duke Energy Carolinas notified the NCUC that since the issuance of the CPCN Order, recent economic factors have caused increased uncertainty with regard to forecasted load and near-term capital expenditures, resulting in a modification of the construction schedule. On September 1, 2009, Duke Energy Carolinas filed with the NCUC further information clarifying the construction schedule for the two projects. Under the revised schedule, the Buck Project is expected to begin operation in combined cycle mode by the end of 2011, but without a phased-in simple cycle commercial operation. The Dan River Project is expected to begin operation in combined cycle mode by the end of 2012, also without a phased-in simple cycle commercial operation. On December 21, 2009, Duke Energy Carolinas entered into a First Amended and Restated engineering, construction and commissioning services agreement with Shaw North Carolina, Inc. for $322 million which reflects the revised schedule. Based on the most updated cost estimates, total costs (including AFUDC) for the Buck and Dan River projects are approximately $660 million and $710 million, respectively.

On October 15, 2008, the Division of Air Quality (DAQ) issued a final air construction permit authorizing construction of the Buck combined cycle natural gas-fired generating units, and on August 24, 2009, the DAQ issued a final air permit authorizing construction of the Dan River combined cycle natural gas-fired generation units.

Edwardsport IGCC.

On September 7, 2006, Duke Energy Indiana and Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana (Vectren) filed a joint petition with the IURC seeking a CPCN for the construction of a 630 MW IGCC power plant at Duke Energy Indiana's Edwardsport Generating Station in Knox County, Indiana. The facility was initially estimated to cost approximately $2 billion (including approximately $120 million of AFUDC). In August 2007, Vectren formally withdrew its participation in the IGCC plant and a hearing was conducted on the CPCN petition based on Duke Energy Indiana owning 100% of the project. On November 20, 2007, the IURC issued an order granting Duke Energy Indiana a CPCN for the proposed IGCC Project, approved the cost estimate of $1.985 billion and approved the timely recovery of costs related to the project. On January 25, 2008, Duke Energy Indiana received the final air permit from the Indiana Department of Environmental Management.

On May 1, 2008, Duke Energy Indiana filed its first semi-annual IGCC Rider and ongoing review proceeding with the IURC as required under the CPCN Order issued by the IURC. In its filing, Duke Energy Indiana requested approval of a new cost estimate for the IGCC Project of $2.35 billion (including approximately $125 million of AFUDC) and for approval of plans to study carbon capture as required by the IURC's CPCN Order. On January 7, 2009, the IURC approved Duke Energy Indiana's request, including the new cost estimate of $2.35 billion, and cost recovery associated with a study on carbon capture. Duke Energy Indiana was required to file its plans for studying carbon storage related to the project within 60 days of the order. On November 3, 2008 and May 1, 2009, Duke Energy Indiana filed its second and third semi-annual IGCC riders, respectively, both of which were approved by the IURC in full.

On November 24, 2009, Duke Energy Indiana filed a petition for its fourth semi-annual IGCC rider and ongoing review proceeding with the IURC. Duke Energy has experienced design modifications and scope growth above what was anticipated from the preliminary engineering design, adding capital costs to the IGCC project. Duke Energy Indiana forecasted that the additional capital cost items would use the remaining contingency and escalation amounts in the current $2.35 billion cost estimate and add approximately $150 million, or about 6.4% to the total IGCC Project cost estimate, excluding the impact associated with the need to add more contingency. Duke Energy Indiana did not request approval of an increased cost estimate in the fourth semi-annual update proceeding; rather, Duke Energy Indiana requested the IURC to establish a subdocket proceeding in which Duke Energy will present additional evidence regarding an updated estimated cost for the IGCC project and in which a more comprehensive review of the IGCC project could occur. On January 27, 2010, the IURC approved Duke Energy Indiana's request for a subdocket proceeding regarding the cost estimate issues and accepted procedural schedules for the fourth semi-annual update proceeding and the subdocket proceeding. The evidentiary hearing for the fourth semi-annual update proceeding is scheduled for April 6, 2010. In the cost estimate subdocket proceeding, Duke Energy Indiana will be filing a new cost estimate for the IGCC project on April 7, 2010, with its case-in-chief testimony, and a hearing is scheduled to begin August 10, 2010. Duke Energy Indiana continues to work with its vendors to update and refine the forecasted increased cost to complete the Edwardsport IGCC project, and currently anticipates that the total cost increase it submits in the cost estimate subdocket proceeding will be significantly higher than the $150 million previously identified.

Duke Energy Indiana filed a petition with the IURC requesting approval of its plans for studying carbon storage, sequestration and/or enhanced oil recovery for the carbon dioxide (CO_2) from the

Edwardsport IGCC facility on March 6, 2009. On July 7, 2009, Duke Energy Indiana filed its case-in-chief testimony requesting approval for cost recovery of a $121 million site assessment and characterization plan for CO_2 sequestration options including deep saline sequestration, depleted oil and gas sequestration and enhanced oil recovery for the CO_2 from the Edwardsport IGCC facility. The Indiana Office of Utility Consumer Counselor (OUCC) filed testimony supportive of the continuing study of carbon storage, but recommended that Duke Energy Indiana break its plan into phases, recommending approval of only approximately $33 million in expenditures at this time and deferral of expenditures rather than cost recovery through a tracking mechanism as proposed by Duke Energy Indiana. Intervenor CAC recommended against approval of the carbon storage plan stating customers should not be required to pay for research and development costs. Duke Energy Indiana's rebuttal testimony was filed October 30, 2009, wherein it amended its request to seek deferral of approximately $42 million to cover the carbon storage site assessment and characterization activities scheduled to occur through approximately the end of 2010, with further required study expenditures subject to future IURC proceedings. An evidentiary hearing was held on November 9, 2009, and an order is expected in the first half of 2010.

Under the Edwardsport IGCC CPCN order and statutory provisions, Duke Energy Indiana is entitled to recover the costs reasonably incurred in reliance on the CPCN Order. In December 2008, Duke Energy Indiana entered into a $200 million engineering, procurement and construction management agreement with Bechtel Power Corporation. Construction of Edwardsport is underway and is approximately 50% complete as of December 31, 2009.

See Note 4 to the Consolidated Financial Statements, "Regulatory Matters," for further discussion on the above in-process or potential construction projects.

Fuel Supply

U.S. Franchised Electric and Gas relies principally on coal and nuclear fuel for its generation of electric energy. The following table lists U.S. Franchised Electric and Gas' sources of power and fuel costs for the three years ended December 31, 2009.

	Generation by Source (Percent)			Cost of Delivered Fuel per Net Kilowatt-hour Generated (Cents)		
	2009	2008	2007	**2009**	2008	2007
Coal[a]	**59.6**	66.9	66.5	**2.88**	2.59	2.20
Nuclear[b]	**38.5**	32.1	31.2	**0.48**	0.44	0.38
Oil and gas[c]	**0.4**	0.7	1.1	**7.71**	13.47	9.32
All fuels (cost-based on weighted average)[a][b]	**98.5**	99.7	98.8	**1.96**	1.97	1.71
Hydroelectric[d]	**1.5**	0.3	1.2			
	100.0	100.0	100.0			

(a) Statistics related to coal generation and all fuels reflect U.S. Franchised Electric and Gas' 69% ownership interest in the East Bend Steam Station and 50.05% ownership interest in Unit 5 of the Gibson Steam Station.
(b) Statistics related to nuclear generation and all fuels reflect U.S. Franchised Electric and Gas' 12.5% interest in the Catawba Nuclear Station through September 30, 2008 and an approximate 19% ownership interest in the Catawba Nuclear Station from October 1, 2008 and thereafter.
(c) Cost statistics include amounts for light-off fuel at U.S. Franchised Electric and Gas' coal-fired stations.
(d) Generating figures are net of output required to replenish pumped storage facilities during off-peak periods.

Coal.

U.S. Franchised Electric and Gas meets its coal demand in the Carolinas and Midwest through a portfolio of purchase supply contracts and spot agreements. Large amounts of coal are purchased under supply contracts with mining operators who mine both underground and at the surface. U.S. Franchised Electric and Gas uses spot-market purchases to meet coal requirements not met by supply contracts. Expiration dates for its supply contracts, which have various price adjustment provisions and market re-openers, range from 2010 to 2014. U.S. Franchised Electric and Gas expects to renew these contracts or enter into similar contracts with other suppliers for the quantities and quality of coal required as existing contracts expire, though prices will fluctuate over time as coal markets change. The coal purchased for the Carolinas is primarily produced from mines in eastern Kentucky, West Virginia and southwestern Virginia. The coal purchased for the regulated Midwest entities is primarily produced in Indiana, Illinois, and Kentucky. U.S. Franchised Electric and Gas has an adequate supply of coal under contract to fuel its projected 2010 operations and a significant portion of supply to fuel its projected 2011 operations.

The current average sulfur content of coal purchased by U.S. Franchised Electric and Gas for the Carolinas is approximately 1%; however, as Carolinas coal plants continue to bring on scrubbers over the next several years, the sulfur content of coal purchased could increase as higher sulfur coal options are considered. The current average sulfur content of coal purchased by U.S. Franchised Electric and Gas for the Midwest is approximately 2%. Coupled with the use of available sulfur dioxide (SO_2) emission allowances on the open market, this satisfies the current emission limitations for SO_2 for existing facilities in the Carolinas and Midwest.

Gas.

U.S. Franchised Electric and Gas is responsible for the purchase and the subsequent delivery of natural gas to native load customers in its Ohio and Kentucky service territories. U.S. Franchised Electric and Gas' natural gas procurement strategy is to buy firm natural gas supplies (natural gas intended to be available at all times) and firm interstate pipeline transportation capacity during the winter season (November through March) and during the non-heating season (April through October) through a combination of firm supply and transportation capacity along with spot supply and interruptible transportation capacity. This strategy allows U.S. Franchised Electric and Gas to assure reliable natural gas supply for its high priority (non-curtailable) firm customers during peak winter conditions and provides U.S. Franchised Electric and Gas the flexibility to reduce its contract commitments if firm customers choose alternate gas suppliers under U.S. Franchised Electric and Gas' customer choice/gas transportation programs. In 2009, firm supply purchase commitment agreements provided approximately 99% of the natural gas supply, with the remaining gas purchased on the spot market. These firm supply agreements feature two levels of gas supply, specifically (1) base load, which is a continuous supply to meet normal demand requirements, and (2) swing load, which is gas available on a daily basis to accommodate changes in demand due primarily to changing weather conditions.

U.S. Franchised Electric and Gas also owns two underground caverns with a total storage capacity of approximately 16 million gallons of liquid propane. In addition, U.S. Franchised Electric and Gas has access to 5.5 million gallons of liquid propane storage and product loan through a commercial services agreement with a third party. This liquid propane is used in the three propane/air peak shaving plants located in Ohio and Kentucky. Propane/air peak shaving plants vaporize the propane and mix with natural gas to supplement the natural gas supply during peak demand periods and emergencies.

U.S. Franchised Electric and Gas manages natural gas procurement-price volatility mitigation programs for Duke Energy Ohio and Duke Energy Kentucky. These programs pre-arrange between 10-25% of total winter heating season gas requirements for Duke Energy Ohio, between 10-35% of total winter heating season gas requirements for Duke Energy Kentucky and between 10-50% of total summer season gas requirements for both Duke Energy Ohio and Duke Energy Kentucky for up to three years in advance of the delivery month. Duke Energy Ohio and Duke Energy Kentucky use primarily fixed-price forward contracts and contracts with a ceiling and floor on the price. As of December 31, 2009, Duke Energy Ohio and Duke Energy Kentucky, combined, had locked in pricing for approximately 22% of their winter 2009/2010 system load requirements.

U.S. Franchised Electric and Gas is also responsible for the purchase and the subsequent delivery of natural gas to the gas turbine generators to serve native electric load customers in the Duke Energy Carolinas, Duke Energy Indiana and Duke Energy Kentucky service territories. The natural gas procurement strategy is to contract with one or several suppliers who buy spot market natural gas supplies along with firm or interruptible interstate pipeline transportation capacity for deliveries to the site. This strategy allows for competitive pricing, flexibility of delivery, and reliable natural gas supplies to each of the natural gas plants. Many of the natural gas plants can be served by several supply zones and multiple pipelines.

Duke Energy Indiana hedges a percentage of its winter and summer expected native gas burn from Indiana gas turbine units using financial swaps tied to the New York Mercantile Exchange (NYMEX)-Henry Hub natural gas futures.

Nuclear.

The industrial processes for producing nuclear generating fuel generally involve the mining and milling of uranium ore to produce uranium concentrates, the services to convert uranium concentrates to uranium hexafluoride, the services to enrich the uranium hexafluoride, and the services to fabricate the enriched uranium hexafluoride into usable fuel assemblies.

Duke Energy Carolinas has contracted for uranium materials and services to fuel the Oconee, McGuire and Catawba Nuclear Stations in the Carolinas. Uranium concentrates, conversion services and enrichment services are primarily met through a diversified portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. Duke Energy Carolinas staggers its contracting so that its portfolio of long-term contracts covers the majority of its fuel requirements at Oconee, McGuire and Catawba in the near-term and decreasing portions of its fuel requirements over time thereafter. Due to the technical complexities of changing suppliers of fuel fabrication services, Duke Energy Carolinas generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Duke Energy Carolinas has entered into fuel contracts that, based on its current need projections, cover 100% of the uranium concentrates, conversion services, and enrichment services requirements of the Oconee, McGuire and Catawba Nuclear Stations through at least 2011 and cover fabrication services requirements for these plants through at least 2018. For subsequent years, a portion of the fuel requirements at Oconee, McGuire and Catawba are covered by long-term contracts. For future requirements not already covered under long-term contracts, Duke Energy Carolinas believes it will be able to renew contracts as they expire, or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with uranium spot market purchases.

Energy Efficiency.

Several factors have led to increased focus on energy efficiency, including environmental constraints, increasing costs of generating plans and legislative mandates regarding building codes and appliance efficiencies. As a result of these factors, Duke Energy has developed various programs designed to promote the efficient use of electricity by its customers. These programs, collectively called save-a-watt, have been filed with various state commissions over the past several years.

Save-a-watt was approved by the PUCO on December 17, 2008, in conjunction with the ESP, and Duke Energy Ohio began offering programs and billing a rate rider effective January 1, 2009. Save-a-watt is approved to continue through December 31, 2011.

On February 26, 2009, the NCUC approved Duke Energy Carolinas' energy efficiency programs and authorized Duke Energy Carolinas to implement its rate rider pending approval of a final compensation mechanism by the NCUC. Duke Energy Carolinas began offering energy conservation programs to North Carolina retail customers and billing a conservation-program only rider on June 1, 2009. In October 2009, Duke Energy Carolinas also began offering demand response programs in North Carolina. On December 14, 2009, the NCUC approved the save-a-watt compensation model and, effective January 1, 2010, Duke Energy Carolinas began billing a rate rider reflecting both conservation and demand response programs. The save-a-watt programs and compensation approach in North Carolina are approved through December 31, 2013.

Duke Energy Carolinas began offering demand response and conservation programs to South Carolina retail customers effective June 1, 2009. On January 20, 2010, the PSCSC approved a save-a-watt rider for Duke Energy Carolinas' energy efficiency programs. Duke Energy Carolinas began billing this rider to retail customers February 1, 2010. The save-a-watt programs and compensation approach in South Carolina are approved through December 31, 2013.

In October 2007, Duke Energy Indiana filed its petition with the IURC requesting approval of save-a-watt. Duke Energy Indiana reached a settlement with all intervenors except one, the CAC, and filed the settlement agreement with the IURC. An evidentiary hearing with the IURC was held on February 27, 2009 and March 2, 2009. On February 10, 2010, the IURC approved the request.

The KPSC approved Duke Energy Kentucky's current energy efficiency programs in 2009. The KPSC is reviewing Duke Energy Kentucky's proposed adjustment for 2010 and a decision is expected by May 2010. On December 1, 2008, Duke Energy Kentucky filed an application for the save-a-watt compensation model. On January 27, 2010, Duke Energy Kentucky withdrew the application to implement save-a-watt and plans to file a revised portfolio in the future.

SmartGrid and Distributed Renewable Generation Demonstration Project.

Duke Energy Indiana filed a petition in May 2008, and case-in-chief testimony in September 2008, supporting its request to build an intelligent distribution grid in Indiana. The proposal requested approval of distribution formula rates or, in the alternative, a SmartGrid Rider to recover the return on and of the capital costs of the build-out and the recovery of incremental operating and maintenance expenses and lost revenues. The petition also included a pilot program for the installation of small solar photovoltaic and wind generation on customer sites, for approximately $10 million over a three-year period. Duke Energy Indiana filed supplemental testimony in January 2009 to reflect the impacts of new favorable tax treatment on the cost/benefit analysis for SmartGrid. After various filings by interveners, on June 4, 2009, Duke Energy Indiana filed with the IURC a settlement agreement with the OUCC, the CAC, Nucor Corporation, and the Duke Energy Indiana Industrial Group which provided for a full deployment of Duke Energy Indiana's SmartGrid initiative at a slower pace, including cost recovery through a tracking mechanism. The settlement also included increased reporting and monitoring requirements, approval of Duke Energy Indiana's renewable distributed generation pilot and the creation of a collaborative design to initiate several time differentiated pricing pilots, an electric vehicle pilot and a home area network pilot. Additionally, the settlement agreement provided for tracker recovery of the costs associated with the SmartGrid initiative, subject to cost recovery caps and a termination date for the tracker. The tracker would also include a reduction in costs associated with the adoption of a new depreciation study. An evidentiary hearing was held on June 29, 2009. On November 4, 2009, the IURC issued an order that rejected the settlement agreement as incomplete and not in the public interest. The IURC cited a lack of defined benefits of the programs and encouraged the parties to continue the collaborative process outlined in the settlement or to consider smaller scale pilots or phased-in options. The IURC required the parties to present a procedural schedule within 10 days to address the underlying relief requested in the cause, and to supplement the record to address issues regarding the American Recovery and Reinvestment Act (the Stimulus Bill) funding recently awarded by the DOE. Duke Energy Indiana is considering its next steps, including a review of the implications of this Order on the Stimulus Bill SmartGrid Investment Grant award from the DOE. A technical conference was held at the IURC on December 1, 2009, wherein a procedural schedule was established for the IURC's continuing review of Duke Energy Indiana's smart grid proposal. Duke Energy is currently scheduled to file supplemental testimony in support of a revised SmartGrid proposal by April 1, 2010, with an evidentiary hearing scheduled for May 5, 2010.

Duke Energy Ohio received approval to recover expenditures incurred to deploy the SmartGrid infrastructure in December 2008 in conjunction with the approval of Duke Energy Ohio's ESP filing. On June, 30, 2009, Duke Energy Ohio filed an application to establish rates for return of its SmartGrid net costs incurred for gas and electric distribution service through the end of 2008. Duke Energy Ohio proposed its gas SmartGrid rider as part of its most recent gas distribution rate case. A Stipulation and Recommendation was entered into by Duke Energy Ohio, Staff of the PUCO, Kroger Company, and Ohio Partners for Affordable Energy, which provides for a revenue increase of approximately $4.2 million under the electric rider and $590,000 under the natural gas rider. Approval of the Stipulation and Recommendation is expected in the first quarter 2010.

Duke Energy Business Services, on behalf of Duke Energy Indiana and Duke Energy Ohio, was awarded a $200 million SmartGrid investment grant from the DOE in October 2009. Duke Energy is currently evaluating the terms and conditions of the grant in conjunction with regulatory activities described above that are ongoing in Indiana and Ohio.

See Note 4 to the Consolidated Financial Statements, "Regulatory Matters," for additional information.

Renewable Energy.

Climate change concerns, as well as the oil price volatility, have sparked rising government support in driving increasing renewable energy legislation at both the federal and state level. For example, as discussed further below, the North Carolina legislation (SB 3) passed in 2007 established a renewable energy and energy efficiency portfolio standard (REPS) for electric utilities, and in 2008, the state of Ohio also passed legislation that included renewable energy and advanced energy targets. Duke Energy Carolinas, Duke Energy Ohio and Duke Energy Indiana have issued Request for Proposals (RFP) seeking bids for power generated from renewable energy sources, including sun, wind, water, organic matter and other sources.

With the passage of Senate Bill 221 (SB 221) in Ohio in 2008, Duke Energy Ohio is required to secure renewable energy and include an increasing percentage of renewables as part of its resource portfolio. The compliance percentages are based on a three-year historical average of its standard service offer load. The requirements are 0.25% of the baseline load from non-solar and 0.004% from solar beginning in 2009, increasing to 12.5% non-solar and 0.5% solar by 2024. Of these percentages, at least 50% of each resource type must come from resources located within the state of Ohio. To address this legislation, Duke Energy Ohio initiated several acquisition activities including comprehensive renewable RFPs in June 2008. Duke Energy Ohio evaluated the bids and selected both solar and non-solar bids to begin negotiations aimed toward final contract executions. Initial objectives were focused on meeting the specific near-term 2009, 2010 and 2011 requirements. Duke Energy Ohio is also working with regulators to seek clarifications on points of the SB 221 renewable guidelines. Effective December 10, 2009, the PUCO adopted a set of reporting standards known as "Green Rules" which will regulate energy efficiency, alternative energy generation requirements and emission reporting for activities mandated by SB 221. Duke Energy Ohio will continue its renewable efforts with bidders, suppliers and the community in Ohio to meet the increasing renewable obligations.

With the passage of SB 3 in North Carolina in 2007, Duke Energy Carolinas was required to include an increasing percentage of renewables as part of its generation portfolio. SB 3 requires solar compliance at 0.02% of retail sales beginning in 2010 and 3% of total portfolio to comply with solar, swine and poultry requirements beginning 2012. Total North Carolina renewable energy resource compliance increases to 12.5% by 2021. SB 3 granted the NCUC authority to approve an energy efficiency rate rider to compensate utilities for new energy efficiency programs that they implement, as well as a REPS rider to recover incremental costs incurred to comply with the renewable portfolio standard. To address this legislation, Duke Energy Carolinas initiated a comprehensive renewable RFP in April 2007 to address the 2010 through 2014 renewable portfolio standards requirements. As a result of the 2007 renewable energy RFP, Duke Energy Carolinas has executed a contract with a solar bidder and several landfill gas contracts which will be added to the hydro facilities portfolio to meet future compliance requirements. Duke Energy Carolinas is working with regulators to seek clarifications on points of the SB 3 renewable guidelines. Duke Energy Carolinas will continue to meet its growing renewable efforts with bidders, suppliers and the community in the Carolinas to meet the increasing renewable obligations.

Inventory

Generation of electricity is capital-intensive. U.S. Franchised Electric and Gas must maintain an adequate stock of fuel, materials and supplies in order to ensure continuous operation of generating facilities and reliable delivery to customers. As of December 31, 2009, the inventory balance for U.S. Franchised Electric and Gas was approximately $1,278 million. See Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," for additional information.

Nuclear Insurance and Decommissioning

Duke Energy Carolinas owns and operates the McGuire and Oconee Nuclear Stations and operates and has a partial ownership interest in the Catawba Nuclear Station. The McGuire and the Catawba Nuclear Stations each have two nuclear reactors and the Oconee Nuclear Station has three. Nuclear insurance includes: liability coverage; property, decontamination and premature decommissioning coverage; and business interruption and/or extra expense coverage. The other joint owners of the Catawba Nuclear Station reimburse Duke Energy Carolinas for certain expenses associated with nuclear insurance premiums. The Price-Anderson Act requires Duke Energy to provide for public liability claims resulting from nuclear incidents to the maximum total financial protection liability, which was approximately $12.5 billion and increased to approximately $12.6 billion effective January 1, 2010. See Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies — Nuclear Insurance," for more information.

In 2005, the NCUC and PSCSC approved a $48 million annual amount for contributions and expense levels for decommissioning. In each of the years ended December 31, 2009, 2008 and 2007, Duke Energy Carolinas expensed approximately $48 million and contributed cash of approximately $48 million to the Nuclear Decommissioning Trust Funds (NDTF) for decommissioning costs. The entire amount of these contributions were to the funds reserved for contaminated costs as contributions to the funds reserved for non-contaminated costs have been discontinued since the current estimates indicate existing funds to be sufficient to cover projected future costs. The balance of the external NDTF was approximately $1,765 million as of December 31, 2009 and $1,436 million as of December 31, 2008.

As the NCUC and the PSCSC require that Duke Energy Carolinas update its cost estimate for decommissioning its nuclear plants every five years, new site-specific nuclear decommissioning cost studies were completed in January 2009 that showed total estimated nuclear decommissioning costs, including the cost to decommission plant components not subject to radioactive contamination, of approximately $3 billion in 2008 dollars. This estimate includes Duke Energy Carolinas' 19.25% ownership interest in the Catawba Nuclear Station. The other joint owners of the Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. Both the NCUC and the PSCSC have allowed Duke Energy Carolinas to recover estimated decommissioning costs through retail rates over the expected remaining service periods of Duke Energy Carolinas' nuclear stations. Duke Energy Carolinas believes that the decommissioning costs being recovered through rates, when coupled with the existing fund balance and expected fund earnings, will be sufficient to provide for the cost of future decommissioning.

Duke Energy Carolinas filed these site-specific nuclear decommissioning cost studies with the NCUC and the PSCSC in April 2009. In addition to the decommissioning cost studies, a new funding study was completed and indicates the current annual funding requirement of approximately $48 million is sufficient to cover the estimated decommissioning costs. Duke Energy Carolinas received an order from the NCUC on its rate case filing on

December 7, 2009, and from the PSCSC on Duke Energy Carolinas' rate case on January 27, 2010. Both the NCUC and the PSCSC approved the existing $48 million annual funding level for nuclear decommissioning costs. See Note 7 to the Consolidated Financial Statements, "Asset Retirement Obligations," for more information.

After used fuel is removed from a nuclear reactor, it is cooled in a spent-fuel pool at the nuclear station. Under provisions of the Nuclear Waste Policy Act of 1982, Duke Energy Carolinas contracted with the DOE for the disposal of used nuclear fuel. The DOE failed to begin accepting used nuclear fuel on January 31, 1998, the date specified by the Nuclear Waste Policy Act and in Duke Energy's contract with the DOE. Duke Energy Carolinas will continue to safely manage its used nuclear fuel until the DOE accepts it. In 1998, Duke Energy Carolinas filed a claim with the U.S. Court of Federal Claims against the DOE related to the DOE's failure to accept commercial used nuclear fuel by the required date. Damages claimed in the lawsuit were based upon Duke Energy Carolinas' costs incurred as a result of the DOE's partial material breach of its contract, including the cost of securing additional used fuel storage capacity. On March 5, 2007, Duke Energy Carolinas and the U.S. Department of Justice reached a settlement resolving Duke Energy Carolinas' used nuclear fuel litigation against the DOE. The agreement provided for an initial payment to Duke Energy Carolinas for certain storage costs incurred through July 31, 2005, with additional amounts reimbursed annually for future storage costs.

Asbestos Related Injuries and Damages Claims

Duke Energy has experienced numerous claims for indemnification and medical reimbursements relating to damages for bodily injuries alleged to have arisen from the exposure to or use of asbestos in connection with construction and maintenance activities conducted by Duke Energy Carolinas on its electric generation plants prior to 1985.

Duke Energy has third-party insurance to cover certain losses related to Duke Energy Carolinas' asbestos-related injuries and damages above an aggregate self insured retention of $476 million. Reserves recorded on Duke Energy's Consolidated Balance Sheets are based upon the minimum amount in Duke Energy's best estimate of the range of loss for current and future asbestos claims through 2027. Management believes that it is possible there will be additional claims filed against Duke Energy Carolinas after 2027. In light of the uncertainties inherent in a longer-term forecast, management does not believe they can reasonably estimate the indemnity and medical costs that might be incurred after 2027 related to such potential claims. Asbestos-related loss estimates incorporate anticipated inflation, if applicable, and are recorded on an undiscounted basis. These reserves are based upon current estimates and are subject to greater uncertainty as the projection period lengthens. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change management's estimated liability, as could any substantial adverse or favorable verdict at trial. A federal legislative solution, further state tort reform or structured settlement transactions could also change the estimated liability. Given the uncertainties associated with projecting matters into the future and numerous other factors outside Duke Energy's control, management believes it is reasonably possible that Duke Energy Carolinas may incur asbestos liabilities in excess of its recorded reserves.

Duke Energy Indiana and Duke Energy Ohio have also been named as defendants or co-defendants in lawsuits related to asbestos at their electric generating stations. The impact on Duke Energy's consolidated results of operations, cash flows, or financial position of these cases to date has not been material. Based on estimates under varying assumptions, concerning uncertainties, such as, among others: (i) the number of contractors potentially exposed to asbestos during construction or maintenance of Duke Energy Indiana and Duke Energy Ohio generating plants; (ii) the possible incidence of various illnesses among exposed workers and (iii) the potential settlement costs without federal or other legislation that addresses asbestos tort actions, Duke Energy estimates that the range of reasonably possible exposure in existing and future suits over the foreseeable future is not material. This estimated range of exposure may change as additional settlements occur and claims are made and more case law is established.

See Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies-Litigation-Asbestos Related Injuries and Damages Claims," for more information.

Competition

U.S. Franchised Electric and Gas competes in some areas with government-owned power systems, municipally owned electric systems, rural electric cooperatives and other private utilities. By statute, the NCUC and the PSCSC assign service areas outside municipalities in North Carolina and South Carolina, respectively, to regulated electric utilities and rural electric cooperatives. Substantially all of the territory comprising Duke Energy Carolinas' service area has been assigned in this manner. In unassigned areas, Duke Energy Carolinas' business remains subject to competition. A decision of the North Carolina Supreme Court limits, in some instances, the right of North Carolina municipalities to serve customers outside their corporate limits. In South Carolina, competition continues between municipalities and other electric suppliers outside the municipalities' corporate limits, subject to the regulation of the PSCSC. In Kentucky, the right of municipalities to serve customers outside corporate limits is subject to court approval. In Ohio, certified suppliers may offer retail electric generation service to residential, commercial and industrial customers. In Indiana, the state is divided into certified electric service areas for municipal utilities, rural cooperatives and investor owned utilities. There are limited circumstances where the certified electric service areas can be modified, with approval of the IURC. U.S. Franchised Electric and Gas also competes with other utilities and marketers in the wholesale electric business. In addition, U.S. Franchised Electric and Gas continues to compete with natural gas providers.

Regulation

State

The NCUC, the PSCSC, the PUCO, the IURC and the KPSC (collectively, the State Utility Commissions) approve rates for retail electric service within their respective states. In addition, the PUCO and the KPSC approve rates for retail gas distribution service within their respective states. The FERC approves U.S. Franchised Electric and Gas' cost-based rates for electric sales to certain wholesale customers. The State Utility Commissions, except for the PUCO, also have authority over the construction and operation of U.S. Franchised Electric and Gas' generating facilities. CPCN's issued by the State Utility Commissions, as applicable, authorize U.S. Franchised Electric and Gas to construct and operate its electric facilities, and to sell electricity to retail and wholesale customers. Prior approval from the relevant State Utility Commission is required for Duke Energy's regulated operating companies to issue securities.

Duke Energy Carolinas 2009 North Carolina Rate Case.

On June 2, 2009, Duke Energy Carolinas filed an Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina to increase its base rates. The Application was based upon a historical test year consisting of the 12 months ended December 31, 2008. On October 20, 2009, Duke Energy Carolinas entered into a settlement agreement with the North Carolina Public Staff. Two organizations representing industrial customers joined the settlement on October 21, 2009. The terms of the agreement include a base rate increase of $315 million (or approximately 8%) phased in primarily over a two-year period beginning January 1, 2010. In order to mitigate the impact of the increase on customers, the agreement provides for (i) a one-year delay in the collection of financing costs related to the Cliffside modernization project until January 1, 2011; and (ii) the accelerated return of certain regulatory liabilities to customers which lowered the total impact to customer bills to an increase of approximately 7% in the near-term. The proposed settlement includes a 10.7% return on equity and a capital structure of 52.5% equity and 47.5% long-term debt. Additionally, Duke Energy Carolinas agreed not to file another rate case before 2011 with any changes to rates taking effect no sooner than 2012. The NCUC approved the settlement agreement in full by order dated December 7, 2009. The new rates were effective and implemented on January 1, 2010.

Duke Energy Carolinas 2009 South Carolina Rate Case.

On July 27, 2009, Duke Energy Carolinas filed its Application for Authority to Increase and Adjust Rates and Charges for an increase in rates and charges in South Carolina. On September 25, 2009, Duke Energy Carolinas filed a supplemental request seeking PSCSC approval of a charge to customer bills to pay for Duke Energy Carolinas' new energy efficiency efforts. Parties to the proceeding include the South Carolina Office of Regulatory Staff (ORS), the South Carolina Energy Users Committee (SCEUC), and the South Carolina Green Party. Duke Energy Carolinas, ORS, and SCEUC filed a settlement agreement on November 24, 2009, recommending, (i) a $74 million increase in base rates, (ii) an allowed return on equity of 11% with rates set at a return on equity of 10.7% and capital structure of 53% equity, and (iii) various riders, including one that provides for the return of DSM charges previously collected from customers over three years rather than five years, and another that provides for a storm reserve provision allowing Duke Energy Carolinas to collect $5 million annually (up to a maximum funding level of $50 million accumulating in reserves) to be used against large storm costs in any particular period. On January 20, 2010, the PSCSC approved the settlement agreement in full, including the cost recovery mechanism for the energy efficiency effort. The new rates were effective February 1, 2010.

Duke Energy Ohio Electric Rate Filings.

New legislation (SB 221) passed in April 2008 and signed by the Governor of Ohio on May 1, 2008 codified the PUCO's authority to approve an electric utility's standard generation service offer through an ESP, which allows for pricing structures similar to those under the historic RSP. Electric utilities are required to file an ESP and may also file an application for a Market Rate Option (MRO) at the same time. The MRO is a price determined through a competitive bidding process. On July 31, 2008, Duke Energy Ohio filed an ESP to be effective January 1, 2009. On December 17, 2008, the PUCO issued its finding and order adopting a modified Stipulation with respect to Duke Energy Ohio's ESP filing. The PUCO agreed to Duke Energy Ohio's request for a net increase in base generation revenues, before impacts of customer switching, of $36 million, $74 million and $98 million in 2009, 2010 and 2011, respectively, including the termination of the residential and non-residential Regulatory Transition Charge, the recovery of expenditures incurred to deploy the SmartGrid infrastructure and the implementation of save-a-watt. See "Commercial Power" section below for additional information related to the ESP.

For more information on rate matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters — U.S. Franchised Electric and Gas."

Federal

Regulations of FERC and the State Utility Commissions govern access to regulated electric and gas customer and other data by non-regulated entities, and services provided between regulated and non-regulated energy affiliates. These regulations affect the activities of non-regulated affiliates with U.S. Franchised Electric and Gas.

The Energy Policy Act of 2005 was signed into law in August 2005. The legislation directs specified agencies to conduct a significant number of studies on various aspects of the energy industry and to implement other provisions through rule makings. Among the key provisions, the Energy Policy Act of 2005 repealed the Public Utility Holding Company Act (PUHCA) of 1935, directed FERC to establish a self-regulating electric reliability organization governed by an independent board with FERC oversight, extended the Price Anderson Act for 20 years (until 2025), provided loan guarantees, standby support and production tax credits for new nuclear reactors, gave FERC enhanced merger approval authority, provided FERC new backstop authority for the siting of certain electric transmission projects, streamlined the processes for approval and permitting of interstate pipelines, and reformed hydropower relicensing. In 2005 and 2006, FERC initiated several rule makings as directed by the Energy Policy Act of 2005. These rulemakings have now been completed, subject to certain appeals and further proceeding. Duke Energy does not believe that these rulemakings or the appeals will have a material adverse effect on its consolidated results of operations, cash flows or financial position.

The Energy Policy Act of 1992 and subsequent rulemakings and events initiated the opening of wholesale energy markets to competition. Open access transmission for wholesale transmission provides energy suppliers and load serving entities, including U.S. Franchised Electric and Gas and wholesale customers located in the U.S. Franchised Electric and Gas service area, with opportunities to purchase, sell and deliver capacity and energy at market-based prices, which can lower overall costs to retail customers.

Duke Energy Ohio, Duke Energy Kentucky and Duke Energy Indiana are transmission owners in a regional transmission organization operated by the Midwest Independent Transmission System Operator, Inc. (Midwest ISO), a non-profit organization which maintains functional control over the combined transmission systems of its members. In 2005, the Midwest ISO began administering an energy market within its footprint and in January 2009 it began administering an ancillary services market. Additionally, in April 2009, the Midwest ISO began administering a voluntary capacity auction, and in June 2009, instituted a tariff based capacity requirement.

On December 17, 2001, the IURC approved the transfer of functional control of the operation of the Duke Energy Indiana transmission system to the Midwest ISO, a Regional Transmission Organization (RTO) established in 1998. On June 1, 2005, the IURC authorized Duke Energy Indiana to transfer control area operations tasks and responsibilities and transfer dispatch and Day 2 energy markets tasks and responsibilities to the Midwest ISO. On August 13, 2008, the IURC authorized Duke Energy Indiana to transfer additional balancing authority functions to the Midwest ISO to permit Duke Energy Indiana to participate in the Midwest ISO's ancillary services market.

The Midwest ISO is the provider of transmission service requested on the transmission facilities under its tariff. It is responsible for the reliable operation of those transmission facilities and the regional planning of new transmission facilities. The Midwest ISO administers energy markets utilizing Locational Marginal Pricing (i.e., the energy price for the next MW may vary throughout the Midwest ISO market based on transmission congestion and energy losses) as the methodology for relieving congestion on the transmission facilities under its functional control.

On December 19, 2005, the FERC approved a plan filed by Duke Energy Carolinas to establish an "Independent Entity" (IE) to serve as a coordinator of certain transmission functions and an "Independent Monitor" (IM) to monitor the transparency and fairness of the operation of Duke Energy Carolinas' transmission system. Duke Energy Carolinas remains the owner and operator of the transmission system, with responsibility for the provision of transmission service under Duke Energy Carolinas' Open Access Transmission Tariff. Duke Energy Carolinas retained the Midwest ISO to act as the IE and Potomac Economics, Ltd. to act as the IM. The IE and IM began operations on November 1, 2006. Duke Energy Carolinas is not currently seeking adjustments to its transmission rates to reflect the incremental cost of the proposal, which is not projected to have a material adverse effect on Duke Energy's future consolidated results of operations, cash flows or financial position.

See "Other Issues" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion about potential Global Climate Change legislation and the potential impacts such legislation could have on Duke Energy's operations.

Other

U.S. Franchised Electric and Gas is subject to the jurisdiction of the NRC for the design, construction and operation of its nuclear generating facilities. In 2000, the NRC renewed the operating license for Duke Energy Carolinas' three Oconee nuclear units through 2033 for Units 1 and 2 and through 2034 for Unit 3. In 2003, the NRC renewed the operating licenses for all units at Duke Energy Carolinas' McGuire and Catawba stations. The two McGuire units are licensed through 2041 and 2043, respectively, while the two Catawba units are licensed through 2043. All but one of U.S. Franchised Electric and Gas' hydroelectric generating facilities are licensed by the FERC under Part I of the Federal Power Act, with license terms expiring from 2005 to 2036. The FERC has authority to issue new hydroelectric generating licenses. Hydroelectric facilities whose licenses expired in 2005 through 2009 are operating under annual extensions of the current license until FERC issues a new license. Other hydroelectric facilities whose licenses expire between 2010 and 2016 are in various stages of relicensing. Duke Energy expects to receive new licenses for all applicable hydroelectric facilities with the exception of the Dillsboro Project, for which Duke Energy requested and the FERC approved license surrender. Duke Energy Carolinas has removed the Dillsboro Project dam and powerhouse as part of multi-project and multi-stakeholder agreements and Duke Energy Carolinas is continuing with stream restoration and post-removal monitoring as requested by FERC's license surrender order.

U.S. Franchised Electric and Gas is subject to the jurisdiction of the U.S. Environmental Protection Agency (EPA) and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

COMMERCIAL POWER

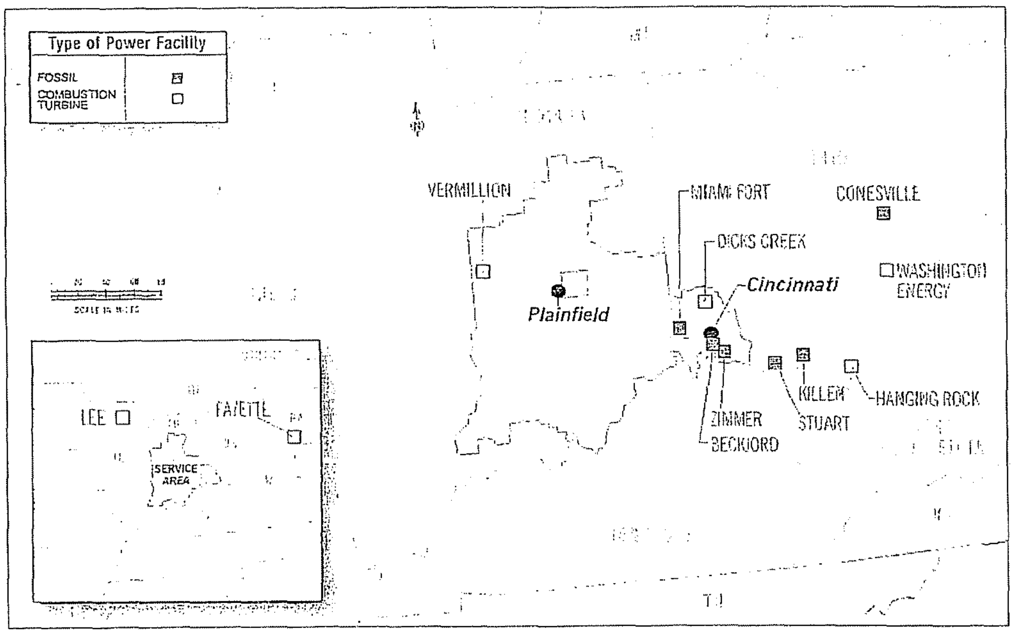
Commercial Power owns, operates and manages power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants as well as other contractual positions. Commercial Power's generation asset fleet consists of Duke Energy Ohio's non-regulated generation in Ohio, acquired from Cinergy in April 2006, which are dedicated under the ESP, and the five Midwestern gas-fired non-regulated generation assets that were a portion of former DENA, which are dispatched into wholesale markets. Commercial Power's assets, excluding wind energy generation assets, are comprised of approximately 7,550 net

MW of power generation primarily located in the Midwestern United States. The asset portfolio has a diversified fuel mix with baseload and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units. Effective January 1, 2009, approximately half of Commercial Power's Ohio-based generation assets began operating under an ESP, which expires on December 31, 2011, and is described below. Prior to January 1, 2009, these generation assets were contracted through the RSP, which expired on December 31, 2008.

Commercial Power also has a retail sales subsidiary, DERS, which is certified by the PUCO as a CRES provider in Ohio. DERS serves retail electric customers in Southwest, West Central and Northern Ohio with generation and other energy services at competitive rates. During 2009, due to increased levels of customer switching as a result of the competitive markets in Ohio, which is discussed further below, DERS has focused on acquiring customers that had previously been served by Duke Energy Ohio under the ESP, as well as those previously served by other Ohio franchised utilities.

The following map shows the Commercial Power service territory and generation facilities.

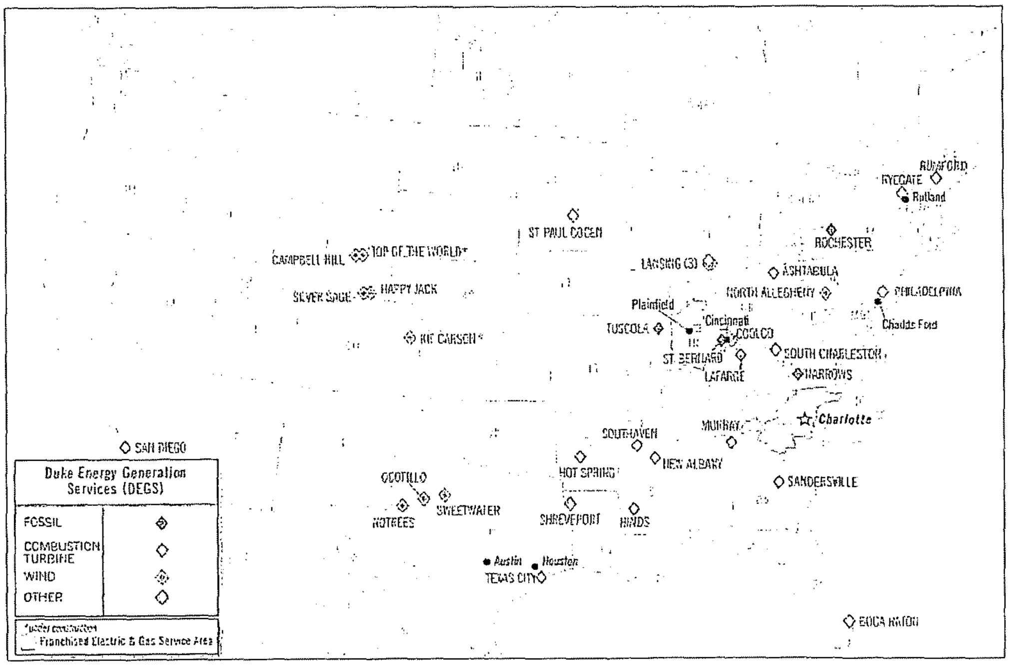
Commercial Power Midwest Power Generation Facilities



Through DEGS, Commercial Power is an on-site energy solutions and utility services provider. Primarily through joint ventures, DEGS engages in utility systems construction, operation and maintenance of utility facilities, as well as cogeneration. Cogeneration is the simultaneous production of two or more forms of usable energy from a single source. DEGS currently has approximately 735 net MW of wind energy in operation and over 5,000 MW of wind energy projects in the development pipeline. DEGS also is developing transmission, solar and biomass projects.

The following map shows the location of DEGS generation assets.

Duke Energy Generation Services — North America
Power Generation Facilities and Offices



Rates and Regulation

Effective January 1, 2009, approximately half of Commercial Power's generation assets operate under an ESP, which expires on December 31, 2011. Prior to the ESP, these generation assets had been contracted through the RSP, which expired on December 31, 2008. The ESP consists of the following discrete charges:

- Annually Adjusted Component (AAC) Rider — This rider is intended to provide cost recovery primarily for certain environmental compliance expenditures. This component is avoidable (or by-passable) by all customers that switch to an alternative electric service provider.
- Fuel and Purchased Power (FPP) Rider — This rider is intended to provide cost recovery for fuel, purchased power and emission allowance expenses (including carbon or energy taxes) incurred to generate or procure electricity for retail ratepayers that are provided service by Duke Energy Ohio. This component is avoidable (or by-passable) by all customers that switch to an alternative electric service provider.
- Capacity Dedication Rider — This rider is intended to provide cost recovery for maintaining the generation fleet to serve the retail rate payers. This component is not avoidable (or non-by-passable) by customers that switch to an alternative electric service provider.
- System Reliability Tracker — This tracker is intended to provide actual cost recovery for capacity purchases made to maintain adequate reserve margin. This component is not avoidable (or non-by-passable) by all customers that switch to an alternative electric service provider.
- Base Generation Charge — This component reflects a market price for retail generation service and is not a cost-based rate. This component is avoidable (or by-passable) by all customers that switch to an alternative electric service provider.
- Transmission Cost Recovery Rider — The generation portion of this rider is designed to permit Duke Energy Ohio to recover certain Midwest ISO charges and all FERC approved transmission costs allocable to retail ratepayers that are provided service by Duke Energy Ohio. This component is avoidable (or by-passable) by all customers that switch to an alternative electric service provider.

Commercial Power's generation operations in the Midwest include generation assets located in Ohio that are dedicated to serve Ohio native load customers. These assets, as excess capacity allows, also generate revenues through sales outside the native load customer base, and such revenue is termed non-native.

Prior to December 17, 2008, Commercial Power did not apply regulatory accounting treatment to any of its operations due to the comprehensive electric deregulation legislation passed by the state of Ohio in 1999. In April 2008, new legislation (SB 221) was passed in Ohio and signed by the Governor of Ohio on May 1, 2008. The new law codified the PUCO's authority to approve an electric utility's standard service offer either through an ESP or a MRO, which is a price determined through a competitive bidding process. On July 31, 2008, Duke Energy Ohio filed an ESP and, with certain amendments, the ESP was approved by the PUCO on December 17, 2008. The approval of the ESP on December 17, 2008 resulted in the reapplication of regulatory accounting treatment to certain portions of Commercial Power's operations as of that date. The ESP became effective on January 1, 2009.

Under the ESP, Commercial Power bills for its native load generation via numerous riders. SB 221 and the ESP resulted in the approval of an enhanced recovery mechanism for certain of these riders, which includes, but is not limited to, a price-to-compare fuel and purchased power rider and certain portions of a price-to-compare cost of environmental compliance rider. Accordingly, Commercial Power began applying regulatory accounting treatment to the corresponding RSP riders that enhanced the recovery mechanism for recovery under the ESP on December 17, 2008. The remaining portions of Commercial Power's Ohio native load generation operations, revenues from which are reflected in rate riders for which the ESP does not specifically allow enhanced recovery, as well as all generation operations associated with non-native customers, including Commercial Power's Midwest gas-fired generation assets, continue to not apply regulatory accounting as those operations do not meet the necessary accounting criteria. Moreover, generation remains a competitive market in Ohio and native load customers continue to have the ability to switch to alternative suppliers for their electric generation service. As customers switch, there is a risk that some or all of the regulatory assets will not be recovered through the established riders. In assessing the probability of recovery of its regulatory assets established for its native load generation operations, Duke Energy continues to monitor the amount of native load customers that have switched to alternative suppliers. At December 31, 2009, management has concluded that the established regulatory assets are still probable of recovery even though there have been increased levels of customer switching.

Despite certain portions of the Ohio native load operations not meeting the criteria for applying regulatory accounting treatment, all of Commercial Power's Ohio native load operations' rates are subject to approval by the PUCO, and thus these operations are referred to here-in as Commercial Power's regulated operations.

Commercial Power is subject to regulation at the state level, primarily from PUCO and at the federal level, primarily from FERC. The PUCO approves prices for all retail electric generation sales by Duke Energy Ohio for its native retail service territory. See "Regulation" section within U.S. Franchised Electric and Gas for additional information regarding deregulation in Ohio.

Regulations of FERC and the PUCO govern access to regulated electric customer and other data by non-regulated entities, and services provided between regulated and non-regulated energy affiliates. These regulations affect the activities of Commercial Power.

Other ongoing regulatory initiatives at both state and federal levels addressing market design, such as the development of capacity markets and real-time electricity markets, impact financial results from Commercial Power's marketing and generation activities.

Commercial Power is subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

See "Other Issues" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion about potential Global Climate Change legislation and the potential impacts such legislation could have on Duke Energy's operations.

Market Environment and Competition

Similar to U.S. Franchised Electric and Gas' operations, the overall economic conditions have negatively impacted Commercial Power's retail volumes for all customer classes. Commercial Power competes for wholesale contracts for the purchase and sale of electricity, coal, natural gas and emission allowances. The market price of commodities and services, along with the quality and reliability of services provided, drive competition in the energy marketing business. Commercial Power's main competitors include other non-regulated generators in the Midwestern U.S. wholesale power, coal and natural gas marketers, renewable energy companies and financial institutions and hedge funds engaged in energy commodity marketing and trading.

Low commodity prices in 2009 have put downward pressure on power prices. The available capacity and lower prices have provided opportunities for customers in Ohio to switch generation suppliers. Competitive power suppliers have begun supplying power to current Commercial Power customers in Ohio and Commercial Power experienced an increase in customer switching beginning in the second quarter of 2009 and accelerating in the later part of the year. As of December 31, 2009, customer switching levels approximated 40% of Commercial Power's Ohio native load. However, through DERS, Commercial Power was able to acquire approximately 60% of the switched load by offering customers a discount to the ESP price. Additionally, DERS has been able to acquire new customers previously served by other Ohio franchised utilities.

Fuel Supply

Commercial Power relies on coal and natural gas for its generation of electric energy.

Coal.

Commercial Power meets its coal demand through a portfolio of purchase supply contracts and spot agreements. Large amounts of coal are purchased under supply contracts with mining operators who mine both underground and at the surface. Commercial Power uses spot-market purchases to meet coal requirements not met by supply contracts. Expiration dates for its supply contracts, which have various price adjustment provisions and market re-openers, range from 2010 to 2012. Commercial Power expects to renew these contracts or enter into similar contracts with other suppliers for the quantities and quality of coal required as existing contracts expire, though prices will fluctuate over time as coal markets change. The coal purchased is primarily produced in Illinois, Ohio and eastern Kentucky. Commercial Power has an adequate supply of coal to fuel its projected 2010 operations and a significant portion of supply to fuel its projected 2011 operations. The majority of Commercial Power's coal-fired generation is equipped with flue gas desulfurization equipment. As a result, Commercial Power is able to satisfy the current emission limitations for SO_2 for existing facilities.

Gas.

Commercial Power is responsible for the purchase and the subsequent delivery of natural gas to its gas turbine generators. The majority of Commercial Power's natural gas requirements are purchased in the spot market on an as-needed basis.

INTERNATIONAL ENERGY

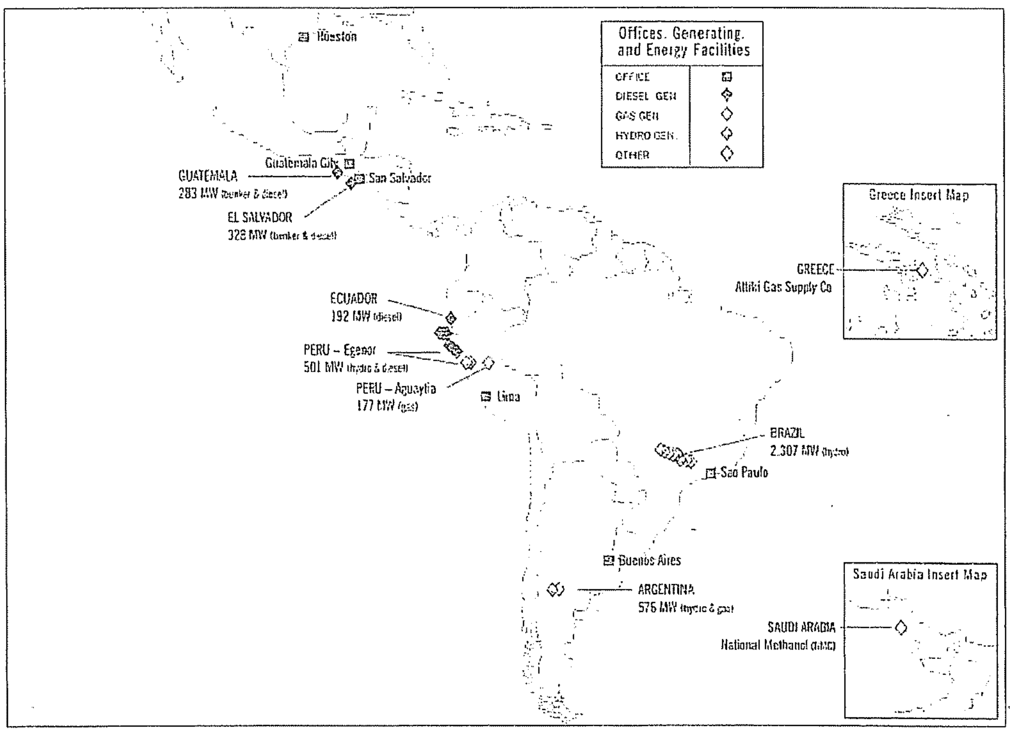
International Energy principally operates and manages power generation facilities and engages in sales and marketing of electric power and natural gas outside the U.S. It conducts operations primarily through DEI and its affiliates and its activities target power generation in Latin America. Additionally, International Energy has equity method investments in NMC, located in Saudi Arabia, which is a regional producer of MTBE and Attiki, located in Athens, Greece, which is a natural gas distributor and was acquired in connection with the Cinergy merger. In December 2009, International Energy decided to abandon its investment in Attiki. See Note 12 to the Consolidated Financial Statements, "Investments in Unconsolidated Affiliates and Related Party Transactions," for additional information.

International Energy's customers include retail distributors, electric utilities, independent power producers, marketers and industrial/commercial companies. International Energy's current strategy is focused on optimizing the value of its current Latin American portfolio and expanding the portfolio through investment in generation opportunities in Latin America.

International Energy owns, operates or has substantial interests in approximately 4,000 net MW of generation facilities.

The following map shows the locations of International Energy's facilities, including its interests in non-electric generation facilities in Saudi Arabia and Greece.

Duke Energy International Facilities



Competition and Regulation

International Energy's sales and marketing of electric power and natural gas competes directly with other generators and marketers serving its market areas. Competitors are country and region-specific but include government-owned electric generating companies, local distribution companies with self-generation capability and other privately-owned electric generating and marketing companies. The principal elements of competition are price and availability, terms of service, flexibility and reliability of service.

A high percentage of International Energy's portfolio consists of base load hydroelectric generation facilities which compete with other forms of electric generation available to International Energy's customers and end-users, including natural gas and fuel oils. Economic activity, conservation, legislation, governmental regulations, weather, additional generation capacities and other factors affect the supply and demand for electricity in the regions served by International Energy.

International Energy's operations are subject to both country-specific and international laws and regulations. (See "Environmental Matters" in this section.)

OTHER

The remainder of Duke Energy's operations is presented as Other. While it is not considered a business segment, Other primarily includes certain unallocated corporate costs, Bison, Duke Energy's wholly-owned, captive insurance subsidiary, Duke Energy's effective 50% interest in Crescent and DukeNet and related telecom businesses. Additionally, Other includes the remaining portion of Duke Energy's business formerly known as DENA that was not exited or transferred to Commercial Power, primarily DETM, which is 60% owned by Duke Energy and 40% owned by Exxon Mobil Corporation and management is currently in the process of winding down. See Note 2 to the Consolidated Financial Statements, "Business Segments," for more information on Crescent.

Bison's principal activities as a captive insurance entity include the insurance and reinsurance of various business risks and losses, such as property, business interruption and general liability of subsidiaries and affiliates of Duke Energy.

Competition and Regulation

The entities within Other are subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

ENVIRONMENTAL MATTERS

Duke Energy is subject to international, federal, state and local laws and regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental matters. Environmental laws and regulations affecting Duke Energy include, but are not limited to:

- The Clean Air Act (CAA), as well as state laws and regulations impacting air emissions, including State Implementation Plans related to existing and new national ambient air quality standards for ozone and particulate matter. Owners and/or operators of air emission sources are responsible for obtaining permits and for annual compliance and reporting.
- The Clean Water Act which requires permits for facilities that discharge wastewaters into the environment.
- The Comprehensive Environmental Response, Compensation and Liability Act, which can require any individual or entity that currently owns or in the past may have owned or operated a disposal site, as well as transporters or generators of hazardous substances sent to a disposal site, to share in remediation costs.
- The Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, which requires certain solid wastes, including hazardous wastes, to be managed pursuant to a comprehensive regulatory regime.
- The National Environmental Policy Act, which requires federal agencies to consider potential environmental impacts in their decisions, including siting approvals.
- The North Carolina clean air legislation that froze electric utility rates from June 20, 2002 to December 31, 2007 (rate freeze period), subject to certain conditions, in order for North Carolina electric utilities, including Duke Energy, to significantly reduce emissions of SO_2 and nitrogen oxide (NO_x) from coal-fired power plants in the state. The legislation allows electric utilities, including Duke Energy, to accelerate the recovery of compliance costs by amortizing them over seven years (2003-2009). However, Duke Energy Carolinas ended its amortization in 2007 as part of its rate case settlement with the NCUC.

See "Other Issues" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion about potential Global Climate Change legislation and the potential impacts such legislation could have on Duke Energy's operations. Additionally, other potential future environmental laws and regulations could have a significant impact on Duke Energy's results of operations, cash flows or financial position. However, if such laws are enacted, Duke Energy would seek appropriate regulatory recovery of costs to comply within its regulated operations.

For more information on environmental matters involving Duke Energy, including possible liability and capital costs, see Notes 4 and 16 to the Consolidated Financial Statements, "Regulatory Matters," and "Commitments and Contingencies — Environmental," respectively.

Except to the extent discussed in Note 4 to the Consolidated Financial Statements, "Regulatory Matters," and Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies," compliance with current international, federal, state and local provisions regulating the discharge of materials into the environment, or otherwise protecting the environment, is incorporated into the routine cost structure of our various business segments and is not expected to have a material adverse effect on the competitive position, consolidated results of operations, cash flows or financial position of Duke Energy.

GEOGRAPHIC REGIONS

For a discussion of Duke Energy's foreign operations and certain of the risks associated with them, see "Risk Factors," "Management's Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk — Foreign Currency Risk," and Notes 2 and 8 to the Consolidated Financial Statements, "Business Segments" and "Risk Management, Derivative Instruments and Hedging Activities," respectively.

EMPLOYEES

On December 31, 2009, Duke Energy had approximately 18,680 employees. A total of approximately 4,620 operating and maintenance employees were represented by unions.

EXECUTIVE OFFICERS OF DUKE ENERGY

Stephen G. De May	47	*Senior Vice President, Investor Relations and Treasurer.* Mr. De May assumed the role of Treasurer in November 2007 and in October 2009 Mr. De May assumed additional responsibility for investor relations. Prior to that, he served as Assistant Treasurer since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. De May served as Vice President, Energy and Environmental Policy of Duke Energy since February 2004.
Lynn J. Good	50	*Group Executive and Chief Financial Officer.* Ms. Good assumed her current position in July 2009. In November 2007, Ms. Good began serving as President, Commercial Businesses. Prior to that, she served as Senior Vice President and Treasurer since December 2006; prior to that she served as Treasurer and Vice President, Financial Planning since October 2006; and prior to that she served as Vice President and Treasurer since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Ms. Good served as Executive Vice President and Chief Financial Officer of Cinergy from August 2005 and Vice President, Finance and Controller of Cinergy from November 2003 to August 2005.
Dhiaa M. Jamil	53	*Group Executive, Chief Generation Officer and Chief Nuclear Officer.* Mr. Jamil assumed his position as Chief Generation Officer in July 2009 and his position as Chief Nuclear Officer in February 2008. Prior to that he served as Senior Vice President, Nuclear Support, Duke Energy Carolinas, LLC since March 2007.
Marc E. Manly	57	*Group Executive, Chief Legal Officer and Corporate Secretary.* Mr. Manly assumed the role of Corporate Secretary in December 2008 and assumed position of Chief Legal Officer in April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. Manly served as Executive Vice President and Chief Legal Officer of Cinergy since November 2002.
James E. Rogers	62	*Chairman, President and Chief Executive Officer.* Mr. Rogers assumed the role of Chief Executive Officer and President in April 2006, upon the merger of Duke Energy and Cinergy and assumed the role of Chairman on January 2, 2007. Until the merger of Duke Energy and Cinergy, Mr. Rogers served as Chairman of the Board of Cinergy since 2000 and as Chief Executive Officer of Cinergy since 1995.
B. Keith Trent	50	*Group Executive, President, Commercial Businesses.* Mr. Trent assumed his current position in July 2009. Prior to that he served as Group Executive and Chief Strategy, Policy and Regulatory Officer since May 2007. Prior to that he served as Group Executive and Chief Strategy and Policy Officer since October 2006 and prior to that he served as Group Executive and Chief Development Officer since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. Trent served as Executive Vice President, General Counsel and Secretary of Duke Energy since March 2005. Prior to that he served as General Counsel, Litigation of Duke Energy from May 2002 to March 2005.
James L. Turner	50	*Group Executive; President and Chief Operating Officer, U.S. Franchised Electric and Gas.* Mr. Turner assumed his current position in May 2007. Prior to that he served as Group Executive and President, U.S. Franchised Electric and Gas since October 2006, and prior to that he served as Group Executive and Chief Commercial Officer, U.S. Franchised Electric and Gas since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. Turner served as President of Cinergy since 2005, Executive Vice President and Chief Financial Officer of Cinergy from 2004 to 2005.
Steven K. Young	51	*Senior Vice President and Controller.* Mr. Young assumed his current position in December 2006. Prior to that he served as Vice President and Controller since April 2006, upon the merger of Duke Energy and Cinergy. Until the merger of Duke Energy and Cinergy, Mr. Young served as Vice President and Controller of Duke Energy since June 2005. Prior to that Mr. Young served as Senior Vice President and Chief Financial Officer of Duke Energy Carolinas from March 2003 to June 2005.

Executive officers serve until their successors are duly elected.

There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection.

ITEM 1A. RISK FACTORS.

Duke Energy's franchised electric revenues, earnings and results are dependent on state legislation and regulation that affect electric generation, transmission, distribution and related activities, which may limit Duke Energy's ability to recover costs.

Duke Energy's franchised electric businesses are regulated on a cost-of-service/rate-of-return basis subject to the statutes and regulatory commission rules and procedures of North Carolina, South Carolina, Ohio, Indiana and Kentucky. If Duke Energy's franchised electric earnings exceed the returns established by the state regulatory commissions, Duke Energy's retail electric rates may be subject to review and possible reduction by the commissions, which may decrease Duke Energy's future earnings. Additionally, if regulatory bodies do not allow recovery of costs incurred in providing service on a timely basis, Duke Energy's future earnings could be negatively impacted.

Duke Energy may incur substantial costs and liabilities due to Duke Energy's ownership and operation of nuclear generating facilities.

Duke Energy's ownership interest in and operation of three nuclear stations subject Duke Energy to various risks including, among other things: the potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials; limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

Duke Energy's ownership and operation of nuclear generation facilities requires Duke Energy to meet licensing and safety-related requirements imposed by the NRC. In the event of non-compliance, the NRC may increase regulatory oversight, impose fines, and/or shut down a unit, depending upon its assessment of the severity of the situation. Revised security and safety requirements promulgated by the NRC, which could be prompted by, among other things, events within or outside of Duke Energy's control, such as a serious nuclear incident at a facility owned by a third-party, could necessitate substantial capital and other expenditures at Duke Energy's nuclear plants, as well as assessments against Duke Energy to cover third-party losses. In addition, if a serious nuclear incident were to occur, it could have a material adverse effect on Duke Energy's results of operations and financial condition.

Duke Energy's ownership and operation of nuclear generation facilities also requires Duke Energy to maintain funded trusts that are intended to pay for the decommissioning costs of Duke Energy's nuclear power plants. Poor investment performance of these decommissioning trusts' holdings and other factors impacting decommissioning costs could unfavorably impact Duke Energy's liquidity and results of operations as Duke Energy could be required to significantly increase its cash contributions to the decommissioning trusts.

Duke Energy's plans for future expansion and modernization of its generation fleet subject it to risk of failure to adequately execute and manage its significant construction plans, as well as the risk of recovering all such costs or of recovering costs in an untimely manner, which could materially impact Duke Energy's results of operations, cash flows or financial position.

During the three year period from 2010 to 2012, Duke Energy anticipates cumulative capital expenditures of approximately $14 billion to $15 billion of which approximately $11 billion relates to its regulated U.S. Franchised Electric and Gas businesses. The completion of Duke Energy's anticipated capital investment projects in existing and new generation facilities is subject to many construction and development risks, including, but not limited to, risks related to financing, obtaining and complying with terms of permits, meeting construction budgets and schedules, and satisfying operating and environmental performance standards. Moreover, Duke Energy's ability to recover all these costs and recovering costs in a timely manner could materially impact Duke Energy's consolidated financial position, results of operations or cash flows.

Duke Energy's sales may decrease if Duke Energy is unable to gain adequate, reliable and affordable access to transmission assets.

Duke Energy depends on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity Duke Energy sells to the wholesale market. FERC's power transmission regulations, as well as those of Duke Energy's international markets, require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. If transmission is disrupted, or if transmission capacity is inadequate, Duke Energy's ability to sell and deliver products may be hindered.

The different regional power markets have changing regulatory structures, which could affect Duke Energy's growth and performance in these regions. In addition, the independent system operators who oversee the transmission systems in regional power markets have imposed in the past, and may impose in the future, price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of Duke Energy's wholesale power marketing business.

Duke Energy may be unable to secure long-term power sales agreements or transmission agreements, which could expose Duke Energy's sales to increased volatility.

In the future, Duke Energy may not be able to secure long-term power sales agreements to customers for Duke Energy's unregulated power generation facilities. If Duke Energy is unable to secure these types of agreements, Duke Energy's sales volumes would be exposed to increased volatility. Without the benefit of long-term customer power purchase agreements, Duke Energy cannot assure that it will be able to sell the power generated by Duke Energy's facilities or that Duke Energy's facilities will be able to operate profitably. The inability to secure these agreements could materially adversely affect Duke Energy's financial and operational results.

Competition in the unregulated markets in which Duke Energy operates may adversely affect the growth and profitability of Duke Energy's business.

Duke Energy may not be able to respond in a timely or effective manner to the many changes designed to increase competition in the electricity industry. To the extent competitive pressures increase, the economics of Duke Energy's business may come under long-term pressure.

In addition, regulatory changes have been proposed to increase access to electricity transmission grids by utility and non-utility purchasers and sellers of electricity. These changes could continue the disaggregation of many vertically-integrated utilities into separate generation, transmission, distribution and retail businesses. As a result, a significant number of additional competitors could become active in the wholesale power generation segment of Duke Energy's industry.

Duke Energy may also face competition from new competitors that have greater financial resources than Duke Energy does, seeking attractive opportunities to acquire or develop energy assets or energy trading operations both in the United States and abroad. These new competitors may include sophisticated financial institutions, some of which are already entering the energy trading and marketing sector, and international energy players, which may enter regulated or unregulated energy businesses. This competition may adversely affect Duke Energy's ability to make investments or acquisitions.

Customers of Duke Energy Ohio have recently begun to select alternative electric generation service providers, as allowed by Ohio legislation.

Under current Ohio legislation, electric generation is sold in a competitive market in Ohio, and Duke Energy's native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. Competitive power suppliers have announced intentions of supplying power to Duke Energy's current customers in Ohio, and Duke Energy has experienced an increase in customer switching in the second half of 2009. These evolving market conditions may continue to impact Duke Energy's results of operations, and also may impact Duke Energy's ability to continue to apply regulatory accounting treatment to certain portions of its Commercial Power business segment.

Duke Energy must meet credit quality standards and there is no assurance that it and its rated subsidiaries will maintain investment grade credit ratings. If Duke Energy or its rated subsidiaries are unable to maintain an investment grade credit rating, Duke Energy would be required under credit agreements to provide collateral in the form of letters of credit or cash, which may materially adversely affect Duke Energy's liquidity.

Each of Duke Energy's and its rated subsidiaries senior unsecured long-term debt is currently rated investment grade by various rating agencies. Duke Energy cannot be sure that the senior unsecured long-term debt of Duke Energy or its rated subsidiaries will be rated investment grade in the future.

If the rating agencies were to rate Duke Energy or its rated subsidiaries below investment grade, the entity's borrowing costs would increase, perhaps significantly. In addition, Duke Energy or its rated subsidiaries would likely be required to pay a higher interest rate in future financings, and its potential pool of investors and funding sources would likely decrease. Further, if its short-term debt rating were to fall, the entity's access to the commercial paper market could be significantly limited. Any downgrade or other event negatively affecting the credit ratings of Duke Energy's subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase Duke Energy's need to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing the liquidity and borrowing availability of the consolidated group.

A downgrade below investment grade could also require Duke Energy to post additional collateral in the form of letters of credit or cash under various credit agreements and trigger termination clauses in some interest rate derivative agreements, which would require cash payments. All of these events would likely reduce Duke Energy's liquidity and profitability and could have a material adverse effect on Duke Energy's financial position, results of operations or cash flows.

Duke Energy relies on access to short-term money markets and longer-term capital markets to finance Duke Energy's capital requirements and support Duke Energy's liquidity needs, and Duke Energy's access to those markets can be adversely affected by a number of conditions, many of which are beyond Duke Energy's control.

Duke Energy's business is financed to a large degree through debt and the maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from Duke Energy's assets. Accordingly, Duke Energy relies on access to both short-term money markets and longer-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from Duke Energy's operations and to fund investments originally financed through debt instruments with disparate maturities. If Duke Energy is not able to access capital at competitive rates or at all, Duke Energy's ability to finance its operations and implement its strategy and business plan as scheduled could be adversely affected. An inability to access capital may limit Duke Energy's ability to pursue improvements or acquisitions that Duke Energy may otherwise rely on for future growth.

Market disruptions may increase Duke Energy's cost of borrowing or adversely affect Duke Energy's ability to access one or more financial markets. Such disruptions could include: economic downturns; the bankruptcy of an unrelated energy company; capital market conditions generally; market prices for electricity and gas; terrorist attacks or threatened attacks on Duke Energy's facilities or unrelated energy companies; or the overall health of the energy industry.

Duke Energy maintains revolving credit facilities to provide back-up for commercial paper programs and/or letters of credit at various entities. These facilities typically include financial covenants which limit the amount of debt that can be outstanding as a percentage of the total capital for the specific entity. Failure to maintain these covenants at a particular entity could preclude Duke Energy from issuing commercial paper or Duke Energy and its affiliates from issuing letters of credit or borrowing under the revolving credit facility. Additionally, failure to comply with these financial covenants could result in Duke Energy being required to immediately pay down any outstanding amounts under other revolving credit agreements.

Duke Energy's investments and projects located outside of the United States expose Duke Energy to risks related to laws of other countries, taxes, economic conditions, political conditions and policies of foreign governments. These risks may delay or reduce Duke Energy's realization of value from Duke Energy's international projects.

Duke Energy currently owns and may acquire and/or dispose of material energy-related investments and projects outside the United States. The economic, regulatory, market and political conditions in some of the countries where Duke Energy has interests or in which Duke Energy may explore development, acquisition or investment opportunities could present risks related to, among others, Duke Energy's ability to obtain financing on suitable terms, Duke Energy's customers' ability to honor their obligations with respect to projects and investments, delays in construction, limitations on Duke Energy's ability to enforce legal rights, and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law, regulations, market rules or tax policy.

Duke Energy's investments and projects located outside of the United States expose Duke Energy to risks related to fluctuations in currency rates. These risks, and Duke Energy's activities to mitigate such risks, may adversely affect Duke Energy's cash flows and results of operations.

Duke Energy's operations and investments outside the United States expose Duke Energy to risks related to fluctuations in currency rates. As each local currency's value changes relative to the U.S. dollar — Duke Energy's principal reporting currency — the value in U.S. dollars of Duke Energy's assets and liabilities in such locality and the cash flows generated in such locality, expressed in U.S. dollars, also change. Duke Energy's primary foreign currency rate exposure is to the Brazilian Real.

Duke Energy selectively mitigates some risks associated with foreign currency fluctuations by, among other things, indexing contracts to the U.S. dollar and/or local inflation rates, hedging through debt denominated or issued in the foreign currency and hedging through foreign currency derivatives. These efforts, however, may not be effective and, in some cases, may expose Duke Energy to other risks that could negatively affect Duke Energy's cash flows and results of operations.

Duke Energy is exposed to credit risk of the customers and counterparties with whom Duke Energy does business.

Adverse economic conditions affecting, or financial difficulties of, customers and counterparties with whom Duke Energy does business could impair the ability of these customers and counterparties to pay for Duke Energy's services or fulfill their contractual obligations, including loss recovery payments under insurance contracts, or cause them to delay such payments or obligations. Duke Energy depends on these customers and counterparties to remit payments on a timely basis. Any delay or default in payment could adversely affect Duke Energy's cash flows, financial position or results of operations.

Poor investment performance of pension plan holdings and other factors impacting pension plan costs could unfavorably impact Duke Energy's liquidity and results of operations.

Duke Energy's costs of providing non-contributory defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and Duke Energy's required or voluntary contributions made to the plans. While Duke Energy complied with the minimum funding requirements as of December 31, 2009, Duke Energy has certain qualified U.S. pension plans with obligations which exceeded the value of plan assets by approximately $471 million. Without sustained growth in the pension investments over time to increase the value of Duke Energy's plan assets and depending upon the other factors impacting Duke Energy's costs as listed above, Duke Energy could be required to fund its plans with significant amounts of cash. Such cash funding obligations could have a material impact on Duke Energy's financial position, results of operations or cash flows.

Duke Energy is subject to numerous environmental laws and regulations that require significant capital expenditures, can increase Duke Energy's cost of operations, and which may impact or limit Duke Energy's business plans, or expose Duke Energy to environmental liabilities.

Duke Energy is subject to numerous environmental laws and regulations affecting many aspects of Duke Energy's present and future operations, including air emissions (such as reducing NO_x, SO_2 and mercury emissions in the U.S., or potential future control of greenhouse-gas emissions), water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating, and other costs. These laws and regulations generally require Duke Energy to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising out of contaminated properties, and failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets. The steps Duke Energy could be required to take to ensure that its facilities are in compliance could be prohibitively expensive. As a result, Duke Energy may be required to shut down or alter the operation of its facilities, which may cause Duke Energy to incur losses. Further, Duke Energy's regulatory rate structure and Duke Energy's contracts with customers may not necessarily allow Duke Energy to recover capital costs Duke Energy incurs to comply with new environmental regulations. Also, Duke Energy may not be able to obtain or maintain from time to time all required environmental regulatory approvals for Duke Energy's operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals, if Duke Energy fails to obtain and comply with them or if environmental laws or regulations change and become more stringent, then the operation of Duke Energy's facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. Although it is not expected that the costs of complying with current environmental regulations will have a material adverse effect on Duke Energy's financial position, results of operations or cash flows, no assurance can be made that the costs of complying with environmental regulations in the future will not have such an effect.

There is growing consensus that some form of regulation will be forthcoming at the federal level with respect to greenhouse gas emissions (including CO_2) and such regulation could result in the creation of substantial additional costs in the form of taxes or emission allowances.

The EPA also has plans to propose new federal regulations governing the management of coal combustion by-products, including fly ash. These regulations may require Duke Energy to make additional capital expenditures and increase Duke Energy's operating and maintenance costs.

Additionally, potential other new environmental regulations, including the use of coal from mountain removal and water discharge, could require Duke Energy to make additional capital expenditures and increase costs of fuel.

In addition, Duke Energy is generally responsible for on-site liabilities, and in some cases off-site liabilities, associated with the environmental condition of Duke Energy's power generation facilities and natural gas assets which Duke Energy has acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with some acquisitions and sales of assets, Duke Energy may obtain, or be required to provide, indemnification against some environmental liabilities. If Duke Energy incurs a material liability, or the other party to a transaction fails to meet its indemnification obligations to Duke Energy, Duke Energy could suffer material losses.

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect Duke Energy's financial position, results of operations or cash flows and Duke Energy's utilities' businesses.

Increased competition resulting from deregulation or restructuring efforts, including from the Energy Policy Act of 2005, could have a significant adverse financial impact on Duke Energy and Duke Energy's utility subsidiaries and consequently on Duke Energy's results of operations, financial position, or cash flows. Increased competition could also result in increased pressure to lower costs, including the cost of electricity. Retail competition and the unbundling of regulated energy and gas service could have a significant adverse financial impact on Duke Energy and Duke Energy's subsidiaries due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Duke Energy cannot predict the extent and timing of entry by additional competitors into the electric markets. Duke Energy cannot predict when Duke Energy will be subject to changes in legislation or regulation, nor can Duke Energy predict the impact of these changes on its financial position, results of operations or cash flows.

Duke Energy is involved in numerous legal proceedings, the outcome of which are uncertain, and resolution adverse to Duke Energy could negatively affect Duke Energy's financial position, results of operations or cash flows.

Duke Energy is subject to numerous legal proceedings, including claims for damages for bodily injuries alleged to have arisen prior to 1985 from the exposure to or use of asbestos at electric generation plants of Duke Energy Carolinas. Litigation is subject to many uncertainties and Duke Energy cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which Duke Energy is involved could require Duke Energy to make additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could have a material effect on Duke Energy's cash flows and results of operations. Similarly, it is reasonably possible that the terms of resolution could require Duke Energy to change Duke Energy's business practices and procedures, which could also have a material effect on Duke Energy's cash flows, financial position or results of operations.

Duke Energy's results of operations may be negatively affected by overall market, economic and other conditions that are beyond Duke Energy's control.

Sustained downturns or sluggishness in the economy generally affect the markets in which Duke Energy operates and negatively influence Duke Energy's energy operations. Declines in demand for energy as a result of economic downturns in Duke Energy's franchised electric service territories will reduce overall sales and lessen Duke Energy's cash flows, especially as Duke Energy's industrial customers reduce production and, therefore, consumption of electricity and gas. Although Duke Energy's franchised electric and gas business is subject to regulated allowable rates of return and recovery of certain costs, such as fuel under periodic adjustment clauses, overall declines in electricity sold as a result of economic downturn or recession could reduce revenues and cash flows, thus diminishing results of operations. Additionally, prolonged economic downturns that negatively impact Duke Energy's results of operations and cash flows could result in future material impairment charges being recorded to write-down the carrying value of certain assets, including goodwill, to their respective fair values.

Duke Energy also sells electricity into the spot market or other competitive power markets on a contractual basis. With respect to such transactions, Duke Energy is not guaranteed any rate of return on Duke Energy's capital investments through mandated rates, and Duke Energy's revenues and results of operations are likely to depend, in large part, upon prevailing market prices in Duke Energy's regional markets and other competitive markets. These market prices may fluctuate substantially over relatively short periods of time and could reduce Duke Energy's revenues and margins and thereby diminish Duke Energy's results of operations.

Factors that could impact sales volumes, generation of electricity and market prices at which Duke Energy is able to sell electricity are as follows:

- weather conditions, including abnormally mild winter or summer weather that cause lower energy usage for heating or cooling purposes, respectively, and periods of low rainfall that decrease Duke Energy's ability to operate its facilities in an economical manner;
- supply of and demand for energy commodities;
- illiquid markets including reductions in trading volumes which result in lower revenues and earnings;
- transmission or transportation constraints or inefficiencies which impact Duke Energy's non-regulated energy operations;
- availability of competitively priced alternative energy sources, which are preferred by some customers over electricity produced from coal, nuclear or gas plants, and of energy-efficient equipment which reduces energy demand;
- natural gas, crude oil and refined products production levels and prices;
- ability to procure satisfactory levels of inventory, such as coal and uranium;
- electric generation capacity surpluses which cause Duke Energy's non-regulated energy plants to generate and sell less electricity at lower prices and may cause some plants to become non-economical to operate; and
- capacity and transmission service into, or out of, Duke Energy's markets.

These factors have led to industry-wide downturns that have resulted in the slowing down or stopping of construction of new power plants and announcements by Duke Energy and other energy suppliers and gas pipeline companies of plans to sell non-strategic assets, subject to regulatory constraints, in order to boost liquidity or strengthen balance sheets. Proposed sales by other energy suppliers could increase the supply of the types of assets that Duke Energy is attempting to sell. In addition, recent FERC actions addressing power market concerns could negatively impact the marketability of Duke Energy's electric generation assets.

Duke Energy's operating results may fluctuate on a seasonal and quarterly basis.

Electric power generation is generally a seasonal business. In most parts of the United States and other markets in which Duke Energy operates, demand for power peaks during the warmer summer months, with market prices typically peaking at that time. In other areas, demand for power peaks during the winter. Further, extreme weather conditions such as heat waves or winter storms could cause these seasonal fluctuations to be more pronounced. As a result, in the future, the overall operating results of Duke Energy's businesses may fluctuate substantially on a seasonal and quarterly basis and thus make period comparison less relevant.

Duke Energy's business is subject to extensive federal regulation that will affect Duke Energy's operations and costs.

Duke Energy is subject to regulation by FERC, the NRC and various other federal agencies. Regulation affects almost every aspect of Duke Energy's businesses, including, among other things, Duke Energy's ability to: take fundamental business management actions; determine the terms and rates of Duke Energy's transmission and distribution businesses' services; make acquisitions; issue equity or debt securities; engage in transactions between Duke Energy's utilities and other subsidiaries and affiliates; and the ability of the operating subsidiaries to pay dividends to Duke Energy. Changes to these regulations are ongoing, and Duke Energy cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on Duke Energy's business. However, changes in regulation (including re-regulating previously deregulated markets) can cause delays in or affect business planning and transactions and can substantially increase Duke Energy's costs.

New laws or regulations could have a negative impact on Duke Energy's financial position, cash flows or results of operations.

Changes in laws and regulations affecting Duke Energy, including new accounting standards could change the way Duke Energy is required to record revenues, expenses, assets and liabilities. These types of regulations could have a negative impact on Duke Energy's financial position, cash flows or results of operations or access to capital.

Potential terrorist activities or military or other actions could adversely affect Duke Energy's business.

The continued threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in prices for natural gas and oil which may materially adversely affect Duke Energy in ways Duke Energy cannot predict at this time. In addition, future acts of terrorism and any possible reprisals as a consequence of action by the United States and its allies could be directed against companies operating in the United States or their international affiliates. Infrastructure and generation facilities such as Duke Energy's nuclear plants could be potential targets of terrorist activities. The potential for terrorism has subjected Duke Energy's operations to increased risks and could have a material adverse effect on Duke Energy's business. In particular, Duke Energy may experience increased capital and operating costs to implement increased security for its plants, including its nuclear power plants under the NRC's design basis threat requirements, such as additional physical plant security, additional security personnel or additional capability following a terrorist incident.

The insurance industry has also been disrupted by these potential events. As a result, the availability of insurance covering risks Duke Energy and Duke Energy's competitors typically insure against may decrease. In addition, the insurance Duke Energy is able to obtain may have higher deductibles, higher premiums, lower coverage limits and more restrictive policy terms.

Additional risks and uncertainties not currently known to Duke Energy or that Duke Energy currently deems to be immaterial also may materially adversely affect Duke Energy's financial condition, results of operations or cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

U.S. FRANCHISED ELECTRIC AND GAS

As of December 31, 2009, U.S. Franchised Electric and Gas operated three nuclear generating stations with a combined owned capacity of 5,173 MW (including an approximate 19% ownership in the Catawba Nuclear Station), fifteen coal-fired stations with an overall combined owned capacity of 13,189 MW, (including a 69% ownership in the East Bend Steam Station and an approximate 50% ownership in Unit 5 of the Gibson Steam Station), thirty-one hydroelectric stations (including two pumped-storage facilities) with a combined owned capacity of 3,263 MW, fifteen CT stations with an overall combined owned capacity of 5,047 MW and one CC station with an owned capacity of 285 MW. The stations are located in North Carolina, South Carolina, Indiana, Ohio and Kentucky. The MW displayed in the table below are based on summer capacity.

Name	Total MW Capacity	Owned MW Capacity	Fuel	Location	Ownership Interest (percentage)
Carolinas:					
Oconee	2,538	2,538	Nuclear	SC	100%
Catawba[a]	2,258	435	Nuclear	SC	19.25
Belews Creek	2,220	2,220	Coal	NC	100
McGuire	2,200	2,200	Nuclear	NC	100
Marshall	2,078	2,078	Coal	NC	100
Bad Creek	1,360	1,360	Hydro	SC	100
Lincoln CT	1,267	1,267	Natural gas/Fuel oil	NC	100
Allen	1,127	1,127	Coal	NC	100
Rockingham CT	825	825	Natural gas/Fuel oil	NC	100
Cliffside	760	760	Coal	NC	100
Jocassee	730	730	Hydro	SC	100
Mill Creek CT	595	595	Natural gas/Fuel oil	SC	100
Riverbend	454	454	Coal	NC	100
Lee	370	370	Coal	SC	100
Buck	369	369	Coal	NC	100
Cowans Ford	325	325	Hydro	NC	100
Dan River	276	276	Coal	NC	100
Buzzard Roost CT	196	196	Natural gas/Fuel oil	SC	100
Keowee	152	152	Hydro	SC	100
Lee CT	82	82	Natural gas/Fuel oil	SC	100
Riverbend CT	64	64	Natural gas/Fuel oil	NC	100
Buck CT	62	62	Natural gas/Fuel oil	NC	100
Dan River CT	48	48	Natural gas/Fuel oil	NC	100
Other small hydro (26 plants)	651	651	Hydro	NC/SC	100
Midwest:					
Gibson[b]	3,132	2,822	Coal	IN	90
Cayuga[c]	1,005	1,005	Coal/Fuel oil	IN	100
East Bend[d]	600	414	Coal	KY	69
Madison CT	576	576	Natural gas	OH	100
Gallagher	560	560	Coal	IN	100
Woodsdale CT	462	462	Natural gas/Propane	OH	100
Wheatland CT	460	460	Natural gas	IN	100
Wabash River[e]	411	411	Coal/Fuel oil	IN	100
Noblesville CC	285	285	Natural gas	IN	100
Miami Fort (Unit 6)	163	163	Coal	OH	100
Edwardsport	160	160	Coal/Fuel oil	IN	100
Henry County CT	129	129	Natural gas	IN	100
Cayuga CT	99	99	Natural gas/Fuel oil	IN	100
Miami Wabash CT	96	96	Fuel oil	IN	100
Connersville CT	86	86	Fuel oil	IN	100
Markland	45	45	Hydro	IN	100
Total	29,276	26,957			

(a) This generation facility is jointly owned by Duke Energy Carolinas, along with North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation and Piedmont Municipal Power Agency.
(b) Duke Energy Indiana owns and operates Gibson Station Units 1-4 and owns 50.05% of Unit 5, but is the operator. Unit 5 is jointly owned by Duke Energy Indiana, Wabash Valley Power Association, Inc. and Indiana Municipal Power Agency.
(c) Includes Cayuga Internal Combustion (IC).
(d) This generation facility is jointly owned by Duke Energy Kentucky and a subsidiary of Dayton Power and Light, Inc.
(e) Includes Wabash River IC.

In addition, as of December 31, 2009, U.S. Franchised Electric and Gas owned approximately 20,900 conductor miles of electric transmission lines, including 600 miles of 525 kilovolts (KV), 1,800 miles of 345 KV, 3,300 miles of 230 KV, 8,800 miles of 100 to 161 KV, and 6,400 miles of 13 to 69 KV. U.S. Franchised Electric and Gas also owned approximately 151,600 conductor miles of electric distribution lines, including 103,200 miles of overhead lines and 48,400 miles of underground lines, as of December 31, 2009 and approximately 7,200 miles of gas mains and approximately 6,000 miles of service lines. As of December 31, 2009, the electric transmission and distribution systems had approximately 2,300 substations. U.S. Franchised Electric and Gas also owns two underground caverns with a total storage capacity of approximately 16 million gallons of liquid propane. In addition, U.S. Franchised Electric and Gas has access to 5.5 million gallons of liquid propane storage and product loan through a commercial services agreement with a third party. This liquid propane is used in the three propane/air peak shaving plants located in Ohio and Kentucky. Propane/air peak shaving plants vaporize the propane and mix with natural gas to supplement the natural gas supply during peak demand periods and emergencies.

Substantially all of U.S. Franchised Electric and Gas' electric plant in service is mortgaged under the indenture relating to Duke Energy Carolinas', Duke Energy Ohio's and Duke Energy Indiana's various series of First Mortgage Bonds.

For a map showing U.S. Franchised Electric and Gas' properties, see "Business — U.S. Franchised Electric and Gas" earlier in this section.

COMMERCIAL POWER

The following table provides information about Commercial Power's generation portfolio as of December 31, 2009. The MW displayed in the table below are based on summer capacity.

Name	Total MW Capacity	Owned MW Capacity	Plant Type	Primary Fuel	Location	Approximate Ownership Interest (percentage)
Hanging Rock	1,240	1,240	Combined Cycle	Natural gas	OH	100%
Lee	640	640	Simple Cycle	Natural gas	IL	100
Vermillion[(a)]	640	480	Simple Cycle	Natural gas	IN	75
Fayette	620	620	Combined Cycle	Natural gas	PA	100
Washington	620	620	Combined Cycle	Natural gas	OH	100
Dick's Creek	152	152	Simple Cycle	Natural gas	OH	100
Beckjord CT	212	212	Simple Cycle	Fuel oil	OH	100
Miami Fort CT	60	60	Simple Cycle	Fuel oil	OH	100
Miami Fort (Units 7 and 8)[(b)]	1,000	640	Steam	Coal	OH	64
W.C. Beckjord[(b)]	1,124	862	Steam	Coal	OH	76.7
W.M. Zimmer[(b)]	1,300	605	Steam	Coal	OH	46.5
J.M. Stuart[(b)(c)]	2,340	912	Steam	Coal	OH	39
Killen[(b)(c)]	600	198	Steam	Coal	OH	33
Conesville[(b)(c)]	780	312	Steam	Coal	OH	40
Total Fossil & CT	11,328	7,553				
Happy Jack	29	29		Wind	WY	100
Ocotillo	59	59		Wind	TX	100
Notrees	153	153		Wind	TX	100
North Allegheny	70	70		Wind	PA	100
Campbell Hill	99	99		Wind	WY	100
Silver Sage	42	42		Wind	WY	100
Total Renewable Energy	452	452				
Total	11,780	8,005				

(a) This generation facility is jointly owned by Duke Energy Ohio and Wabash Valley Power Association, Inc.
(b) These generation facilities are jointly owned by Duke Energy Ohio and subsidiaries of American Electric Power, Inc. and/or Dayton Power and Light, Inc.
(c) Station is not operated by Duke Energy Ohio

In addition to the above facilities, Commercial Power owns an equity interest in the 585 MW capacity Sweetwater wind projects located in Texas. Commercial Power's share in these projects is 283 MW.

For a map showing Commercial Power's properties, see "Business — Commercial Power" earlier in this section.

INTERNATIONAL ENERGY

The following table provides information about International Energy's generation portfolio in continuing operations as of December 31, 2009.

Name	Total MW Capacity	Owned MW Capacity	Fuel	Location	Approximate Ownership Interest (percentage)
Paranapanema[(a)]	2,307	2,114	Hydro	Brazil	95%
Cerros Colorados	576	523	Hydro/Natural Gas	Argentina	91
Egenor	501	501	Hydro/Diesel	Peru	100
DEI Guatemala	283	283	Fuel Oil/Diesel	Guatemala	100
DEI El Salvador	328	296	Fuel Oil/Diesel	El Salvador	90
Electroquil	192	159	Diesel	Ecuador	83
Aguaytia	177	177	Natural Gas	Peru	100
Total	4,364	4,053			

(a) Includes Canoas I and II, which is jointly owned by Duke Energy and Companhia Brasileira de Aluminio.

International Energy also owns a 25% equity interest in NMC. In 2009, NMC produced approximately 1 million metric tons of methanol and 1 million metric tons of MTBE. Approximately 40% of methanol is normally used in the MTBE production. Additionally, International Energy owns a 25% equity interest in Attiki, which is a natural gas distributor within the geographical area of Athens, Greece. In December 2009, International Energy decided to abandon its investment in Attiki. See Note 12 to the Consolidated Financial Statements, "Investments in Unconsolidated Affiliates and Related Party Transactions," for additional information.

For additional information and a map showing International Energy's properties, see "Business — International Energy" earlier in this section.

OTHER

Duke Energy owns approximately 5.7 million square feet of corporate, regional and district office space spread throughout its service territories in the Carolinas and the Midwest. Additionally, Duke Energy leases approximately 1.5 million square feet of office space throughout the Carolinas, Midwest and in Houston, Texas. In February 2009, Duke Energy entered into a lease for approximately 500,000 square feet of office space in Charlotte, North Carolina that will become its new corporate headquarters.

ITEM 3. LEGAL PROCEEDINGS.

For information regarding legal proceedings, including regulatory and environmental matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters" and Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies — Litigation" and "Commitments and Contingencies — Environmental."

Brazilian Regulatory Citations.

On September 5, 2007, the State Environmental Agency of Parana assessed fines against International Energy of approximately $10 million for failure to comply with reforestation measures allegedly required by state regulations in Brazil. International Energy believes that federal law is controlling and has challenged the assessment. In addition, International Energy was assessed a fine by the federal environmental agency, IBAMA, in the amount of approximately $150 thousand for improper maintenance of existing reforested areas. International Energy believes that it has properly maintained all reforested areas and is also contesting this assessment. These assessed fines were judged to be valid in the administrative court between June and September 2009. International Energy has challenged these administrative court rulings by filing three judicial actions for annulment between July and October 2009.

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

No matters were submitted to a vote of Duke Energy's security holders during the fourth quarter of 2009.

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

Duke Energy's common stock is listed for trading on the New York Stock Exchange (NYSE) (ticker symbol DUK). As of February 22, 2010, there were approximately 160,575 common stockholders of record.

Common Stock Data by Quarter

	2009			2008		
		Stock Price Range(a)			Stock Price Range(a)	
	Dividends Per Share	High	Low	Dividends Per Share	High	Low
First Quarter	$0.23	$15.96	$11.72	$0.22	$20.60	$17.00
Second Quarter(b)	0.47	14.83	13.31	0.45	19.20	17.02
Third Quarter	—	16.02	14.10	—	19.10	16.77
Fourth Quarter(b)	0.24	17.94	15.33	0.23	17.99	13.50

(a) Stock prices represent the intra-day high and low stock price.
(b) Dividends paid in September 2009 and December 2009 increased from $0.23 per share to $0.24 per share and dividends paid in September 2008 and December 2008 increased from $0.22 per share to $0.23 per share.

Duke Energy expects to continue its policy of paying regular cash dividends; however, there is no assurance as to the amount of future dividends because they depend on future earnings, capital requirements, and financial condition, and are subject to declaration by the Board of Directors.

Duke Energy's operating subsidiaries have certain restrictions on their ability to transfer funds in the form of dividends or loans to Duke Energy. See "Liquidity and Capital Resources" within "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further information regarding these restrictions and their impacts on Duke Energy's liquidity.

Issuer Purchases of Equity Securities for Fourth Quarter of 2009

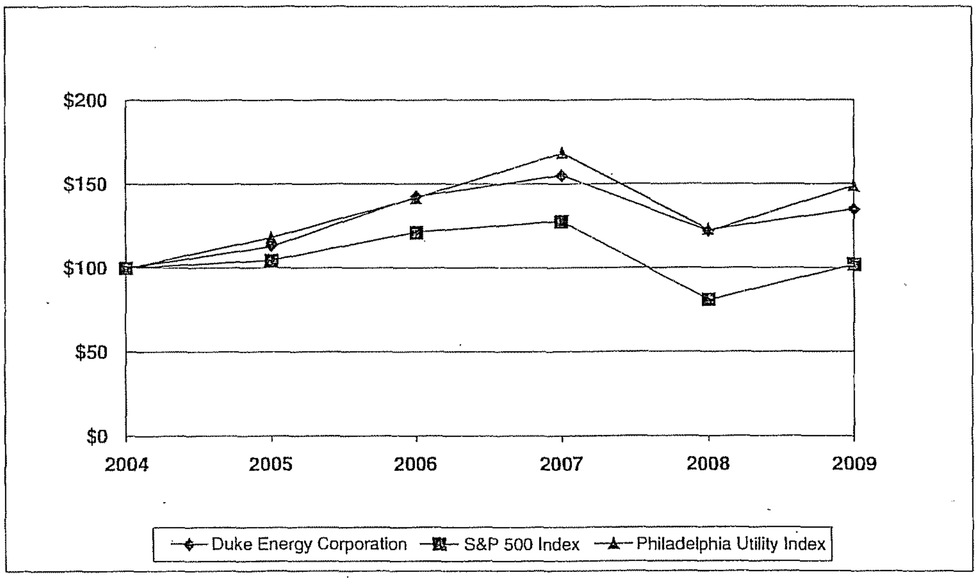
There were no repurchases of equity securities during the fourth quarter of 2009.

Stock Performance Graph

The performance graph below illustrates a five year comparison of cumulative total returns based on an initial investment of $100 in Duke Energy Corporation common stock, as compared with the Standard & Poor's (S&P) 500 Stock Index and the Philadelphia Utility Index for the five-year period 2005 through 2009.

This performance chart assumes $100 invested on December 31, 2004 in Duke Energy common stock, in the S&P 500 Stock Index and in the Philadelphia Utility Index and that all dividends are reinvested.

Comparison of Cumulative Five Year Total Return



NYSE CEO Certification

Duke Energy has filed the certification of its Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 as exhibits to this Annual Report on Form 10-K for the year ended December 31, 2009. In May 2009, Duke Energy's Chief Executive Officer, as required by Section 303A.12(a) of the NYSE Listed Company Manual, certified to the NYSE that he was not aware of any violation by Duke Energy of the NYSE's corporate governance listing standards.

ITEM 6. SELECTED FINANCIAL DATA.[(a)(b)]

(in millions, except per-share amounts)	2009	2008	2007	2006	2005
Statement of Operations					
Total operating revenues	$12,731	$13,207	$12,720	$10,607	$ 6,906
Total operating expenses	10,518	10,765	10,222	9,210	5,586
Gains on sales of investments in commercial and multi-family real estate	—	—	—	201	191
Gains (losses) on sales of other assets and other, net	36	69	(5)	223	(55)
Operating income	2,249	2,511	2,493	1,821	1,456
Total other income and expenses	333	121	428	354	217
Interest expense	751	741	685	632	381
Income from continuing operations before income taxes	1,831	1,891	2,236	1,543	1,292
Income tax expense from continuing operations	758	616	712	450	375
Income from continuing operations	1,073	1,275	1,524	1,093	917
Income (loss) from discontinued operations, net of tax	12	16	(22)	783	935
Income before cumulative effect of change in accounting principle and extraordinary items	1,085	1,291	1,502	1,876	1,852
Cumulative effect of change in accounting principle, net of tax and noncontrolling interest	—	—	—	—	(4)
Extraordinary items, net of tax	—	67	—	—	—
Net income	1,085	1,358	1,502	1,876	1,848
Dividends and premiums on redemption of preferred and preference stock	—	—	—	—	12
Net income (loss) attributable to noncontrolling interests	10	(4)	2	13	24
Net income attributable to Duke Energy Corporation	$ 1,075	$ 1,362	$ 1,500	$ 1,863	$ 1,812
Ratio of Earnings to Fixed Charges	3.0	3.4	3.7	2.6	2.4
Common Stock Data					
Shares of common stock outstanding[(c)]					
Year-end	1,309	1,272	1,262	1,257	928
Weighted average — basic	1,293	1,265	1,260	1,170	934
Weighted average — diluted	1,294	1,267	1,265	1,188	970
Income from continuing operations attributable to Duke Energy Corporation common shareholders					
Basic	$ 0.82	$ 1.01	$ 1.21	$ 0.92	$ 0.94
Diluted	0.82	1.01	1.20	0.91	0.92
Income (loss) from discontinued operations attributable to Duke Energy Corporation common shareholders					
Basic	$ 0.01	$ 0.02	$ (0.02)	$ 0.67	$ 1.00
Diluted	0.01	0.01	(0.02)	0.66	0.96
Earnings per share (before cumulative effect of change in accounting principle and extraordinary items)					
Basic	$ 0.83	$ 1.03	$ 1.19	$ 1.59	$ 1.94
Diluted	0.83	1.02	1.18	1.57	1.88
Earnings per share (from extraordinary items)					
Basic	$ —	$ 0.05	$ —	$ —	$ —
Diluted	—	0.05	—	—	—
Net income attributable to Duke Energy Corporation common shareholders					
Basic	$ 0.83	$ 1.08	$ 1.19	$ 1.59	$ 1.94
Diluted	0.83	1.07	1.18	1.57	1.88
Dividends per share[(d)]	0.94	0.90	0.86	1.26	1.17
Balance Sheet					
Total assets	$57,040	$53,077	$49,686	$68,700	$54,723
Long-term debt including capital leases, less current maturities	$16,113	$13,250	$ 9,498	$18,118	$14,547

(a) Significant transactions reflected in the results above include: 2009 impairment of goodwill and other assets (see Note 11 to the Consolidated Financial Statements, "Goodwill and Intangible Assets"), 2007 spin-off of the natural gas businesses (see Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies"), 2006 merger with Cinergy, 2006 Crescent joint venture transaction and subsequent deconsolidation effective September 7, 2006, 2005 DENA disposition, 2005 deconsolidation of DCP Midstream effective July 1, 2005, and 2005 Duke Energy Field Services, LLC (DEFS) sale of Texas Eastern Products Pipeline Company, LLC (TEPPCO).

(b) Periods prior to 2009 have been recast to reflect the adoption of the noncontrolling interest presentation provisions of Accounting Standards Codification 810 – Consolidation, which was adopted by Duke Energy effective January 1, 2009.

(c) 2006 increase primarily attributable to issuance of approximately 313 million shares in connection with Duke Energy's merger with Cinergy.

(d) 2007 decrease due to the spin-off of the natural gas businesses to shareholders on January 2, 2007 as dividends subsequent to the spin-off were split proportionately between Duke Energy and Spectra Energy such that the sum of the dividends of the two stand-alone companies approximated the former total dividend of Duke Energy prior to the spin-off.

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

INTRODUCTION

Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements and Notes for the years ended December 31, 2009, 2008 and 2007.

EXECUTIVE OVERVIEW

2009 Financial Results.

For the year-ended December 31, 2009, Duke Energy Corporation (Duke Energy) reported net income attributable to Duke Energy of $1,075 million and basic and diluted earnings per share (EPS) of $0.83, as compared to net income attributable to Duke Energy of $1,362 million and basic and diluted EPS of $1.08 and $1.07, respectively, for the year-ended December 31, 2008. Income from continuing operations was $1,073 million for 2009 as compared to $1,275 million for 2008. Total reportable segment EBIT (defined below in "Segment Results" section of Management's Discussion and Analysis of Financial Condition and Results of Operations) decreased to $2,713 million in 2009 from $3,073 million in 2008.

See "Results of Operations" below for a detailed discussion of the consolidated results of operations, as well as a detailed discussion of EBIT results for each of Duke Energy's reportable business segments, as well as Other.

2009 Areas of Focus and Accomplishments.

In 2009, management was focused on managing through the economic recession, investing in modernization of Duke Energy's regulated infrastructure and dealing with increased competition in Ohio.

Managing Through the Economic Recession and Changing Competitive Landscapes.

In U.S. Franchised Electric and Gas, Duke Energy's largest business segment, weather-normalized electric volumes were down approximately 4% when compared to 2008. This was driven primarily by a decrease in industrial sales volumes, which were down approximately 14% compared to 2008. Although industrial sales volumes were down year over year, industrial volumes began to show signs of stabilization late in 2009. On a weather-normalized basis, residential sales volumes were slightly positive, while commercial sales volumes were slightly negative. Looking forward to 2010, management expects the load forecast to be relatively flat compared to 2009.

In 2009, Commercial Power's operations were impacted by the competitive markets in Ohio, which were triggered by low commodity prices that put downward pressure on power prices. The available capacity and lower prices provided opportunities for native load customers in Ohio to switch generation suppliers. Competitive power suppliers began supplying power to current Commercial Power native load customers in Ohio and Commercial Power experienced an increase in customer switching beginning in the second quarter of 2009. As of December 31, 2009, customer switching levels approximated 40% of Commercial Power's native load. However, through Duke Energy Retail Sales (DERS), Commercial Power acquired approximately 60% of the switched load by offering customers a discount to the Electric Security Plan (ESP) price. When factoring in the DERS activity, Commercial Power experienced net customer switching of about 15%, although those native load customers acquired by DERS were at lower margins than customers served under the ESP. Additionally, DERS has been able to acquire new customers outside Commercial Power's native load territory. As a result of lower forecasted energy prices, lower demand for electricity due to the economy and competitive pressures in Ohio, and other valuation factors, a non-cash goodwill impairment charge of approximately $371 million was recorded by Commercial Power in the third quarter of 2009.

In light of the above economic factors that impacted Duke Energy's business in 2009, management was focused on offsetting those economic pressures by successfully managing costs and achieving excellent operational performance. Duke Energy achieved significant operations and maintenance cost mitigation goals across its business segments and also reduced planned capital expenditures by approximately $200 million, which highlights Duke Energy's ability to take advantage of the flexibility within its capital spending plan. Additionally, Duke Energy's generation fleet operated at some of the highest levels in Duke Energy's history. These combined efforts allowed Duke Energy to largely mitigate the negative impact of the economy on its results of operations in 2009.

Key Regulatory Accomplishments. During 2009, Duke Energy completed the following regulatory initiatives:

- Obtained favorable rate case outcomes in North Carolina, South Carolina, Ohio and Kentucky which will increase revenues by nearly $460 million upon full implementation.
- Updated/enabled construction work-in-progress (CWIP) recovery for Duke Energy Carolinas' Cliffside Unit 6 and the Integrated Gasification Combined Cycle (IGCC) plant at Duke Energy Indiana's Edwardsport Generating Station.
- Received approval for cost recovery mechanisms for save-a-watt programs in North Carolina, South Carolina and Ohio. Approval in Indiana is anticipated in February 2010.
- Began deployment of SmartGrid in Ohio, along with the initiation of a rate rider cost recovery mechanism, which is awaiting approval and a ruling is expected in the first quarter of 2010. Additionally, Duke Energy was awarded a stimulus grant for approximately $200 million to be used for reimbursement of costs related to SmartGrid.

- Received approvals of wind, solar and other renewable energy projects, which will enable innovative renewable energy initiatives and help Duke Energy meet specific renewable energy standards over time.

Overall, the regulatory and legislative accomplishments during 2009 have positioned Duke Energy well for 2010 and beyond.

Capital Expenditures and Fleet and Grid Modernization.

Duke Energy's strategy for meeting customer demand, while building a sustainable business that allows its customers and its shareholders to prosper in a carbon-constrained environment, includes significant commitments to renewable energy, customer energy efficiency, advanced nuclear power, advanced clean-coal and high-efficiency natural gas electric generating plants, and retirement of older less efficient coal-fired power plants. Due to the likelihood of upcoming environmental regulations, including carbon legislation, air pollutant regulation by the U.S. Environmental Protection Agency (EPA) and coal regulation, Duke Energy has been focused on modernizing its fleet in preparation for a low carbon future. During 2009, Duke Energy has continued the construction of Cliffside Unit 6 in North Carolina and the Edwardsport IGCC plant in Indiana and these construction projects are approximately 55% complete and 50% complete, respectively, at December 31, 2009. Both are scheduled to be placed in service during 2012. Once in service, Duke Energy will begin retiring older, less efficient coal and gas-fired units. Additionally, Duke Energy Carolinas has begun construction on a 620 megawatt (MW) combined cycle natural gas-fired generating facility at each of its existing Buck and Dan River Steam Stations. These facilities are scheduled to be placed in service in 2011 and 2012, respectively. In conjunction with these and other capital projects, management is continuing its focus on reducing regulatory lag, which refers to the period of time between making an investment and earning a return and recovering that investment. In 2007, the Indiana Utility Regulatory Commission (IURC) approved the timely recovery of initial construction cost estimates associated with the Edwardsport IGCC plant. The 2009 rate case settlements in North Carolina and South Carolina included stipulations allowing for the recovery in base rates of financing costs related to Cliffside Unit 6, although the recovery is delayed in North Carolina for a one year period.

Duke Energy Carolinas is also continuing to seek all necessary regulatory approvals for the proposed William States Lee III Nuclear Station, including the December 2007 filings of a Combined Construction and Operating License (COL) application with the Nuclear Regulatory Commission (NRC) and requests to incur up to $230 million in development costs through 2009, which were approved in 2008. Although these actions are necessary steps as management continues to pursue the option of building a new nuclear plant, submitting these applications does not commit Duke Energy Carolinas to build a nuclear unit.

In 2009, Duke Energy made significant strides in adding to its existing renewable energy portfolio. One way Duke Energy is reducing its environmental footprint while meeting demand for reliable, clean energy is by investing in zero carbon wind power. During 2009, Commercial Power, through Duke Energy Generation Services (DEGS), brought approximately 364 MW of wind generation online through a combination of completed construction and acquisition. At December 31, 2009, DEGS had approximately 735 MW of wind generation in commercial operation. The wind assets in service have long-term power purchase agreements to sell the output to an end customer. Additionally, DEGS became an owner in a biomass development joint venture and, in early 2010, announced it would acquire a 16 MW solar development project in San Antonio, Texas.

Management is also making progress on increasing the role energy efficiency will have in meeting customers' growing energy needs. Energy efficiency is considered a "fifth fuel" in the portfolio available to meet customers' growing needs for electricity, along with coal, nuclear, natural gas and renewable energy. During 2009, Duke Energy's save-a-watt models were approved in North Carolina, South Carolina and Ohio and Duke Energy is awaiting a decision on the proposed save-a-watt model in Indiana, which is expected in the first quarter of 2010. The save-a-watt proposal in Kentucky was withdrawn and will be addressed in Duke Energy Kentucky's next general rate case.

Duke Energy Objectives — 2010 and beyond.

Duke Energy will continue to focus on operational excellence, shaping federal and state legislative and regulatory policy, continued modernization of infrastructure and investing in renewable energy, including energy efficiency. The majority of future earnings are anticipated to be contributed from U.S. Franchised Electric and Gas, which consists of Duke Energy's regulated businesses that currently own a capacity of approximately 27,000 MW of generation. The regulated generation portfolio consists of a mix of coal, nuclear, natural gas and hydroelectric generation, with the substantial majority of all of the sales of electricity coming from coal and nuclear generation facilities. The favorable rate case outcomes reached in the various jurisdictions in 2009, as discussed above, will increase U.S. Franchised Electric and Gas' revenues by approximately $460 million upon full implementation.

As a result of the downturn in the economy, Duke Energy experienced reductions in sales volumes in 2009, most notably within the industrial customer class. Management anticipates that recessionary pressures will continue in 2010, resulting in essentially flat kilowatt-hour sales in both the Carolinas and the Midwest service territories. In order to address these pressures, management is focused on containing costs in 2010 and currently expects non-recoverable (i.e., not directly recovered via a rider or other mechanism) operations and maintenance expense to be flat compared to 2009, due largely to sustainable reductions achieved during 2009, as well as certain 2010 initiatives such as a voluntary severance program and office consolidation. In addition, management will continue efforts to achieve constructive regulatory outcomes to reduce regulatory lag, including continually reviewing the need for general rate case filings in certain jurisdictions in 2010 and beyond.

Additionally, due to the competitive markets in Ohio, customer switching will continue to impact the results of the Commercial Power business, as management currently estimates that an incremental 5% of current customer load will switch to alternative suppliers in 2010. Management is focused on mitigating lost volume and margin erosion in 2010 through DERS efforts to acquire native load customers, as well as acquiring customers outside of Commercial Power's Ohio native load territory that are currently supplied by other electric generators.

During the three-year period from 2010 through 2012, Duke Energy anticipates total capital expenditures of approximately $14 billion to $15 billion. Of this amount, approximately $5.7 billion is expected to be spent on committed projects, including base load power plants to meet long-term growth in customer demand and to modernize the generation fleet, ongoing environmental projects, and nuclear fuel. Approximately $6.8 billion of capital expenditures are expected to be used primarily for overall system maintenance, customer connections, and corporate expenditures. Although these expenditures are ultimately necessary to ensure overall system maintenance and reliability, the timing of the expenditures may be influenced by broad economic conditions and customer growth. The remaining estimated capital expenditures of approximately $1.2 billion to $2.7 billion are of a discretionary nature and relate to growth opportunities in which Duke Energy may invest, provided there are opportunities to meet return expectations along with assurance of constructive regulatory treatment in the regulated businesses. Discretionary capital primarily includes Commercial Power renewable and transmission projects, projects at International Energy and renewable projects at U.S. Franchised Electric and Gas. Capital expenditures are currently estimated to be approximately $5.2 billion in 2010. These expenditures are principally related to expansion plans, maintenance costs, environmental spending related to Clean Air Act (CAA) requirements and nuclear fuel. Duke Energy is committed to adding base load capacity at a reasonable price while modernizing the current generation facilities by replacing older, less efficient plants with cleaner, more efficient plants. Significant expansion projects include the Edwardsport IGCC plant, an 825 MW coal unit at Duke Energy Carolinas' existing Cliffside facility and new gas-fired generation units at Duke Energy Carolinas' existing Dan River and Buck Steam Stations, as well as other additions due to system growth. Additionally, Duke Energy is evaluating the potential construction of the William States Lee III nuclear power plant in Cherokee County, South Carolina.

Duke Energy anticipates capital expenditures at Commercial Power will primarily relate to growth opportunities, such as renewable energy generation projects and environmental control equipment, as well as maintenance on existing plants. Capital expenditures at International Energy, which will be funded with cash held or raised by International Energy, will primarily be for strategic growth opportunities, as well as maintenance on existing plants.

With the exception of equity issuances to fund the dividend reinvestment plan and other internal plans, Duke Energy does not currently anticipate the issuance of any other common equity in the foreseeable future. Duke Energy expects to have access to liquidity in the capital markets at reasonable rates and terms in 2010. Additionally, Duke Energy has access to unsecured revolving credit facilities, which are not restricted upon general market conditions, with aggregate bank commitments of approximately $3.14 billion. At December 31, 2009, Duke Energy has available borrowing capacity of approximately $1.9 billion under this facility. For further information related to management's assessment of liquidity and capital resources, including known trends and uncertainties, see "Liquidity and Capital Resources" below.

As the majority of Duke Energy's anticipated future capital expenditures are related to its regulated operations, a risk to Duke Energy is the ability to recover costs related to such expansion in a timely manner. Energy legislation passed in North Carolina and South Carolina in 2007 provides, among other things, mechanisms for Duke Energy to recover financing costs for new nuclear or coal base load generation during the construction phase. In Indiana, Duke Energy has received approval to recover its development costs for the new IGCC plant at the Edwardsport Generating Station. Duke Energy has received approval for nearly $260 million of future federal tax credits related to costs to be incurred for the modernization of Cliffside Unit 6, as well as the IGCC plant in Indiana. In addition, Duke Energy has received general assurances from the North Carolina Utilities Commission (NCUC) that the North Carolina allocable portion of development costs associated with the William States Lee III nuclear station will be recoverable through a future rate case proceeding as long as the costs are deemed prudent and reasonable. Duke Energy does not anticipate beginning construction of the proposed nuclear power plant without adequate assurance of cost recovery from the state legislators or regulators.

In summary, Duke Energy is coordinating its future capital expenditure requirements with regulatory initiatives in order to ensure adequate and timely cost recovery while continuing to provide low cost energy to its customers.

Economic Factors for Duke Energy's Business.

Duke Energy's business model provides diversification between stable regulated businesses like U.S. Franchised Electric and Gas and certain portions of Commercial Power's operations, and the traditionally higher-growth businesses like the unregulated portion of Commercial Power's operations and International Energy. As was the case throughout much of 2009, all of Duke Energy's businesses can be negatively affected by sustained downturns or sluggishness in the economy, including low market prices of commodities, all of which are beyond Duke Energy's control, and could impair Duke Energy's ability to meet its goals for 2010 and beyond.

As Duke Energy experienced in 2009, declines in demand for electricity as a result of economic downturns reduce overall electricity sales and have the potential to lessen Duke Energy's cash flows, especially as industrial customers reduce production and, thus, consumption of electricity. A weakening economy could also impact Duke Energy's customer's ability to pay, causing increased delinquencies, slowing collections and lead to higher than normal levels of accounts receivables, bad debts and financing requirements. A portion of U.S. Franchised Electric and Gas' business risk is mitigated by its regulated allowable rates of return and recovery of fuel costs under fuel adjustment clauses. The ESP in Ohio also helps mitigate a portion of the risk associated with certain portions of Commercial Power's generation operations by providing mechanisms for recovery of certain costs associated with, among other things, fuel and purchased power for native-load customers.

If negative market conditions should persist over time and estimated cash flows over the lives of Duke Energy's individual assets, including goodwill, do not exceed the carrying value of those individual assets, asset impairments may occur in the future under existing accounting rules and diminish results of operations. A change in management's intent about the use of individual assets (held for use versus held for sale) could also result in impairments or losses.

Duke Energy's 2010 goals can also be substantially at risk due to the regulation of its businesses. Duke Energy's businesses in the United States (U.S.) are subject to regulation on the federal and state level. Regulations, applicable to the electric power industry, have a significant impact on the nature of the businesses and the manner in which they operate. New legislation and changes to regulations are ongoing, including anticipated carbon legislation, and Duke Energy cannot predict the future course of changes in the regulatory or political environment or the ultimate effect that any such future changes will have on its business.

Duke Energy's earnings are impacted by fluctuations in commodity prices. Exposure to commodity prices generates higher earnings volatility in the unregulated businesses as there are timing differences as to when such costs are recovered in rates. To mitigate these risks, Duke Energy enters into derivative instruments to effectively hedge some, but not all, known exposures.

Additionally, Duke Energy's investments and projects located outside of the United States expose Duke Energy to risks related to laws of other countries, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. Changes in these factors are difficult to predict and may impact Duke Energy's future results.

Duke Energy also relies on access to both short-term money markets and longer-term capital markets as a source of liquidity for capital requirements not met by cash flow from operations. An inability to access capital at competitive rates or at all could adversely affect Duke Energy's ability to implement its strategy. Market disruptions or a downgrade of Duke Energy's credit rating may increase its cost of borrowing or adversely affect its ability to access one or more sources of liquidity. Additionally, there are no assurances that commitments made by lenders under Duke Energy's credit facilities will be available if needed as a source of funding due to ongoing uncertainties in the financial services industry.

For further information related to management's assessment of Duke Energy's risk factors, see Item 1A. "Risk Factors."

RESULTS OF OPERATIONS

Consolidated Operating Revenues

Year Ended December 31, 2009 as Compared to December 31, 2008. Consolidated operating revenues for 2009 decreased approximately $476 million compared to 2008. This change was primarily driven by the following:

- An approximate $726 million decrease at U.S. Franchised Electric and Gas. See Operating Revenue discussion within "Segment Results" for U.S. Franchised Electric and Gas below for further information; and
- An approximate $27 million decrease at International Energy. See Operating Revenue discussion within "Segment Results" for International Energy below for further information.

Partially offsetting these decreases was:

- An approximate $288 million increase at Commercial Power. See Operating Revenue discussion within "Segment Results" for Commercial Power below for further information.

Year Ended December 31, 2008 as Compared to December 31, 2007. Consolidated operating revenues for 2008 increased approximately $487 million compared to 2007. This change was primarily driven by the following:

- An approximate $419 million increase at U.S. Franchised Electric and Gas. See Operating Revenue discussion within "Segment Results" for U.S. Franchised Electric and Gas below for further information; and
- An approximate $125 million increase at International Energy. See Operating Revenue discussion within "Segment Results" for International Energy below for further information.

Partially offsetting these increases was:

- An approximate $55 million decrease at Commercial Power. See Operating Revenue discussion within "Segment Results" for Commercial Power below for further information.

Consolidated Operating Expenses

Year Ended December 31, 2009 as Compared to December 31, 2008. Consolidated operating expenses for 2009 decreased approximately $247 million compared to 2008. This change was driven primarily by the following:

- An approximate $626 million decrease at U.S. Franchised Electric and Gas. See Operating Expense discussion within "Segment Results" for U.S. Franchised Electric and Gas below for further information;
- An approximate $65 million decrease at International Energy. See Operating Expense discussion within "Segment Results" for International Energy below for further information; and
- An approximate $40 million decrease at Other. See Operating Expense discussion within "Segment Results" for Other below for further information.

Partially offsetting these decreases was:

- An approximate $489 million increase at Commercial Power, which includes approximately $413 million of impairment charges in 2009 primarily related to a goodwill impairment charge associated with the non-regulated generation operations in the Midwest. See Operating Expense discussion within "Segment Results" for Commercial Power below for further information.

Year Ended December 31, 2008 as Compared to December 31, 2007. Consolidated operating expenses for 2008 increased approximately $543 million compared to 2007. This change was driven primarily by the following:

- An approximate $401 million increase at U.S. Franchised Electric and Gas. See Operating Expense discussion within "Segment Results" for U.S. Franchised Electric and Gas below for further information;
- An approximate $123 million increase at International Energy. See Operating Expense discussion within "Segment Results" for International Energy below for further information; and
- An approximate $27 million increase at Commercial Power. See Operating Expense discussion within "Segment Results" for Commercial Power below for further information.

Consolidated Gains (Losses) on Sales of Other Assets and Other, net

Consolidated gains (losses) on sales of other assets and other, net was a gain of approximately $36 million and $69 million in 2009 and 2008, respectively, and a loss of approximately $5 million for 2007. The gains and losses for all years relate primarily to sales of emission allowances by U.S. Franchised Electric and Gas and Commercial Power.

Consolidated Operating Income

Year Ended December 31, 2009 as Compared to December 31, 2008. For 2009, consolidated operating income decreased approximately $262 million compared to 2008. Drivers to operating income are discussed above.

Year Ended December 31, 2008 as Compared to December 31, 2007. For 2008, consolidated operating income increased approximately $18 million compared to 2007. Drivers to operating income are discussed above.

Other drivers to operating income are discussed above. For more detailed discussions, see the segment discussions that follow.

Consolidated Other Income and Expenses

Year Ended December 31, 2009 as Compared to December 31, 2008. For 2009, consolidated other income and expenses increased approximately $212 million compared to 2008. This increase was primarily driven by an increase in equity earnings of approximately $172 million due mostly to impairment charges recorded by Crescent JV (Crescent) in 2008, of which Duke Energy's proportionate share was approximately $238 million, partially offset by decreased equity earnings from International Energy of approximately $55 million primarily related to lower contributions from its investment in National Methanol Company (NMC) and losses from its investment in Attiki Gas Supply S.A. (Attiki). Also, the mark-to-market and investment income on investments that support benefit obligations and within the captive insurance portfolio increased approximately $45 million as a result of gains in 2009 compared to losses in 2008. Additionally, foreign exchange impacts, primarily related to the remeasurement of certain U.S. dollar denominated cash and debt balances at International Energy, resulted in gains in 2009 compared to losses in 2008 due to favorable foreign exchange rates, resulting in an increase of approximately $43 million in 2009 compared to 2008. Partially offsetting these increases was decreased interest income of approximately $53 million due primarily to lower average cash and short-term investment balances, an approximate $26 million charge in 2009 related to certain performance guarantees Duke Energy had issued on behalf of Crescent and an approximate $18 million impairment charge in 2009 to write down the carrying value of International Energy's investment in Attiki to its fair value.

Year Ended December 31, 2008 as Compared to December 31, 2007. For 2008, consolidated other income and expenses decreased approximately $307 million compared to 2007. This decrease was primarily driven by a decrease in equity earnings of approximately $259 million due primarily to impairment charges recorded by Crescent, of which Duke Energy's proportionate share was approximately $238 million, partially offset by increased equity earnings from International Energy of approximately $25 million primarily related to its investment in NMC primarily as a result of higher margins, an approximate $62 million decrease in interest income primarily due to favorable income tax settlements in 2007 and lower earnings on invested cash and short-term investment balances during 2008 as compared to 2007, an approximate $54 million decrease due to unfavorable investment returns and an approximate $34 million decrease associated with foreign currency losses due primarily to losses in 2008 associated with the remeasurement of certain U.S. dollar denominated cash and debt balances at International Energy, partially offset by an approximate $80 million increase in the equity component of allowance for funds used during construction (AFUDC) as a result of increased capital spending and the absence of convertible debt charges of approximately $21 million recognized in 2007 related to the spin-off of Spectra Energy Corp. (Spectra Energy).

Consolidated Interest Expense

Year Ended December 31, 2009 as Compared to December 31, 2008. Consolidated interest expense increased approximately $10 million in 2009 as compared to 2008. This increase is primarily attributable to higher debt balances, partially offset by lower average interest rates on floating rate debt and commercial paper balances.

Year Ended December 31, 2008 as Compared to December 31, 2007. Consolidated interest expense increased approximately $56 million in 2008 as compared to 2007. This increase is primarily attributable to higher debt balances, partially offset by a higher debt component of AFUDC and capitalized interest due to increased capital spending.

Consolidated Income Tax Expense from Continuing Operations

Year Ended December 31, 2009 as Compared to December 31, 2008. For 2009, consolidated income tax expense from continuing operations increased approximately $142 million compared to 2008. Although pre-tax income was lower in 2009 compared to 2008, the effective tax rate for the year ended December 31, 2009 was approximately 41% compared to 33% for the year ended December 31, 2008 due primarily to an approximate $371 million non-deductible goodwill impairment charge in 2009.

Year Ended December 31, 2008 as Compared to December 31, 2007. For 2008, consolidated income tax expense from continuing operations decreased approximately $96 million compared to 2007. This decrease primarily resulted from lower pre-tax income in 2008 compared to 2007. The effective tax rate for the year ended December 31, 2008 increased to approximately 33% compared to 32% for the year ended December 31, 2007. The increase in the effective tax rate during 2008 is primarily attributable to adjustments related to prior year tax returns, an increase in foreign taxes, a decrease in the manufacturing deduction and a deferred state tax benefit recorded in 2007 partially offset by higher AFUDC equity and a tax benefit recorded for certain foreign restructurings.

Consolidated Income (Loss) from Discontinued Operations, net of tax

Consolidated income (loss) from discontinued operations was income of approximately $12 million and $16 million for 2009 and 2008, respectively, and a loss of $22 million for 2007. The 2008 amount is primarily comprised of Commercial Power's sale of its 480 MW natural gas-fired peaking generating station located near Brownsville, Tennessee to Tennessee Valley Authority, which resulted in an approximate $15 million after-tax gain.

The 2007 amount is primarily comprised of an after-tax loss of approximately $18 million associated with former Duke Energy North America (DENA) contract settlements, an after-tax loss of approximately $8 million related to Cinergy Corp. (Cinergy) commercial marketing and trading operations and after-tax earnings of approximately $23 million related to Commercial Power's synfuel operations.

Extraordinary Item, net of tax

The reapplication of regulatory accounting treatment to certain of Commercial Power's operations on December 17, 2008 resulted in an approximate $67 million after-tax (approximately $103 million pre-tax) extraordinary gain related to total mark-to-market losses previously recorded in earnings associated with open forward native load economic hedge contracts for fuel, purchased power and emission allowances, which the ESP allows to be recovered through a fuel and purchased power rider.

Segment Results

Management evaluates segment performance based on earnings before interest and taxes from continuing operations (excluding certain allocated corporate governance costs), after deducting amounts attributable to noncontrolling interests related to those profits (EBIT). On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the amounts attributable to noncontrolling interests related to those profits. Cash, cash equivalents and short-term investments are managed centrally by Duke Energy, so interest and dividend income on those balances, as well as gains and losses on remeasurement of foreign currency denominated balances, are excluded from the segments' EBIT. Management considers segment EBIT to be a good indicator of each segment's operating performance from its continuing operations, as it represents the results of Duke Energy's ownership interest in operations without regard to financing methods or capital structures.

See Note 2 to the Consolidated Financial Statements, "Business Segments," for a discussion of Duke Energy's segment structure.

Duke Energy's segment EBIT may not be comparable to a similarly titled measure of another company because other entities may not calculate EBIT in the same manner. Segment EBIT is summarized in the following table, and detailed discussions follow.

EBIT by Business Segment

	Years Ended December 31,				
(in millions)	2009	2008	Variance 2009 vs. 2008	2007	Variance 2008 vs. 2007
U.S. Franchised Electric and Gas	$2,321	$2,398	$ (77)	$2,305	$ 93
Commercial Power	27	264	(237)	278	(14)
International Energy	365	411	(46)	388	23
Total reportable segment EBIT	2,713	3,073	(360)	2,971	102
Other	(251)	(568)	317	(260)	(308)
Total reportable segment EBIT and other	2,462	2,505	(43)	2,711	(206)
Interest expense	(751)	(741)	10	(685)	56
Interest income and other[a]	102	117	(15)	201	(84)
Add back of noncontrolling interest component of reportable segment and Other EBIT	18	10	8	9	1
Consolidated earnings from continuing operations before income taxes	$1,831	$1,891	$ (60)	$2,236	$(345)

(a) Other within Interest income and other includes foreign currency transaction gains and losses and additional noncontrolling interest amounts not allocated to reportable segment and Other EBIT.

Noncontrolling interest amounts presented below includes only expenses and benefits related to EBIT of Duke Energy's joint ventures. It does not include the noncontrolling interest component related to interest and taxes of the joint ventures.

Segment EBIT, as discussed below, includes intercompany revenues and expenses that are eliminated in the Consolidated Financial Statements.

U.S. Franchised Electric and Gas

U.S. Franchised Electric and Gas includes the regulated operations of Duke Energy Carolinas, LLC (Duke Energy Carolinas), Duke Energy Indiana, Inc. (Duke Energy Indiana), and Duke Energy Kentucky, Inc. (Duke Energy Kentucky) and certain regulated operations of Duke Energy Ohio, Inc. (Duke Energy Ohio).

	Years Ended December 31,				
(in millions, except where noted)	2009	2008	Variance 2009 vs. 2008	2007	Variance 2008 vs. 2007
Operating revenues	$ 9,433	$10,159	$ (726)	$ 9,740	$ 419
Operating expenses	7,263	7,889	(626)	7,488	401
Gains (losses) on sales of other assets and other, net	20	6	14	—	6
Operating income	2,190	2,276	(86)	2,252	24
Other income and expenses, net	131	122	9	53	69
EBIT	$ 2,321	$ 2,398	$ (77)	$ 2,305	$ 93
Duke Energy Carolinas' GWh sales[a]	79,830	85,476	(5,646)	86,604	(1,128)
Duke Energy Midwest GWh sales[a][b]	56,753	62,523	(5,770)	64,570	(2,047)
Net proportional MW capacity in operation[c]	26,957	27,438	(481)	27,586	(148)

(a) Gigawatt-hours (GWh).
(b) Duke Energy Ohio (Ohio transmission and distribution only), Duke Energy Indiana and Duke Energy Kentucky collectively referred to as Duke Energy Midwest within this U.S. Franchised Electric and Gas segment discussion.
(c) Megawatt (MW).

The following table shows the percent changes in GWh sales and average number of customers for Duke Energy Carolinas

Increase (decrease) over prior year	2009	2008	2007
Residential sales[a]	(0.2)%	(0.5)%	6.5%
General service sales[a]	(1.1)%	(0.5)%	5.4%
Industrial sales[a]	(15.2)%	(5.5)%	(2.3)%
Wholesale sales	(31.6)%	11.9%	40.9%
Total Duke Energy Carolinas' sales[b]	(6.6)%	(1.3)%	4.8%
Average number of customers	0.5%	1.5%	2.0%

(a) Major components of Duke Energy Carolinas' retail sales.
(b) Consists of all components of Duke Energy Carolinas' sales, including retail sales, and wholesale sales to incorporated municipalities and to public and private utilities and power marketers.

The following table shows the percent changes in GWh sales and average number of customers for Duke Energy Midwest.

Increase (decrease) over prior year	2009	2008	2007
Residential sales[a]	(4.3)%	(3.0)%	6.7%
General service sales[a]	(3.5)%	(1.2)%	6.3%
Industrial sales[a]	(15.0)%	(6.5)%	(0.4)%
Wholesale sales	(20.8)%	1.5%	7.7%
Total Duke Energy Midwest's sales[b]	(9.2)%	(3.2)%	4.5%
Average number of customers	(0.3)%	0.3%	0.8%

(a) Major components of Duke Energy Midwest's retail sales.
(b) Consists of all components of Duke Energy Midwest's sales, including retail sales, and wholesale sales to incorporated municipalities and to public and private utilities and power marketers.

Year Ended December 31, 2009 as Compared to December 31, 2008

Operating Revenues.

The decrease was driven primarily by:

- A $536 million decrease in fuel revenues (including emission allowances) driven primarily by decreased demand from retail and near-term wholesale customers and lower natural gas fuel rates primarily in Ohio and Kentucky, partially offset by higher fuel rates for electric retail customers. Fuel revenues represent sales to both retail and wholesale customers;
- A $117 million decrease due to lower weather normalized sales volumes to retail customers largely reflecting the overall declining economic conditions in 2009, which primarily impacted the industrial sector;
- A $63 million decrease in GWh and thousand cubic feet (Mcf) sales to retail customers due to overall milder weather conditions in 2009 compared to 2008. Weather statistics for heating degree days in 2009 were unfavorable in the Midwest but favorable in the Carolinas compared to 2008. Weather statistics for cooling degree days in 2009 were unfavorable in both the Midwest and Carolinas compared to 2008; and
- A $30 million net decrease in wholesale power revenues, net of sharing, primarily due to decreased sales volumes and lower prices on near-term sales as a result of weak market conditions, partially offset by higher prices and increased sales volumes to customers served under certain long-term contracts.

Partially offsetting these decreases was:

- A $31 million net increase in retail rates and rate riders primarily due to increases in recoveries of Duke Energy Indiana's environmental compliance costs and the IGCC rider, partially offset by the expiration of the one-time increment rider related to merger savings that was included in North Carolina retail rates in 2008.

Operating Expenses.

The decrease was driven primarily by:

- A $541 million decrease in fuel expense (including purchased power and natural gas purchases for resale) primarily due to a lower volume of coal used in electric generation, lower prices and volumes for natural gas purchased for resale and used in electric generation and reduced purchased power, partially offset by higher coal prices;
- A $71 million decrease in operating and maintenance expenses primarily due to lower scheduled outage and maintenance costs at nuclear and fossil generating stations, lower power and gas delivery maintenance and decreased capacity costs due to the expiration of certain drought mitigation contracts in 2008, partially offset by higher benefits costs; and
- A $36 million decrease in depreciation and amortization due primarily to lower depreciation rates in the Carolinas, partially offset by increases in depreciation due primarily to additional capital spending.

Partially offsetting these decreases was:

- A $22 million increase in property and other taxes due primarily to normal increases.

Gains (Losses) on Sales of Other Assets and Other, net.

The increase is primarily due to gains on the sale of nitrogen oxide (NO_x) emission allowances in 2009.

Other Income and Expenses, net.

The increase is due primarily to a higher equity component of AFUDC earned from additional capital spending for ongoing construction projects, partially offset by a favorable 2008 IURC ruling.

EBIT.

The decrease resulted primarily from lower weather adjusted sales volumes, milder weather, lower wholesale power revenues, higher benefits costs and higher property and other taxes. These negative impacts were partially offset by decreased operation and maintenance costs as a result of lower outage and maintenance costs, lower depreciation rates in the Carolinas and overall net higher rates and rate riders.

Matters Impacting Future U.S. Franchised Electric and Gas Results

U.S. Franchised Electric and Gas continues to increase the overall number of retail customers served, maintain low costs and deliver high-quality customer service in the Carolinas and Midwest; however, sales to all retail customer classes were negatively impacted by the economic downturn in 2009, particularly sales to the industrial sector. These trends are expected to continue for some period into 2010, and perhaps beyond, until the economy begins to recover. The general decline in the textile industry in the Carolinas, exacerbated by the struggling economy, is also expected to continue in 2010, fueled by the expiration of certain import limitations related to foreign textile products.

U.S. Franchised Electric and Gas evaluates the carrying amount of its recorded goodwill for impairment on an annual basis as of August 31 and performs interim impairment assessments if a triggering event occurs that indicates it is more likely than not that the fair value of a reporting unit is less than its carrying value. For further information on key assumptions that impact U.S. Franchised Electric and Gas' goodwill impairment assessments, see Critical Accounting Policy for Goodwill Impairment Assessments. As of the date of the 2009 annual impairment analysis, the fair value of U.S. Franchised Electric and Gas' reporting units exceeded their respective carrying value, thus no goodwill impairment charges were recorded. However, the fair value of the Ohio Transmission and Distribution reporting unit (Ohio T&D), which had a goodwill balance of approximately $700 million as of December 31, 2009, exceeded the carrying value of equity by less than 15%. Management is continuing to monitor the impact of recent market and economic events to determine if it is more likely than not that the carrying value of the Ohio T&D reporting unit has been impaired. Should any such triggering events or circumstances occur in 2010 that would more likely than not reduce the fair value of the Ohio T&D reporting unit below its carrying value, management would perform an interim impairment assessment of the Ohio T&D goodwill and it is possible that a goodwill impairment charge could be recorded as a result of this assessment. Potential circumstances that could have a negative effect on the fair value of the Ohio T&D reporting unit include additional declines in load volume forecasts, changes in the weighted average cost of capital (WACC), changes in the timing and/or recovery of and on investments in SmartGrid technology, and the success of future rate case filings.

Year Ended December 31, 2008 as Compared to December 31, 2007

Operating Revenues.

The increase was driven primarily by:

- A $474 million increase in fuel revenues (including emission allowances) driven primarily by higher fuel rates in all regions and legislative changes that allow Duke Energy Carolinas to collect additional purchased power and environmental compliance costs from retail customers. Fuel revenues represent sales to both retail and wholesale customers; and
- A $92 million increase related to substantial completion in 2007 of the sharing of anticipated merger savings through rate decrement riders with regulated customers.

Partially offsetting these increases were:

- A $73 million decrease in weather adjusted sales volumes to retail customers reflecting the overall declining economic conditions, which are primarily impacting the industrial sector;
- A $53 million decrease in retail rates and rate riders primarily related to the new retail base rates implemented in North Carolina in the first quarter of 2008, net of increases in recoveries of Duke Energy Indiana's environmental compliance costs from retail customers and higher gas base rates implemented in the second quarter of 2008 for Duke Energy Ohio; and
- A $49 million decrease in GWh and Mcf sales to retail customers due to milder weather in 2008 compared to 2007. While weather statistics for heating degree days in 2008 were favorable compared to 2007, this favorable impact was more than offset by the impact of fewer cooling degree days in 2008 compared to 2007.

Operating Expenses.

The increase was driven primarily by:

- A $441 million increase in fuel expense (including purchased power and natural gas purchases for resale) primarily due to higher coal and natural gas prices and increased purchased power. This increase also reflects a $21 million reimbursement in first quarter 2007 of previously incurred fuel expenses resulting from a settlement between Duke Energy Carolinas and U.S. Department of Justice (DOJ) resolving Duke Energy Carolinas' used nuclear fuel litigation against the Department of Energy (DOE). The settlement between the parties was finalized on March 5, 2007;
- A $67 million increase in depreciation due primarily to additional capital spending; and
- A $66 million increase in operating and maintenance expenses primarily due to higher scheduled outage and maintenance costs at nuclear and fossil generating plants, storm costs primarily in the Midwest related to Hurricane Ike in September 2008 net of deferral of a portion of the Ohio and Kentucky storm costs associated with Hurricane Ike, increased capacity costs due to additional contracts that were entered into in late 2007 to ensure customer electricity needs were met despite ongoing drought conditions and increased power delivery maintenance charges to increase system reliability, partially offset by lower benefit costs including short-term incentives.

Partially offsetting these increases was:

- A $170 million decrease in regulatory amortization expenses, including approximately $187 million for the amortization of compliance costs related to North Carolina clean air legislation, which was completed in 2007. This decrease was partially offset by the write-off in 2007 of a portion of the investment in the GridSouth Regional Transmission Organization (RTO) (approximately $17 million) per a rate order from the NCUC.

Other Income and Expenses, net.

The increase is due primarily to the equity component of AFUDC due to additional capital spending for ongoing construction projects and a favorable $25 million IURC ruling.

EBIT.

The increase resulted primarily from decreased regulatory amortization, the substantial completion of the required rate reductions due to the merger with Cinergy and increased AFUDC. These increases were partially offset by the impacts of the unfavorable economy on sales, milder weather, additional depreciation as rate base increased during 2008, higher operation and maintenance costs, overall net lower retail rates and rate riders, and the 2007 DOE settlement.

Commercial Power

	Years Ended December 31,				
(in millions, except where noted)	2009	2008	Variance 2009 vs. 2008	2007	Variance 2008 vs. 2007
Operating revenues	$ 2,114	$ 1,826	$ 288	$ 1,881	$ (55)
Operating expenses	2,134	1,645	489	1,618	27
Gains (losses) on sales of other assets and other, net	12	59	(47)	(7)	66
Operating income	(8)	240	(248)	256	(16)
Other income and expenses, net	35	24	11	22	2
EBIT	$ 27	$ 264	$ (237)	$ 278	$ (14)
Actual plant production, GWh	26,962	20,199	(6,763)	23,702	(3,503)
Net proportional megawatt capacity in operation	8,005	7,641	364	8,019	(378)

Year Ended December 31, 2009 as compared to December 31, 2008

Operating Revenues.

The increase was primarily driven by:

- A $98 million increase in retail electric revenues resulting from higher retail pricing principally related to implementation of the ESP in 2009 and the timing of fuel and purchased power rider collections in 2008, net of lower sales volumes driven by the economy and increased customer switching levels;
- A $70 million increase in net mark-to-market revenues on non-qualifying power and capacity hedge contracts, consisting of mark-to-market losses of $2 million in 2009 compared to losses of $72 million in 2008;
- A $68 million increase in revenues due to higher generation volumes and increased PJM capacity revenues from the Midwest gas-fired assets in 2009 compared to 2008;
- A $48 million increase in wholesale electric revenues due to higher generation volumes and hedge realization in 2009 compared to 2008 and margin earned from participation in wholesale auctions in 2009; and
- A $25 million increase in wind generation revenues due to commencement of operations of wind facilities in the third quarter of 2008 and additional wind generation facilities placed in service in 2009.

Operating Expenses.

The increase was primarily driven by:

- A $413 million impairment charge primarily related to goodwill associated with non-regulated generation operations in the Midwest;
- A $55 million increase in fuel expense due to mark-to-market losses on non-qualifying fuel hedge contracts, consisting of mark-to-market losses of $58 million in 2009 compared to losses of $3 million in 2008;
- A $44 million increase in depreciation and administrative expenses associated with wind projects placed in service in the third quarter of 2008 and throughout 2009, as well as the continued development of the renewable business in 2009;
- A $36 million increase in operating expenses resulting from depreciation expense on environmental projects placed in service in the second half of 2008 and higher plant maintenance expenses resulting from increased plant outages in 2009 compared to 2008;
- A $29 million increase in retail and wholesale fuel expense due to higher purchased power expenses and higher long-term contract prices and lower realized gains on fuel hedges in 2009 compared to 2008; and

- A $10 million increase in fuel and operating expenses for the Midwest gas-fired assets primarily due to higher generation volumes in 2009 compared to 2008, partially offset by bad debt reserves recorded in 2008 associated with the Lehman Brothers bankruptcy.

Partially offsetting these increases was:

- An $82 million impairment of emission allowances due to the invalidation of the Clean Air Interstate Rule (CAIR) in July 2008.

Gains (Losses) on Sales of Other Assets and Other, net.

The decrease in 2009 compared to 2008 is attributable to lower gains on sales of emission allowances.

Other Income and Expenses, net.

The increase in 2009 compared to 2008 is attributable to higher equity earnings of unconsolidated affiliates in 2009 primarily as a result of a full year of equity earnings from investments held by Catamount Energy Corporation (Catamount). Catamount, which is a leading wind power company, was acquired in September 2008. Partially offsetting this increase was a 2009 impairment charge to the carrying value of an equity method investment.

EBIT.

The decrease is primarily attributable to higher impairment charges in 2009 primarily due to a goodwill impairment charge, partially offset by a 2008 impairment charge related to emission allowance, increased plant maintenance expenses and fewer gains on sales of emission allowances. These factors were partially offset by higher retail revenue pricing as a result of implementation of the ESP, higher margins from the Midwest gas-fired assets due to increased generation volumes and PJM capacity revenues.

Matters Impacting Future Commercial Power Results

Commercial Power's current strategy is focused on maintaining its competitive position in Ohio, maximizing the returns and cash flows from its current portfolio, as well as growing its non-regulated renewable energy portfolio. Results for Commercial Power are sensitive to changes in power supply, power demand, fuel and power prices and weather, as well as dependent upon completion of energy asset construction projects and tax credits on renewable energy production.

Recently, low commodity prices have put downward pressure on power prices. The available capacity and lower prices have provided opportunities for customers in Ohio to switch generation suppliers. Competitive power suppliers have begun supplying power to current Commercial Power customers in Ohio and Commercial Power has experienced an increase in customer switching in the second half of 2009. Customer switching is anticipated to continue in 2010 and could have a significant impact on Commercial Power's results. Additionally, these evolving market conditions may potentially impact Commercial Power's ability to continue to apply regulatory accounting treatment to certain portions of its Commercial Power business segment. As of December 31, 2009, Commercial Power had regulatory assets of approximately $163 million related to under-collections under its ESP and mark-to-market losses on certain economic hedges.

As discussed in Note 11 to the Consolidated Financial Statements, "Goodwill and Intangible Assets," Commercial Power recorded an impairment charge in the third quarter of 2009 of approximately $371 million within its non-regulated generation reporting unit to write down the goodwill to its implied fair value. As a result of this impairment charge, the carrying value of goodwill associated with the non-regulated generation reporting unit of approximately $520 million is equivalent to its implied fair value. This impairment charge was based on a number of factors, including a decline in load forecast, depressed market power prices, customer switching and carbon emission legislation and/or EPA regulation developments. Should the assumptions used related to these factors change in the future as a result of then market conditions, as well as any acceleration in the timing of carbon emission legislation/EPA regulation developments, it is possible that further goodwill impairment charges could be recorded. For further information on key assumptions that impact Commercial Power's goodwill impairment assessments, see Critical Accounting Policy for Goodwill Impairment Assessments.

Year Ended December 31, 2008 as compared to December 31, 2007

Operating Revenues.

The decrease was primarily driven by:

- A $21 million decrease in wholesale electric revenues due to lower hedge realization and lower generation volumes primarily resulting from increased plant outages in 2008 compared to 2007;
- A $20 million decrease in net mark-to-market revenues on non-qualifying power and capacity hedge contracts, consisting of mark-to-market losses of $72 million in 2008 compared to losses of $52 million in 2007; and
- A $17 million decrease in revenues due to lower generation volumes from the Midwest gas-fired assets resulting from milder weather net of increased PJM capacity revenues in 2008 compared to 2007.

Operating Expenses.

The increase was primarily driven by:

- An $82 million impairment of emission allowances due to the invalidation of the CAIR in July 2008;
- A $68 million increase in fuel expense due to mark-to-market losses on non-qualifying fuel hedge contracts, consisting of mark-to-market losses of $3 million in 2008 compared to gains of $65 million in 2007; and
- A $14 million increase in plant maintenance expenses resulting from increased plant outages in 2008 compared to 2007.

Partially offsetting these increases were:

- A $63 million decrease in emission allowance expenses due to lower cost basis emission allowances consumed and lower overall emission allowance consumption due to installation of flue gas desulfurization equipment and lower generation volumes due to increased plant outages in 2008 compared to 2007;
- A $46 million decrease in net fuel and purchased power expense for retail load due to realized gains on fuel hedges partially offset by higher purchased power as a result of increased plant outages in 2008 compared to 2007; and
- A $24 million decrease in fuel and operating expenses for the Midwest gas-fired assets primarily due to lower generation volumes and lower amortization of locked-in hedge losses in 2008 compared to 2007, net of an approximate $15 million bad debt reserve related to the Lehman Bros. bankruptcy and higher plant maintenance expenses.

Gains (Losses) on Sales of Other Assets and Other, net.

The increase in 2008 as compared to 2007 is attributable to gains on sales of emission allowances in 2008 compared to losses on sales of emission allowances in 2007. Gains in 2008 were a result of sales of zero cost basis emission allowances, while losses in 2007 were as a result of sales of emission allowances acquired in connection with Duke Energy's merger with Cinergy in 2006 which were written up to fair value as part of purchase accounting.

EBIT.

The decrease is primarily attributable to higher mark-to-market losses on economic hedges due to decreasing commodity prices, the impairment of emission allowances, lower retail and wholesale revenues resulting from lower volumes due to the weakening economy and plant outages. Partially offsetting these decreases were gains on sales of zero cost basis emission allowances, lower emission allowance expense due to lower cost basis emission allowances consumed and lower consumption due to installation of flue gas desulfurization equipment and lower purchase accounting expense primarily due to the Rate Stabilization Plan (RSP) valuation.

International Energy

	Years Ended December 31,				
(in millions, except where noted)	2009	2008	Variance 2009 vs. 2008	2007	Variance 2008 vs. 2007
Operating revenues	$ 1,158	$ 1,185	$ (27)	$ 1,060	$125
Operating expenses	834	899	(65)	776	123
Gains (losses) on sales of other assets and other, net	—	1	(1)	—	1
Operating income	324	287	37	284	3
Other income and expenses, net	63	146	(83)	114	32
Expense attributable to noncontrolling interest	22	22	—	10	12
EBIT	$ 365	$ 411	$ (46)	$ 388	$ 23
Sales, GWh	19,978	18,066	1,912	17,127	939
Net proportional megawatt capacity in operation	4,053	4,018	35	3,968	50

Year Ended December 31, 2009 as Compared to December 31, 2008

Operating Revenues.

The decrease was driven primarily by:

- A $41 million decrease in Peru due to unfavorable average hydrocarbon and spot prices; and
- A $16 million decrease in Central America due to lower average sales prices and lower dispatch in El Salvador, partially offset by favorable hydrology in Guatemala as a result of drier weather.

Partially offsetting these decreases was:

- A $29 million increase in Ecuador due to higher dispatch as a result of drier weather.

Operating Expenses.

The decrease was driven primarily by:

- An $81 million decrease in Peru due to lower purchased power costs, thermal generation and hydrocarbon royalty costs; and
- A $55 million decrease in Central America due to lower fuel costs.

Partially offsetting these decreases was:

- A $31 million increase in Ecuador due to higher fuel consumption and the reversal of a bad debt allowance as a result of collection of an arbitration award in the prior year;
- A $24 million increase in Brazil due to transmission cost adjustments, partially offset by favorable exchange rates; and

- An $8 million increase in general and administrative expenses due to reorganization costs and higher legal costs.

Other Income and Expenses, net.

The decrease was driven primarily by a $41 million decrease in equity earnings at NMC as a result of lower pricing for both methanol and methyl tertiary butyl ether (MTBE), partially offset by lower butane costs, an approximate $18 million impairment of the investment in Attiki and approximately $14 million of decreased equity earnings at Attiki due to lower margins and the absence of prior year hedge income due to hedge contract terminations.

EBIT.

The decrease in EBIT was primarily due to lower equity earnings at NMC and Attiki, an impairment of the investment in Attiki and unfavorable exchange rates and transmission adjustments in Brazil, partially offset by favorable hydrology in Brazil and Central America and lower operating expenses in Peru.

Matters Impacting Future International Energy Results

International Energy's current strategy is focused on selectively growing its Latin American power generation business while continuing to maximize the returns and cash flow from its current portfolio. EBIT results for International Energy are sensitive to changes in hydrology, power supply, power demand, transmission and fuel constraints and fuel and commodity prices. Regulatory matters can also impact EBIT results, as well as impacts from fluctuations in exchange rates, most notably the Brazilian Real.

Certain of International Energy's long-term sales contracts and long-term debt in Brazil contain inflation adjustment clauses. While this is favorable to revenue in the long run, as International Energy's contract prices are adjusted, there is an unfavorable impact on interest expense resulting from revaluation of International Energy's outstanding local currency debt.

As noted above, International Energy is committed to selectively growing its Latin American power generation business while continuing to maximize the returns and cash flow from its current portfolio. However, International Energy periodically evaluates all of its businesses to ensure those businesses continue to align with its overall strategies. As such, International Energy is in the early stages of exploring a possible sale of certain long-lived assets in Latin America. The estimated fair value for these assets currently being evaluated for potential sale is less than carrying value. Consistent with generally accepted accounting principles (GAAP), write-downs to fair value have not been recorded on these long-lived assets as the forecasted undiscounted cash flows for the assets exceed the carrying value. In 2010, it is possible that a write-down of the carrying value of these assets to fair value could occur if a sale at an amount below carrying value becomes likely.

Year Ended December 31, 2008 as Compared to December 31, 2007

Operating Revenues.

The increase was driven primarily by:

- A $60 million increase in Brazil due to higher sales prices, higher demand and favorable exchange rates;
- A $49 million increase in Guatemala and El Salvador due to favorable sales prices partially offset by lower dispatch; and
- A $15 million increase in Argentina due to favorable sales prices as a result of higher demand.

Operating Expenses.

The increase was driven primarily by:

- A $70 million increase in Guatemala and El Salvador primarily due to higher fuel prices;
- A $57 million increase in Peru primarily due to higher purchased power, fuel costs, and royalty fees due to unfavorable hydrology and higher oil reference pricing; and
- A $15 million increase in Argentina due to higher gas and power marketing purchases and increased fuel prices.

Partially offsetting these increases was:

- A $24 million decrease in Ecuador due to lower fuel consumption and maintenance costs as a result of lower thermal dispatch and the reversal of a bad debt allowance as a result of collection of an arbitration award; and
- A $5 million decrease in Brazil due to a transmission credit adjustment and reversal of a bad debt allowance as a result of a customer settlement, partially offset by unfavorable exchange rates.

Other Income and Expenses, net.

The increase was driven primarily by a $16 million increase in equity earnings at NMC as a result of higher pricing and volumes for both methanol and MTBE and approximately $9 million of increased equity earnings at Attiki due to a hedge termination.

EBIT.

The increase in EBIT was primarily due to higher average prices, increased demand, and favorable exchange rates in Brazil, higher MTBE and methanol margins and sales volumes at NMC; partially offset by unfavorable hydrology, higher royalty fees and the lack of the 2007 transmission congestion in Peru, and unfavorable results in Guatemala, primarily due to higher fuel prices and maintenance costs.

Other

	Years Ended December 31,				
(in millions)	2009	2008	Variance 2009 vs. 2008	2007	Variance 2008 vs. 2007
Operating revenues	$ 128	$ 134	$ (6)	$ 167	$ (33)
Operating expenses	389	429	(40)	467	(38)
Gains (losses) on sales of other assets and other, net	4	3	1	2	1
Operating income	(257)	(292)	35	(298)	6
Other income and expenses, net	2	(288)	290	37	(325)
Benefit attributable to noncontrolling interest	(4)	(12)	(8)	(1)	(11)
EBIT	$(251)	$(568)	$317	$(260)	$(308)

Year Ended December 31, 2009 as Compared to December 31, 2008

Operating Income.

The increase was primarily due to favorable results at Duke Energy Trading and Marketing (DETM) and Bison Insurance Company Limited (Bison) and lower corporate costs, partially offset by higher deferred compensation expense due to improved market performance.

Other Income and Expenses, net.

The increase was due primarily to impairment charges recorded by Crescent in 2008, for which Duke Energy's proportionate share was approximately $238 million, with no comparable losses in 2009, and favorable returns on investments that support benefit obligations. Partially offsetting these favorable variances was a 2009 charge related to certain performance guarantees Duke Energy had issued on behalf of Crescent.

EBIT.

The increase was due primarily to prior year losses at Crescent, favorable results at Bison and DETM and lower corporate costs, partially offset by a 2009 charge related to certain performance guarantees Duke Energy had issued on behalf of Crescent.

Matters Impacting Future Other Results

Other's future results could be impacted by continued volatility in the debt and equity markets and other economic conditions, which could result in the recording of other-than-temporary impairment charges for investments in debt and equity securities, including certain investments in auction rate debt securities. Duke Energy analyzes all investments in debt and equity securities to determine whether a decline in fair value should be considered other-than-temporary. Criteria used to evaluate whether an impairment is other-than-temporary includes, but is not limited to, the length of time over which the market value has been lower than the cost basis of the investment, the percentage decline compared to the cost of the investment and management's intent and ability to retain its investment in the issuer for a period of time sufficient to allow for any anticipated recovery in market value. For investments in debt securities, the other-than-temporary analysis also involves the consideration of underlying collateral and guarantees of principal by government entities, as well as other factors relevant to determine the amount of credit loss, if any.

In January 2010, Duke Energy announced plans to offer a voluntary severance plan to approximately 8,750 eligible employees. As this is a voluntary plan, all severance benefits offered under this plan are considered special termination benefits under GAAP. Special termination benefits are measured upon employee acceptance and recorded immediately absent a significant retention period. If a significant retention period exists, the costs of the special termination benefits are recorded ratably over the remaining service periods of the affected employees. The window for employees to request to voluntarily end their employment under this plan opened on February 3, 2010 and closed on February 24, 2010 for approximately 8,400 eligible employees. For employees affected by the consolidation of Duke Energy's corporate functions in Charlotte, North Carolina, as discussed further below, the window will close March 31, 2010. Duke Energy currently estimates severance payments associated with this voluntary plan, based on employees' requests to voluntarily end their employment received through February 24, 2010, of approximately $130 million. However, until management of Duke Energy approves the requests, it reserves the right to reject any request to volunteer based on business needs and/or excessive participation.

In addition, in January 2010, Duke Energy announced that it will consolidate certain corporate office functions, resulting in transitioning over the next two years of approximately 350 positions from its offices in the Midwest to its corporate headquarters in Charlotte, North Carolina. Employees who do not relocate have the option to elect to participate in the voluntary plan discussed above, find a regional position within Duke Energy or remain with Duke Energy through a transition period, at which time a reduced severance benefit would be paid under Duke Energy's ongoing severance plan. Management cannot currently estimate the costs, if any, of severance benefits which will be paid to its employees due to this office consolidation.

Duke Energy believes that it is possible that the voluntary severance plan may trigger settlement accounting or curtailment accounting with respect to its pension and other post-retirement benefit plans. At this time, management is unable to determine the likelihood that settlement or curtailment accounting will be triggered.

Additionally, Duke Energy has a 50% ownership interest in Crescent, a partnership for U.S. tax purposes. Crescent filed for Chapter 11 Bankruptcy in a U.S. Bankruptcy Court in June 2009. As of December 31, 2009, Duke Energy believes it is more likely than not that all tax benefits associated with its investment in Crescent will be realized. However, the form, timing and structure of Crescent's future emergence from bankruptcy remain unresolved. Based on this uncertainty, as of December 31, 2009, it is reasonably possible that Duke Energy could incur a future tax liability related to its inability to fully utilize tax losses associated with its partnership interest in Crescent and the resolution of Crescent's emergence from bankruptcy.

Year Ended December 31, 2008 as Compared to December 31, 2007

Operating Revenues.

The reduction was driven primarily by higher premiums earned by Bison in 2007 related to the assumption of liabilities by Bison from other Duke Energy business units.

Operating Expenses.

The reduction was primarily driven by the establishment of reserves related to liabilities assumed by Bison from other Duke Energy business units in 2007 with no comparable charges in 2008, a prior year donation to the Duke Foundation, reduced benefit costs, and decreased severance costs. These favorable variances were partially offset by a prior year benefit related to contract settlement negotiations and unfavorable property loss experience at Bison.

Other Income and Expenses, net.

The increase in net expense was primarily driven by approximately $230 million of losses at Crescent in 2008 compared to earnings of approximately $38 million in 2007 due to Duke Energy recording its proportionate share of impairment charges recorded by Crescent and lower earnings as a result of the downturn in the real estate market, unfavorable returns on investments related to executive life insurance and lower investment income at Bison, partially offset by prior year convertible debt charges of approximately $21 million related to the spin-off of Spectra Energy with no comparable charges in 2008.

EBIT.

The decrease was due to Duke Energy's proportionate share of impairment charges recorded by Crescent and lower overall earnings at Crescent, a prior year benefit related to contract settlement negotiations, unfavorable investment returns and unfavorable property loss experience at Bison, partially offset by a prior year donation to Duke Foundation, prior year convertible debt charges, decreased severance costs and reduced benefits costs.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Duke Energy's operations change and accounting guidance evolves. Duke Energy has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information about Duke Energy's environment becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Duke Energy discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the audit committee, as appropriate. Duke Energy's critical accounting policies and estimates are discussed below.

Regulatory Accounting

Certain of Duke Energy's regulated operations (primarily the majority of U.S. Franchised Electric and Gas and certain portions of Commercial Power) meet the criteria for application of regulatory accounting treatment. As a result, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP in the U.S. for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that either are not likely to or have yet to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes, historical regulatory treatment for similar costs in Duke Energy's jurisdictions, recent rate orders to other regulated entities, and the status of any pending or potential deregulation legislation. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery. This assessment reflects the current political and regulatory climate at the state and federal levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs would be required to be recognized in operating income. Additionally, the regulatory agencies can provide flexibility in the manner and timing of the depreciation of property, plant and equipment, recognition of nuclear decommissioning costs and amortization of regulatory assets. Total regulatory assets were $3,886 million as of December 31, 2009 and $4,077 million as of December 31, 2008. Total regulatory liabilities were $3,108 million as of December 31, 2009 and $2,678 million as of December 31, 2008. For further information, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters."

In order to apply regulatory accounting treatment and record regulatory assets and liabilities, certain criteria must be met. In determining whether the criteria are met for its operations, management makes significant judgments, including determining whether revenue rates for services provided to customers are subject to approval by an independent, third-party regulator, whether the regulated rates are designed to recover specific costs of providing the regulated service, and a determination of whether, in view of the demand for the regulated services and the level of competition, it is reasonable to assume that rates set at levels that will recover the operations' costs can be charged to and collected from customers. This final criterion requires consideration of anticipated changes in levels of demand or competition, direct and indirect, during the recovery period for any capitalized costs. If facts and circumstances change so that a portion of Duke Energy's regulated operations meet all of the scope criteria when such criteria had not been previously met, regulatory accounting treatment would be reapplied to all or a separable portion of the operations. Such reapplication includes adjusting the balance sheet for amounts that meet the definition of a regulatory asset or regulatory liability.

Commercial Power owns, operates and manages power plants in the Midwestern United States. Commercial Power's generation asset fleet consists of Duke Energy Ohio's generation in Ohio, primarily coal-fired assets, that are dedicated to serve Ohio native load customers (native load), as well as wholesale customers to the extent there is excess generation, and five Midwestern gas-fired non-regulated generation assets that are not dedicated to serve Ohio native load customers (non-native). The non-native generation operations do not qualify for regulatory accounting treatment as these operations do not meet the scope criteria. Most of the generation asset native load output in Ohio was contracted through the RSP through December 31, 2008. As discussed further in the notes to the Consolidated Financial Statements, specifically Note 1, "Summary of Significant Accounting Policies" and Note 4, "Regulatory Matters", beginning on December 17, 2008, Commercial Power began applying regulatory accounting treatment to certain portions of its native load operations due to the passing of Ohio Senate Bill 221 (SB 221) and the approval of the ESP. However, other portions of Commercial Power's native load operations continue to not qualify for regulatory accounting treatment, as certain costs of the native load operations do not result in a rate structure designed to recover the specific costs of that portion of the operations. Despite certain portions of the Ohio native load operations not qualifying for regulatory accounting treatment, all of Commercial Power's Ohio native load operations' rates are subject to approval by the PUCO, and thus these operations are referred to here-in as Commercial Power's regulated operations. Moreover, generation remains a competitive market in Ohio and native load customers continue to have the ability to switch to alternative suppliers for their electric generation service. As customers switch, there is a risk that some or all of Commercial Power's regulatory assets will not be recovered through the established riders. Duke Energy will continue to monitor the amount of native load customers that have switched to alternative suppliers when assessing the recoverability of its regulatory assets established for its native load generation operations. At December 31, 2009, management has concluded that the established regulatory assets of approximately $163 million are still probable of recovery even though there have been increased levels of customer switching.

No other operations within Commercial Power, and no operations within the International Energy business segment, qualify for regulatory accounting treatment.

The substantial majority of U.S. Franchised Electric and Gas's operations qualify for regulatory accounting treatment and thus its costs of business and related revenues can result in the recording of regulatory assets and liabilities, as described above.

Goodwill Impairment Assessments

At December 31, 2009 and 2008, Duke Energy had goodwill balances of $4,350 million and $4,720 million, respectively. At December 31, 2009, the goodwill balances at the segment level were $3,483 million at U.S. Franchised Electric and Gas, $569 million at Commercial Power, and $298 million at International Energy. The majority of Duke Energy's goodwill relates to the acquisition of Cinergy in April 2006, whose assets are primarily included in the U.S. Franchised Electric and Gas and Commercial Power segments. Commercial Power also has approximately $70 million of goodwill that resulted from the September 2008 acquisition of Catamount, a leading wind power company located in Rutland, Vermont. As of the acquisition date, Duke Energy allocates goodwill to a reporting unit, which Duke Energy defines as an operating segment or one level below an operating segment.

Duke Energy is required to perform an annual goodwill impairment test at the reporting unit level as of the same date each year and, accordingly, performs its annual impairment testing of goodwill for all reporting units as of August 31 each year. Duke Energy updates the test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. The annual analysis of the potential impairment of goodwill requires a two step process. Step one of the impairment test involves comparing the fair values of reporting units with their aggregate carrying values, including goodwill. If the carrying amount of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of the goodwill impairment loss. If the carrying amount is less than fair value, further testing of goodwill impairment is not performed. Duke Energy did not record any impairment on its goodwill as a result of the 2008 or 2007 impairment tests.

Step two of the goodwill impairment test involves comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. Under step two, determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The difference between the fair value of the entire reporting unit as determined in step one and the net fair value of all identifiable assets and liabilities represents the implied fair value of goodwill. The goodwill impairment charge, if any, would be the difference between the carrying amount of goodwill and the implied fair value of goodwill upon the completion of step two.

For purposes of the step one analyses, determination of reporting units' fair value was based on a combination of the income approach, which estimates the fair value of Duke Energy's reporting units based on estimated discounted future cash flows, and the market approach, which estimates the fair value of Duke Energy's reporting units based on market comparables within the utility and energy industries. Based on completion of step one of the 2009 annual impairment tests, management determined that the fair values of all reporting units except for Commercial Power's non-regulated Midwest generation reporting unit, for which the carrying value of goodwill was approximately $890 million as of the annual impairment testing date, were greater than their respective carrying values. Accordingly, for only Commercial Power's non-regulated Midwest generation reporting unit, management was required to perform step two of the goodwill impairment test to determine the amount of the goodwill impairment.

Commercial Power's non-regulated Midwest generation reporting unit includes nearly 4,000 MW of coal-fired generation capacity in Ohio dedicated to serve Ohio native load customers under the ESP through December 31, 2011. These assets, as excess capacity allows, also generate revenues through sales outside the native load customer base, and such revenue is termed non-native. Additionally, this reporting unit has approximately 3,600 MW of gas-fired generation capacity in Ohio, Pennsylvania, Illinois and Indiana. The businesses within Commercial Power's non-regulated Midwest generation reporting unit operate in an unregulated environment in Ohio. As a result, the operations within this reporting unit are subjected to competitive pressures that do not exist in any of Duke Energy's regulated jurisdictions.

Commercial Power's other businesses, including the wind generation assets, are in a separate reporting unit for goodwill impairment testing purposes. No impairment exists with respect to Commercial Power's wind generation assets.

The fair value of the non-regulated Midwest generation reporting unit is impacted by a multitude of factors, including current and forecasted customer demand, current and forecasted power and commodity prices, impact of the economy on discount rates, valuation of peer companies, competition, and regulatory and legislative developments. Management's assumptions and views of these factors continually evolves, and such views and assumptions used in determining the step one fair value of the reporting unit in 2009 changed significantly from those used in the 2008 annual impairment test. These factors had a significant impact on the risk-adjusted discount rate and other inputs used to value the non-regulated Midwest generation reporting unit. These factors significantly impacted management's valuation of the reporting unit, and consequently resulted in an approximate $371 million goodwill impairment charge in 2009.

As noted above, for purposes of the step one analyses, determination of the reporting units' fair values was based on a combination of the income approach, which estimates the fair value of Duke Energy's reporting units based on discounted future cash flows, and the market approach, which estimates the fair value of Duke Energy's reporting units based on market comparables within the utility and energy industries. Key assumptions used in the income approach analyses for the U.S. Franchised Electric and Gas reporting units include, but are not limited to, the use of an appropriate discount rate, estimated future cash flows and estimated run rates of operation, maintenance, and general and administrative costs. In estimating cash flows, Duke Energy incorporates expected growth rates, regulatory stability and ability to renew contracts, as well as other factors, into its revenue and expense forecasts.

Estimated future cash flows under the income approach are based to a large extent on Duke Energy's internal business plan, and adjusted as appropriate for Duke Energy's views of market participant assumptions. In addition to the factors noted above for the Commercial Power non-regulated Midwest generation reporting unit, Duke Energy's internal business plan reflects management's assumptions related to customer usage and attrition based on internal data and economic data obtained from third party sources, as well as projected commodity pricing data. The business plan assumes the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of returns on equity, anticipated earnings/returns related to significant future capital investments, continued recovery of cost of service and the renewal of certain contracts. Management also makes assumptions regarding the run rate of operation, maintenance and general and administrative costs based on the expected outcome of the aforementioned events. Should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, revisions to current cash flow assumptions could cause the fair value of Duke Energy's reporting units to be significantly different in future periods.

One of the most significant assumptions that Duke Energy utilizes in determining the fair value of its reporting units under the income approach is the discount rate applied to the estimated future cash flows. Management determines the appropriate discount rate for each of its reporting units based on the weighted average cost of capital (WACC) for each individual reporting unit. The WACC takes into account both the cost of equity and pre-tax cost of debt. In calculating the WACCs, Duke Energy considered implied WACC's for certain peer companies in determining the appropriate WACC rates to use. As each reporting unit has a different risk profile based on the nature of its operations, including factors such as regulation, the WACC for each reporting unit may differ. Accordingly, the WACCs were adjusted, as appropriate, to account for company specific risk premiums. For example, transmission and distribution reporting units generally would have a lower company specific risk premium as they do not have the higher level of risk associated with owning and operating generation assets nor do they have significant construction risk or risk associated with potential future carbon legislation or carbon regulation. The discount rates used for calculating the fair values as of August 31, 2009 for each of Duke Energy's domestic reporting units were commensurate with the risks associated with each reporting unit and ranged from 6.0% to 9.0%. For Duke Energy's international operations, a base discount rate of 8.5% was used, with specific adders used for each separate jurisdiction in which International Energy operates to reflect the differing risk profiles of the jurisdictions and countries. This resulted in discount rates for the August 31, 2009 goodwill impairment test for the international operations ranging from approximately 9.5% to 13.5%.

Another significant assumption that Duke Energy utilizes in determining the fair value of its reporting units under the income approach is the long-term growth rate of the businesses for purposes of determining a terminal value at the end of the discrete forecast period. A long-term growth rate of three percent was used in the valuations of all of the U.S. Franchised Electric and Gas reporting units, reflecting the median long-term inflation rate and the significant capital investments forecasted for all of the U.S. Franchised Electric and Gas reporting units. A long-term growth rate of two percent was used in the valuation of the Commercial Power non-regulated Midwest generation reporting unit given the finite lives of the unregulated generation power plants and current absence of plans to reinvest in the unregulated generation assets.

These underlying assumptions and estimates are made as of a point in time; subsequent changes, particularly changes in the discount rates or growth rates inherent in management's estimates of future cash flows, could result in a future impairment charge to goodwill. Management continues to remain alert for any indicators that the fair value of a reporting unit could be below book value and will assess goodwill for impairment as appropriate.

As discussed above, with the exception of the Commercial Power non-regulated Midwest generation reporting unit, the impairment tests as of August 31, 2009 did not indicate that the fair value of any of Duke Energy's reporting units were less than its book value. For these reporting units, the estimated fair value of equity exceeded the carrying value of equity by over 15%, with the exception of U.S. Franchised Electric and Gas's Ohio T&D reporting unit. As of December 31, 2009, the Ohio T&D reporting unit had a goodwill balance of approximately $700 million. Potential circumstances that could have a negative effect on the fair value of the Ohio T&D reporting unit include additional declines in load volume forecasts, changes in the WACC, changes in the timing and/or recovery of and on investments in SmartGrid technology, and the success of future rate case filings.

As an overall test of the reasonableness of the estimated fair values of the reporting units, Duke Energy reconciled the combined fair value estimates of its reporting units to its market capitalization as of August 31, 2009. The reconciliation confirmed that the fair values were reasonably representative of market views when applying a reasonable control premium to the market capitalization. Additionally, Duke Energy would perform an interim impairment assessment should any events occur or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. Subsequent to August 31, 2009, management did not identify any indicators of potential impairment that required an update to the annual impairment test. The majority of Duke Energy's business is in environments that are either fully or partially rate-regulated. In such environments, revenue requirements are adjusted periodically by regulators based on factors including levels of costs, sales volumes and costs of capital. Accordingly, Duke Energy's regulated utilities operate to some degree with a buffer from the direct effects, positive or negative, of significant swings in market or economic conditions. Additionally, with respect to the Commercial Power non-regulated Midwest generation reporting unit, the Ohio generation assets have begun to be negatively impacted by increased competition. However, the effects of increased competition in Ohio were appropriately considered in the August 31, 2009 valuation of the reporting unit, and subsequent to August 31, 2009 management did not identify any indicators of potential impairment that required an update to the annual impairment test. However, management will continue to monitor changes in the business, as well as overall market conditions and economic factors that could require additional impairment tests.

Revenue Recognition

Revenues on sales of electricity and gas are recognized when either the service is provided or the product is delivered. Operating revenues include unbilled electric and gas revenues earned when service has been delivered but not billed by the end of the accounting period. Unbilled retail revenues are estimated by applying an average revenue per kilowatt-hour (kWh) or per Mcf for all customer classes to the number of estimated kWh or Mcfs delivered but not billed. Unbilled wholesale energy revenues are calculated by applying the contractual rate per megawatt-hour (MWh) to the number of estimated MWh delivered but not yet billed. Unbilled wholesale demand revenues are calculated by applying the contractual rate per MW to the MW volume delivered but not yet billed. The amount of unbilled revenues can vary significantly from period to period as a result of numerous factors, including seasonality, weather, customer usage patterns and customer mix. Unbilled revenues, which are primarily recorded as Receivables on the Consolidated Balance Sheets and exclude receivables sold to Cinergy Receivables Company, LLC (Cinergy Receivables), were approximately $460 million and $390 million at December 31, 2009 and 2008, respectively. Additionally, Duke Energy Ohio, Duke Energy Kentucky and Duke Energy Indiana sell, on a revolving basis, nearly all of their retail accounts receivable and a portion of their wholesale accounts receivable and related collections to Cinergy Receivables, a bankruptcy remote, special purpose entity that is a wholly-owned limited liability company of Cinergy, a wholly-owned subsidiary of Duke Energy. The securitization transaction was structured to meet the criteria for sale accounting treatment under the accounting guidance for transfers and servicing of financial assets and, accordingly, the transfers of receivables are accounted for as sales. Receivables for unbilled retail and wholesale revenues of approximately $238 million and $266 million at December 31, 2009 and 2008, respectively, were included in the sales of accounts receivables to Cinergy Receivables. Effective January 1, 2010, Duke Energy began consolidating Cinergy Receivables as a result of the adoption of new accounting rules, under which the criteria for sale accounting treatment is not met.

Accounting for Loss Contingencies

Duke Energy is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its consolidated financial statements, management makes judgments regarding the future outcome of contingent events and records a loss contingency when it is determined that it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. Management regularly reviews current information available to determine whether such accruals should be adjusted and whether new accruals are required. Estimating probable losses requires analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, state and local courts and other regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the consolidated financial statements may differ from the actual outcome once the contingency is resolved, which could have a material impact on future results of operations, financial position and cash flows of Duke Energy.

Duke Energy has experienced numerous claims for indemnification and medical cost reimbursement relating to damages for bodily injuries alleged to have arisen from the exposure to or use of asbestos in connection with construction and maintenance activities conducted by Duke Energy Carolinas on its electric generation plants prior to 1985.

Amounts recognized as asbestos-related reserves related to Duke Energy Carolinas in the Consolidated Balance Sheets totaled approximately $980 million and $1,031 million as of December 31, 2009 and 2008, respectively, and are classified in Other within Deferred Credits and Other Liabilities and Other within Current Liabilities. These reserves are based upon the minimum amount in Duke Energy's best estimate of the range of loss for current and future asbestos claims through 2027. Management believes that it is possible there will be additional claims filed against Duke Energy Carolinas after 2027. In light of the uncertainties inherent in a longer-term forecast, management does not believe that they can reasonably estimate the indemnity and medical costs that might be incurred after 2027 related to such potential claims. Asbestos-related loss estimates incorporate anticipated inflation, if applicable, and are recorded on an undiscounted basis. These reserves are based upon current estimates and are subject to greater uncertainty as the projection period lengthens. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change our estimated liability, as could any substantial adverse or favorable verdict at trial. A federal legislative solution, further state tort reform or structured settlement transactions could also change the estimated liability. Given the uncertainties associated with projecting matters into the future and numerous other factors outside our control, management believes that it is possible Duke Energy Carolinas may incur asbestos liabilities in excess of the recorded reserves.

Duke Energy has a third-party insurance policy to cover certain losses related to Duke Energy Carolinas' asbestos-related injuries and damages above an aggregate self insured retention of $476 million. Duke Energy Carolinas' cumulative payments began to exceed the self insurance retention on its insurance policy during the second quarter of 2008. Future payments up to the policy limit will be reimbursed by Duke Energy's third party insurance carrier. The insurance policy limit for potential future insurance recoveries for indemnification and medical cost claim payments is $1,051 million in excess of the self insured retention. Insurance recoveries of approximately $984 million and $1,032 million related to this policy are classified in the Consolidated Balance Sheets in Other within Investments and Other Assets and Receivables as of December 31, 2009 and 2008, respectively. Duke Energy is not aware of any uncertainties regarding the legal sufficiency of insurance claims. Management believes the insurance recovery asset is probable of recovery as the insurance carrier continues to have a strong financial strength rating.

For further information, see Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies."

Accounting for Income Taxes

Significant management judgment is required in determining Duke Energy's provision for income taxes, deferred tax assets and liabilities and the valuation recorded against Duke Energy's net deferred tax assets, if any.

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the book basis and tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the use of tax planning that could impact the ability to realize deferred tax assets. If future utilization of deferred tax assets is uncertain, a valuation allowance may be recorded against certain deferred tax assets.

In assessing the likelihood of realization of deferred tax assets, management considers estimates of the amount and character of future taxable income. Actual income taxes could vary from estimated amounts due to the impacts of various items, including changes to income tax laws, Duke Energy's forecasted financial condition and results of operations in future periods, as well as results of audits and examinations of filed tax returns by taxing authorities. Although management believes current estimates are reasonable, actual results could differ from these estimates.

Significant judgment is also required in computing Duke Energy's quarterly effective tax rate (ETR). ETR calculations are revised each quarter based on the best full year tax assumptions available at that time, including, but not limited to, income levels, deductions and credits. In accordance with interim tax reporting rules, a tax expense or benefit is recorded every quarter to adjust for the difference in tax expense computed based on the actual year-to-date ETR versus the forecasted annual ETR.

With the adoption of new income tax accounting guidance on January 1, 2007, Duke Energy began recording unrecognized tax benefits for positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, when a more-likely-than-not threshold is met for a tax position and management believes that the position will be sustained upon examination by the taxing authorities. Duke Energy records the largest amount of the unrecognized tax benefit that is greater than 50% likely of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of unrecognized tax benefits to be recorded in the Consolidated Financial Statements. Management reevaluates tax positions each period in which new information about recognition or measurement becomes available.

Undistributed foreign earnings associated with International Energy's operations are considered indefinitely reinvested, thus no U.S. tax is recorded on such earnings. This assertion is based on management's determination that the cash held in International Energy's foreign jurisdictions is not needed to fund the operations of its U.S. operations and that International Energy either has invested or has plans to reinvest such earnings. While management currently plans to indefinitely reinvest all of International Energy's unremitted earnings, should circumstances change, Duke Energy may need to record additional income tax expense in the period in which such determination changes.

For further information, see Note 6 to the Consolidated Financial Statements, "Income Taxes."

Pension and Other Post-Retirement Benefits

The calculation of pension expense, other post-retirement benefit expense and pension and other post-retirement liabilities require the use of assumptions. Changes in these assumptions can result in different expense and reported liability amounts, and future actual experience can differ from the assumptions. Duke Energy believes that the most critical assumptions for pension and other post-retirement benefits are the expected long-term rate of return on plan assets and the assumed discount rate. Additionally, medical and prescription drug cost trend rate assumptions are critical to Duke Energy's estimates of other post-retirement benefits.

Funding requirements for defined benefit (DB) plans are determined by government regulations. Duke Energy made voluntary contributions to its DB retirement plans of approximately $800 million in 2009, zero in 2008 and $350 million in 2007. Additionally, during 2007, Duke Energy contributed approximately $62 million to its other post-retirement benefit plans.

Duke Energy Plans

Duke Energy and its subsidiaries (including legacy Cinergy businesses) maintain non-contributory defined benefit retirement plans (Plans). The Plans cover most U.S. employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which may vary with age and years of service) of current eligible earnings and current interest credits. Certain legacy Cinergy employees are covered under plans that use a final average earnings formula. Under a final average earnings formula, a plan participant accumulates a retirement benefit equal to a percentage of their highest 3-year average earnings, plus a percentage of their highest 3-year average earnings in excess of covered compensation per year of participation (maximum of 35 years), plus a percentage of their highest 3-year average earnings times years of participation in excess of 35 years. Duke Energy also maintains non-qualified, non-contributory defined benefit retirement plans which cover certain executives.

Duke Energy and most of its subsidiaries also provide some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Certain employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

Duke Energy recognized pre-tax qualified pension cost of $6 million in 2009. In 2010, Duke Energy's pre-tax qualified pension cost is expected to be approximately $30 million higher than in 2009 as a result of an increase in net actuarial loss amortization in 2010, primarily attributable to the effect of negative actual returns on assets from 2008. Duke Energy recognized pre-tax nonqualified pension cost of $13 million and pre-tax other post-retirement benefits cost of $34 million, in 2009. In 2010, pre-tax non-qualified pension cost and pre-tax other post-retirement benefits costs are expected to remain approximately the same as 2009.

For both pension and other post-retirement plans, Duke Energy assumed that its plan's assets would generate a long-term rate of return of 8.5% as of December 31, 2009. The assets for Duke Energy's pension and other post-retirement plans are maintained in a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation target was set after considering the investment objective and the risk profile with respect to the trust. U.S. equities are held for their high expected return. Non-U.S. equities, debt securities, and real estate are held for diversification. Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments. Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to its targeted allocation when considered appropriate. Duke Energy also invests other post-retirement assets in the Duke Energy Corporation Employee Benefits Trust (VEBA I) and the Duke Energy Corporation Post-Retirement Medical Benefits Trust (VEBA II). The investment objective of the VEBAs is to achieve sufficient returns, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants. The VEBAs are passively managed.

The expected long-term rate of return of 8.5% for the plan's assets was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers. The weighted average returns expected by asset classes were 3.2% for U.S. equities, 2.0% for Non-U.S. equities, 1.0% for Global equities, 2.0% for fixed income securities, and 0.3% for real estate.

Duke Energy discounted its future U.S. pension and other post-retirement obligations using a rate of 5.50% as of December 31, 2009. Duke Energy determines the appropriate discount based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on a bond universe of AA and AAA-rated long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in Duke Energy's pension and post-retirement plans will impact Duke Energy's future pension expense and liabilities. Management cannot predict with certainty what these factors will be in the future. The following table presents the approximate effect on Duke Energy's 2009 pre-tax pension expense, pension obligation and other post-benefit obligation if a 0.25% change in rates were to occur:

	Qualified Pension Plans		Other Post-Retirement Plans	
(in millions)	+0.25%	-0.25%	+0.25%	-0.25%
Effect on 2009 pension expense (pre-tax)				
Expected long-term rate of return	$(11)	$11	$ (1)	$ 1
Discount rate	$ (2)	$ 2	$ (1)	$ 1
Effect on benefit obligation, at December 31, 2009 Discount rate	(99)	99	(17)	17

Duke Energy's U.S. post-retirement plan uses a medical care trend rate which reflects the near and long-term expectation of increases in medical health care costs. Duke Energy's U.S. post-retirement plan uses a prescription drug trend rate which reflects the near and long-term expectation of increases in prescription drug health care costs. As of December 31, 2009, the medical care trend rates were 8.50%, which grades to 5.00% by 2019. As of December 31, 2009, the prescription drug trend rate was 11.00%, which grades to 5.00% by 2024. The following table presents the approximate effect on Duke Energy's 2009 pre-tax other post-retirement expense and other post-benefit obligation if a 1% point change in the health care trend rate were to occur:

	Other Post-Retirement Plans	
(in millions)	+1.0%	-1.0%
Effect on other post-retirement expense	$ 3	$ (2)
Effect on post-retirement benefit obligation	38	(34)

For further information, see Note 20 to the Consolidated Financial Statements, "Employee Benefit Plans."

LIQUIDITY AND CAPITAL RESOURCES

Known Trends and Uncertainties

At December 31, 2009, Duke Energy had cash and cash equivalents of approximately $1.5 billion, of which approximately $600 million is held in foreign jurisdictions and is forecasted to be used to fund the operations of and investments in International Energy. To fund its liquidity and capital requirements during 2010, Duke Energy will rely primarily upon cash flows from operations, borrowings, equity issuances to fund the dividend reinvestment plan (DRIP) and other internal plans and its existing cash and cash equivalents. The relatively stable operating cash flows of the U.S. Franchised Electric and Gas business segment compose a substantial portion of Duke Energy's cash flows from operations and it is anticipated that it will continue to do so for the next several years. A material adverse change in operations, or in available financing, could impact Duke Energy's ability to fund its current liquidity and capital resource requirements.

Ultimate cash flows from operations are subject to a number of factors, including, but not limited to, regulatory constraints, economic trends and market volatility (see Item 1A. "Risk Factors" for details).

Duke Energy projects 2010 capital and investment expenditures of approximately $5.2 billion, primarily consisting of:

- $4.2 billion at U.S. Franchised Electric and Gas
- $0.6 billion at Commercial Power
- $0.2 billion at International Energy and
- $0.2 billion at Other

Duke Energy continues to focus on reducing risk and positioning its business for future success and will invest principally in its strongest business sectors. Based on this goal, approximately 80% of total projected 2010 capital expenditures are allocated to the U.S. Franchised Electric and Gas segment. Total U.S. Franchised Electric and Gas projected 2010 capital and investment expenditures include approximately $2.3 billion for system growth, $1.6 billion for maintenance and upgrades of existing plants and infrastructure to serve load growth, approximately $0.2 billion of nuclear fuel and approximately $0.1 billion of environmental expenditures.

With respect to the 2010 capital expenditure plan, Duke Energy has flexibility within its $5.2 billion budget to defer or eliminate certain spending should the broad economy continue to deteriorate. Of the $5.2 billion budget, approximately $2.9 billion relates to projects for which management has committed capital, including, but not limited to, the continued construction of Cliffside Unit 6 and the Edwardsport IGCC plant, and management intends to spend those capital dollars in 2010 irrespective of broader economic factors. Approximately $2.1 billion of projected 2010 capital expenditures are expected to be used primarily for overall system maintenance, customer connections and corporate expenditures. Although these expenditures are ultimately necessary to ensure overall system maintenance and reliability, the timing of the expenditures may be influenced by broad economic conditions and customer growth, thus management has more flexibility in terms of when these dollars are actually spent. The remaining planned 2010 capital expenditures of approximately $0.2 billion are of a discretionary nature and relate to growth opportunities in which Duke Energy may invest, provided there are opportunities to meet return expectations.

As a result of Duke Energy's significant commitment to modernize its generating fleet through the construction of new units, as well as its focus on increasing its renewable energy portfolio, the ability to cost effectively manage the construction phase of current and future projects is critical to ensuring full and timely recovery of costs of construction within its regulated operations. Should Duke Energy encounter significant cost overruns above amounts approved by the various state commissions, and those amounts are disallowed for recovery in rates, future cash flows and results of operations could be adversely impacted.

Duke Energy anticipates its debt to total capitalization ratio to remain at approximately 44% in 2010. In 2010, Duke Energy currently anticipates issuing additional net debt of approximately $1.7 billion at the operating subsidiary level, primarily for the purpose of funding capital expenditures. Due to the flexibility in the timing of projected 2010 capital expenditures, the timing and amount of debt issuances throughout 2010 could be influenced by changes in the timing of capital spending. Additionally, Duke Energy plans to generate approximately $400 million of cash from the issuance of common stock under its DRIP and other internal plans.

Duke Energy has access to unsecured revolving credit facilities, which are not restricted upon general market conditions, with aggregate bank commitments of approximately $3.14 billion. At December 31, 2009, Duke Energy has available borrowing capacity of approximately $1.9 billion under this facility. Management currently believes that amounts available under its revolving credit facility are accessible should there be a need to generate additional short-term financing in 2010, such as the issuance of commercial paper; however, due to the sustained downturn in overall economic conditions, specifically in the financial services sector, there is no guarantee that commitments provided by financial institutions under the revolving credit facility will be available if needed. Management expects that cash flows from operations, issuances of debt and cash generated from the issuance of common stock under the DRIP and other internal plans will be sufficient to cover the 2010 funding requirements related to capital and investments expenditures and dividend payments.

Duke Energy monitors compliance with all debt covenants and restrictions and does not currently believe it will be in violation or breach of its significant debt covenants during 2010. However, circumstances could arise that may alter that view. If and when management had a belief that such potential breach could exist, appropriate action would be taken to mitigate any such issue. Duke Energy also maintains an active dialogue with the credit rating agencies.

Operating Cash Flows

Net cash provided by operating activities was $3,463 million in 2009, compared to $3,328 million in 2008, an increase in cash provided of $135 million. The increase in cash provided by operating activities was driven primarily by:

- Excluding the impacts of non-cash impairment charges, net income increased during the year ended December 31, 2009 compared to the same period in 2008, and
- Changes in traditional working capital amounts due to timing of cash receipts and cash payments, principally a net increase in cash from taxes of approximately $740 million, partially offset by an increase in coal inventory, partially offset by
- An approximate $800 million increase in contributions to company sponsored pension plans.

Net cash provided by operating activities was $3,328 million in 2008, compared to $3,208 million in 2007, an increase in cash provided of $120 million. The increase in cash provided by operating activities was driven primarily by:

- An approximate $412 million decrease in contributions to Duke Energy's pension plan and other post retirement benefit plans, partially offset by
- Net income of $1,362 million in 2008 compared to $1,500 million in 2007.

Investing Cash Flows

Net cash used in investing activities was $4,492 million in 2009, $4,611 million in 2008, and $2,151 million in 2007.

The primary use of cash related to investing activities is capital, investment and acquisition expenditures, detailed by reportable business segment in the following table.

Capital, Investment and Acquisition Expenditures by Business Segment

	Years Ended December 31,		
	2009	2008	2007
	(in millions)		
U.S. Franchised Electric and Gas	**$3,560**	$3,650	$2,613
Commercial Power	**688**	870	442
International Energy	**128**	161	74
Other	**181**	241	153
Total consolidated	**$4,557**	$4,922	$3,282

The decrease in cash used in investing activities in 2009 as compared to 2008 is primarily due to the following:

- An approximate $365 million decrease in capital, investment and acquisition expenditures, due primarily to 2008 acquisitions discussed below.

This decrease in cash used was partially offset by the following:

- An approximate $125 million decrease in proceeds from available-for-sale securities, net of purchases, due to net purchases of approximately $25 million in 2009 compared to net proceeds of approximately $100 million in 2008,
- An approximate $70 million decrease in net emission allowance activity, reflecting net purchases in 2009 compared to net sales in 2008, and
- An approximate $30 million decrease in proceeds from asset sales.

The increase in cash used in investing activities in 2008 as compared to 2007 is primarily due to the following:

- An approximate $1,640 million increase in capital and investment expenditures, due primarily to capital expansion projects, the acquisition of Catamount (approximately $245 million) and the purchase of a portion of Saluda River Electric Cooperative (Saluda), Inc.'s ownership interest in the Catawba Nuclear Station in 2008 (approximately $150 million),
- An approximate $875 million decrease in proceeds from available-for-sale securities, net of purchases, due to net proceeds of approximately $100 million in 2008 compared to net proceeds of approximately $975 million in 2007, primarily as a result of investing excess cash obtained from the issuances of debt during 2008 versus utilizing short-term investments as a source of cash in 2007, and
- An approximate $60 million decrease in proceeds from asset sales.

These increases in cash used were partially offset by the following:

- An approximate $100 million increase in proceeds from the sale of emission allowances, net of purchases.

Financing Cash Flows and Liquidity

Duke Energy's consolidated capital structure as of December 31, 2009, including short-term debt, was 44% debt and 56% common equity. The fixed charges coverage ratio, calculated using Securities and Exchange Commission (SEC) guidelines, was 3.0 times for 2009, 3.4 times for 2008, and 3.7 times for 2007.

Net cash provided by financing activities was $1,585 million in 2009 compared to $1,591 million in 2008, a decrease in cash provided of $6 million. The change was due primarily to the following:

- An approximate $475 million decrease due to the repayment of the Duke Energy Ohio credit facility drawdown and outstanding commercial paper, and
- An approximate $80 million increase in dividends paid in 2009.

These decreases in cash provided were partially offset by:

- An approximate $385 million increase in proceeds from the issuances of common stock primarily related to the DRIP and other internal plans, and
- An approximate $210 million increase in proceeds from issuances of long-term debt, net of redemptions, as a result of net issuances of approximately $2,875 million during 2009 as compared to net issuances of approximately $2,665 million during 2008.

Net cash provided by financing activities was $1,591 million in 2008 compared to $1,327 million of cash used in 2007, an increase in cash provided of $2,918 million. The change was due primarily to the following:

- An approximate $3,090 million increase in proceeds from issuances of long-term debt, net of redemptions, as a result of net issuances of approximately $2,665 million during 2008 as compared to net repayments of approximately $425 million during 2007,
- An approximate $400 million increase due to the distribution of cash in 2007 related to the spin-off of Spectra Energy,
- An approximate $110 million increase due to payments for the redemption of convertible notes in 2007, and
- An approximate $80 million increase in proceeds from the issuances of common stock primarily related to the DRIP and other internal plans.

These increases were partially offset by:

- An approximate $690 million decrease in proceeds from issuances of notes payable and commercial paper, net of repayments, and
- An approximate $50 million increase in dividends paid in 2008.

Significant Financing Activities — Year Ended 2009.

Duke Energy issues shares of its common stock to meet certain employee benefit and long-term incentive obligations. Beginning in the fourth quarter of 2008, Duke Energy began issuing authorized but unissued shares of common stock to fulfill obligations under its DRIP and other internal plans, including 401(k) plans. Proceeds from all issuances of common stock, primarily related to the DRIP and other employee benefit plans, including employee exercises of stock options, were approximately $519 million in 2009.

During the year ended December 31, 2009, Duke Energy's total dividend per share of common stock was $0.94, which resulted in dividend payments of approximately $1,222 million.

In December 2009, Duke Energy Ohio issued $250 million principal amount of first mortgage bonds, which carry a fixed interest rate of 2.10% and mature June 15, 2013. Proceeds from this issuance, together with cash on hand, were used to repay Duke Energy Ohio's borrowing under Duke Energy's master credit facility. In conjunction with this debt issuance, Duke Energy Ohio entered into an interest rate swap agreement that converted interest on this debt issuance from the fixed coupon rate to a variable rate. The initial variable rate was set at 0.31%.

In November 2009, Duke Energy Carolinas issued $750 million principal amount of first mortgage bonds, which carry a fixed interest rate of 5.30% and mature February 15, 2040. Proceeds from this issuance will be used to fund capital expenditures and general corporate purposes, including the repayment at maturity of $500 million of senior notes and first mortgage bonds in the first half of 2010.

In October 2009, Duke Energy Indiana refunded $50 million of tax-exempt variable-rate demand bonds through the issuance of $50 million principal amount of tax-exempt term bonds, which carry a fixed interest rate of 4.95% and mature October 1, 2040. The tax-exempt bonds are secured by a series of Duke Energy Indiana's first mortgage bonds.

In September 2009, Duke Energy Ohio and Duke Energy Indiana repaid and immediately re-borrowed approximately $279 million and $123 million, respectively, under Duke Energy's master credit facility.

In September 2009, Duke Energy Carolinas converted $77 million of tax-exempt variable-rate demand bonds to tax-exempt term bonds, which carry a fixed interest rate of 3.60% and mature February 1, 2017. In connection with the conversion, the tax-exempt bonds were secured by a series of Duke Energy Carolinas' first mortgage bonds.

In September 2009, Duke Energy Kentucky issued $100 million of senior debentures, which carry a fixed interest rate of 4.65% and mature October 1, 2019. Proceeds from the issuance were used to repay Duke Energy Kentucky's borrowings under Duke Energy's master credit facility, to replenish cash used to repay $20 million principal amount of debt due September 15, 2009 and for general corporate purposes.

In August 2009, Duke Energy issued $1 billion principal amount of senior notes, of which $500 million carry a fixed interest rate of 3.95% and mature September 15, 2014 and $500 million carry a fixed interest rate of 5.05% and mature September 15, 2019. Proceeds from the issuance were used to redeem commercial paper, to fund capital expenditures in Duke Energy's unregulated businesses in the U.S. and for general corporate purposes.

In June 2009, Duke Energy Indiana refunded $55 million of tax-exempt variable-rate demand bonds through the issuance of $55 million principal amount of tax-exempt term bonds due August 1, 2039, which carry a fixed interest rate of 6.00% and are secured by a series of Duke Energy Indiana's first mortgage bonds. The refunded bonds were redeemed July 1, 2009.

In March 2009, Duke Energy Ohio issued $450 million principal amount of first mortgage bonds, which carry a fixed interest rate of 5.45% and mature April 1, 2019. Proceeds from this issuance were used to repay short-term notes and for general corporate purposes, including funding capital expenditures.

In March 2009, Duke Energy Indiana issued $450 million principal amount of first mortgage bonds, which carry a fixed interest rate of 6.45% and mature April 1, 2039. Proceeds from this issuance were used to fund capital expenditures, to replenish cash used to repay $97 million of senior notes which matured on March 15, 2009, to fund the repayment at maturity of $125 million of first mortgage bonds due July 15, 2009, and for general corporate purposes, including the repayment of short-term notes.

In January 2009, Duke Energy issued $750 million principal amount of 6.30% senior notes due February 1, 2014. Proceeds from the issuance were used to redeem commercial paper and for general corporate purposes.

In January 2009, Duke Energy Indiana refunded $271 million of tax-exempt auction rate bonds through the issuance of $271 million of tax-exempt variable-rate demand bonds, which are supported by direct-pay letters of credit, of which $144 million had initial rates of 0.7% reset on a weekly basis with $44 million maturing May 2035, $23 million maturing March 2031 and $77 million maturing December 2039. The remaining $127 million had initial rates of 0.5% reset on a daily basis with $77 million maturing December 2039 and $50 million maturing October 2040.

Significant Financing Activities — Year Ended 2008.

Duke Energy issues shares of its common stock to meet certain employee benefit and long-term incentive obligations. Beginning in the fourth quarter of 2008, Duke Energy began issuing authorized but unissued shares of common stock to fulfill obligations under its DRIP and other internal plans, including 401(k) plans. Proceeds from all issuances of common stock, primarily related to the DRIP and other employee benefit plans, including employee exercises of stock options, were approximately $133 million in 2008.

During the year ended December 31, 2008, Duke Energy's total dividend per share of common stock was $0.90, which resulted in dividend payments of approximately $1,143 million.

In December 2008, Duke Energy Kentucky refunded $50 million of tax-exempt auction rate bonds through the issuance of $50 million of tax-exempt variable-rate demand bonds, which are supported by a direct-pay letter of credit. The variable-rate demand bonds, which are due August 1, 2027, had an initial interest rate of 0.65% which is reset on a weekly basis.

In November 2008, Duke Energy Carolinas issued $900 million principal amount of first mortgage bonds, of which $500 million carry a fixed interest rate of 7.00% and mature November 15, 2018 and $400 million carry a fixed interest rate of 5.75% and mature November 15, 2013. The net proceeds from issuance were used to repay amounts borrowed under the master credit facility, to repay senior notes due January 1, 2009, to replenish cash used to repay senior notes at their scheduled maturity in October 2008 and for general corporate purposes.

In October 2008, International Energy issued approximately $153 million of debt in Brazil, of which approximately $112 million mature in September 2013 and carry a variable interest rate equal to the Brazil interbank rate plus 2.15%, and approximately $41 million mature in September 2015 and carry a fixed interest rate of 11.6% plus an annual inflation index. International Energy used these proceeds to pre-pay existing long-term debt balances.

In September 2008, Duke Energy and its wholly-owned subsidiaries, Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky, borrowed a total of approximately $1 billion under Duke Energy's master credit facility. For additional information, see "Available Credit Facilities and Restrictive Debt Covenants" below.

In August 2008, Duke Energy Indiana issued $500 million principal amount of first mortgage bonds, which carry a fixed interest rate of 6.35% and mature August 15, 2038. Proceeds from this issuance were used to fund capital expenditures and for general corporate purposes, including the repayment of short-term notes and to redeem first mortgage bonds maturing in September 2008.

In June 2008, Duke Energy issued $500 million principal amount of senior notes, of which $250 million carry a fixed interest rate of 5.65% and mature June 15, 2013 and $250 million carry a fixed interest rate of 6.25% and mature June 15, 2018. Proceeds from the issuance were used to redeem commercial paper, to fund capital expenditures in Duke Energy's unregulated businesses in the U.S. and for general corporate purposes.

In April 2008, Duke Energy Carolinas issued $900 million principal amount of first mortgage bonds, of which $300 million carry a fixed interest rate of 5.10% and mature April 15, 2018 and $600 million carry a fixed interest rate of 6.05% and mature April 15, 2038. Proceeds from the issuance were used to fund capital expenditures and for general corporate purposes. In anticipation of this debt issuance, Duke Energy Carolinas executed a series of interest rate swaps in 2007 to lock in the market interest rates at that time. The value of these interest rate swaps, which were terminated prior to issuance of the fixed rate debt, was a pre-tax loss of approximately $23 million. This amount was recorded as a component of Accumulated Other Comprehensive Loss and is being amortized as a component of Interest Expense over the life of the debt.

In April 2008, Duke Energy Carolinas refunded $100 million of tax-exempt auction rate bonds through the issuance of $100 million of tax-exempt variable-rate demand bonds, which are supported by a direct-pay letter of credit. The variable-rate demand bonds, which are due November 1, 2040, had an initial interest rate of 2.15% which will be reset on a weekly basis.

In January 2008, Duke Energy Carolinas issued $900 million principal amount of first mortgage bonds, of which $400 million carry a fixed interest rate of 5.25% and mature January 15, 2018 and $500 million carry a fixed interest rate of 6.00% and mature January 15, 2038. Proceeds from the issuance were used to fund capital expenditures and for general corporate purposes, including the repayment of commercial paper. In anticipation of this debt issuance, Duke Energy Carolinas executed a series of interest rate swaps in 2007 to lock in the market interest rates at that time. The value of these interest rate swaps, which were terminated prior to issuance of the fixed rate debt, was a pre-tax loss of approximately $18 million. This amount was recorded as a component of Accumulated Other Comprehensive Loss and is being amortized as a component of Interest Expense over the life of the debt.

Significant Financing Activities — Year Ended 2007.

Duke Energy issues shares of its common stock to meet certain employee benefit and long-term incentive obligations. Proceeds from all issuances of common stock, primarily related to employee benefit plans, including employee exercises of stock options, were approximately $50 million in 2007.

During the year ended December 31, 2007, Duke Energy's total dividend per share of common stock was $0.86, which resulted in dividend payments of approximately $1,089 million.

In December 2007, Duke Energy Ohio issued $140 million in tax-exempt floating-rate bonds. The bonds are structured as insured auction rate securities, subject to an auction process every 35 days and bear a final maturity of 2041. The initial interest rate was set at 4.85%. The bonds were issued through the Ohio Air Quality Development Authority to fund a portion of the environmental capital expenditures at the Conesville, Stuart and Killen Generation Stations in Ohio.

In November 2007, Duke Energy Carolinas issued $100 million in tax-exempt floating-rate bonds. The bonds are structured as insured auction rate securities, subject to an auction process every 35 days and bear a final maturity of 2040. The initial interest rate was set at 3.65%. The bonds were issued through the North Carolina Capital Facilities Finance Agency to fund a portion of the environmental capital expenditures at the Belews Creek and Allen Steam Stations.

In June 2007, Duke Energy Carolinas issued $500 million principal amount of 6.10% senior unsecured notes due June 1, 2037. The net proceeds from the issuance were used to redeem commercial paper that was issued to repay the outstanding $249 million 6.6% Insured Quarterly Senior Notes due 2022 on April 30, 2007, and approximately $110 million of convertible debt discussed below. The remainder was used for general corporate purposes.

On May 15, 2007, substantially all of the holders of the Duke Energy convertible senior notes required Duke Energy to repurchase the balance then outstanding at a price equal to 100% of the principal amount plus accrued interest. In May 2007, Duke Energy repurchased approximately $110 million of the convertible senior notes.

On January 2, 2007, Duke Energy completed the spin-off of the natural gas businesses. In connection with this transaction, Duke Energy distributed all the shares of Spectra Energy to Duke Energy shareholders. The distribution ratio approved by Duke Energy's Board of Directors was one-half share of Spectra Energy stock for each share of Duke Energy stock.

Available Credit Facilities and Restrictive Debt Covenants.

The total capacity under Duke Energy's master credit facility, which expires in June 2012, is approximately $3.14 billion. The credit facility contains an option allowing borrowing up to the full amount of the facility on the day of initial expiration for up to one year. Duke Energy and its wholly-owned subsidiaries, Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky (collectively referred to as the borrowers), each have borrowing capacity under the master credit facility up to specified sub limits for each borrower. However, Duke Energy has the unilateral ability to increase or decrease the borrowing sub limits of each borrower, subject to per borrower maximum cap limitations, at any time. The amount available under the master credit facility has been reduced by draw downs of cash and the use of the master credit facility to backstop the issuances of commercial paper, letters of credit and certain tax-exempt bonds.

Master Credit Facility Summary as of December 31, 2009 (in millions)[a]

	Credit Facility Capacity	Commercial Paper	Draw Down on Credit Facility	Letters of Credit	Tax-Exempt Bonds	Total Amount Utilized	Available Credit Facility Capacity
Duke Energy Corporation							
$3,137 multi-year syndicated[b][c]	$3,137	$450	$397	$121	$285	$1,253	$1,884

(a) This summary excludes certain demand facilities and committed facilities that are insignificant in size or which generally support very specific requirements, which primarily include facilities that backstop various outstanding tax-exempt bonds.
(b) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65% for each borrower.
(c) Contains sub limits at December 31, 2009 as follows: $1,097 million for Duke Energy, $840 million for Duke Energy Carolinas, $650 million for Duke Energy Ohio, $450 million for Duke Energy Indiana and $100 million for Duke Energy Kentucky.

The loans under the master credit facility are revolving credit loans that currently bear interest at one-month London Interbank Offered Rate (LIBOR) plus an applicable spread ranging from 19 to 23 basis points. The loan for Duke Energy, which was approximately $274 million at December 31, 2009, has a stated maturity of June 2012, while the loan for Duke Energy Indiana, which was approximately $123 million at December 31, 2009, had a stated maturity of September 2009; however, the borrowers have the ability under the master credit facility to renew the loans due in September 2009 on an annual basis up through the date the master credit facility matures in June 2012. As a result of these annual renewal provisions, in September 2009, Duke Energy Indiana repaid and immediately re-borrowed approximately $123 million under the master credit facility. Duke Energy and Duke Energy Indiana have the intent and ability to refinance these obligations on a long-term basis, either through renewal of the terms of the loan through the master credit facility, which has non-cancelable terms in excess of one-year, or through issuance of long-term debt to replace the amounts drawn under the master credit facility. Accordingly, total borrowings by Duke Energy and Duke Energy Indiana of approximately $397 million are reflected as Long-Term Debt on the Consolidated Balance Sheets at December 31, 2009.

In September 2008, Duke Energy Indiana and Duke Energy Kentucky collectively entered into a $330 million three-year letter of credit agreement with a syndicate of banks, under which Duke Energy Indiana and Duke Energy Kentucky may request the issuance of letters of credit up to $279 million and $51 million, respectively, on their behalf to support various series of variable rate demand bonds issued or to be issued on behalf of either Duke Energy Indiana or Duke Energy Kentucky. This credit facility, which is not part of Duke Energy's master credit facility, may not be used for any purpose other than to support the variable rate demand bonds issued by Duke Energy Indiana and Duke Energy Kentucky.

Duke Energy's debt and credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2009, Duke Energy was in compliance with all covenants related to its significant debt agreements. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

Credit Ratings.

Duke Energy and certain subsidiaries each hold credit ratings by Standard & Poor's (S&P) and Moody's Investors Service (Moody's). Duke Energy's corporate credit rating and issuer credit rating from S&P and Moody's, respectively, as of February 1, 2010 is A- and Baa2, respectively. The following table summarizes the February 1, 2010 unsecured credit ratings from the rating agencies retained by Duke Energy and its principal funding subsidiaries.

Senior Unsecured Credit Ratings Summary as of February 1, 2010

	Standard and Poor's	Moody's Investors Service
Duke Energy Corporation	BBB+	Baa2
Duke Energy Carolinas, LLC	A-	A3
Cinergy Corp.	BBB+	Baa2
Duke Energy Ohio, Inc.	A-	Baa1
Duke Energy Indiana, Inc.	A-	Baa1
Duke Energy Kentucky, Inc.	A-	Baa1

Duke Energy's credit ratings are dependent on, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures and pay dividends on its common stock, while maintaining the strength of its current balance sheet. If, as a result of market conditions or other factors, Duke Energy is unable to maintain its current balance sheet strength, or if its earnings and cash flow outlook materially deteriorates, Duke Energy's credit ratings could be negatively impacted.

Credit-Related Clauses.

Duke Energy may be required to repay certain debt should the credit ratings at Duke Energy Carolinas fall to a certain level at S&P or Moody's. As of December 31, 2009, Duke Energy had approximately $6 million of senior unsecured notes which mature serially through 2012 that may be required to be repaid if Duke Energy Carolinas' senior unsecured debt ratings fall below BBB- at S&P or Baa3 at Moody's, and $16 million of senior unsecured notes which mature serially through 2016 that may be required to be repaid if Duke Energy Carolinas' senior unsecured debt ratings fall below BBB at S&P or Baa2 at Moody's.

Other Financing Matters.

In October 2007, Duke Energy filed a registration statement (Form S-3) with the SEC. Under this Form S-3, which is uncapped, Duke Energy, Duke Energy Carolinas, Duke Energy Ohio and Duke Energy Indiana may issue debt and other securities in the future at amounts, prices and with terms to be determined at the time of future offerings. The registration statement also allows for the issuance of common stock by Duke Energy.

Duke Energy has paid quarterly cash dividends for 84 consecutive years and expects to continue its policy of paying regular cash dividends in the future. There is no assurance as to the amount of future dividends because they depend on future earnings, capital requirements, financial condition and are subject to the discretion of the Board of Directors.

Dividend and Other Funding Restrictions of Duke Energy Subsidiaries.

As discussed in Note 4 to the Consolidated Financial Statements "Regulatory Matters", Duke Energy's wholly-owned public utility operating companies have restrictions on the amount of funds that can be transferred to Duke Energy via dividend, advance or loan as a result of conditions imposed by various regulators in conjunction with Duke Energy's merger with Cinergy. Additionally, certain other Duke Energy subsidiaries have other restrictions, such as minimum working capital and tangible net worth requirements pursuant to debt and other agreements that limit the amount of funds that can be transferred to Duke Energy. At December 31, 2009, the amount of restricted net assets of wholly-owned subsidiaries of Duke Energy that may not be distributed to Duke Energy in the form of a loan or dividend is approximately $10.5 billion. However, Duke Energy does not have any legal or other restrictions on paying common stock dividends to shareholders out of its consolidated Retained Earnings account. Although these restrictions cap the amount of funding the various operating subsidiaries can provide to Duke Energy, management does not believe these restrictions will have any significant impact on Duke Energy's ability to access cash to meet its payment of dividends on common stock and other future funding obligations.

Off-Balance Sheet Arrangements

Duke Energy and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications.

Most of the guarantee arrangements entered into by Duke Energy enhance the credit standing of certain subsidiaries, non-consolidated entities or less than wholly-owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of Duke Energy, either on its own or on behalf of Spectra Energy Capital, LLC (Spectra Capital) through indemnification agreements entered into as part of the spin-off of Spectra Energy, having to honor its contingencies is largely dependent upon the future operations of the subsidiaries, investees and other third parties, or the occurrence of certain future events.

Duke Energy performs ongoing assessments of its guarantee obligations to determine whether any liabilities have been triggered as a result of potential increased non-performance risk by parties for which Duke Energy has issued guarantees. Except for certain performance obligations related to Crescent, which filed Chapter 11 bankruptcy petitions in a U.S. Bankruptcy court in June 2009 and for which a liability of approximately $26 million was recorded during 2009 due to the probability of performance under certain guarantees, it is not probable as of December 31, 2009 that Duke Energy will have to perform under its remaining existing guarantee obligations. However, management continues to monitor the financial condition of the third parties or non-wholly-owned entities for whom Duke Energy has issued guarantees on behalf of to determine whether performance under these guarantees becomes probable in the future.

See Note 17 to the Consolidated Financial Statements, "Guarantees and Indemnifications," for further details of the guarantee arrangements.

Issuance of these guarantee arrangements is not required for the majority of Duke Energy's operations. Thus, if Duke Energy discontinued issuing these guarantees, there would not be a material impact to the consolidated results of operations, cash flows or financial position.

Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky have an agreement to sell certain of their accounts receivable and related collections to Cinergy Receivables, which purchases, on a revolving basis, nearly all of the retail accounts receivable and related collections of Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky. Cinergy Receivables is not consolidated by Duke Energy since it meets the requirements to be accounted for as a qualifying special purpose entity (QSPE). Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky each retain an interest in the receivables transferred to Cinergy Receivables. The transfers of receivables are accounted for as sales under the accounting guidance for transfers and servicing of financial assets. For a more detailed discussion of the sale of certain accounts receivable, see Note 21 to the Consolidated Financial Statements, "Variable Interest Entities." With the adoption of new accounting rules related to variable interest entities (VIEs) and transfers and servicing of financial assets on January 1, 2010, Duke Energy began consolidating Cinergy Receivables as of that date.

Duke Energy also holds interests in other VIEs, both consolidated and unconsolidated. For further information, see Note 21 to the Consolidated Financial Statements, "Variable Interest Entities".

Other than the guarantee arrangements discussed above and normal operating lease arrangements, Duke Energy does not have any material off-balance sheet financing entities or structures. For additional information on these commitments, see Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies."

Contractual Obligations

Duke Energy enters into contracts that require payment of cash at certain specified periods, based on certain specified minimum quantities and prices. The following table summarizes Duke Energy's contractual cash obligations for each of the periods presented. It is expected that the majority of current liabilities on the Consolidated Balance Sheets will be paid in cash in 2010.

Contractual Obligations as of December 31, 2009

		Payments Due By Period			
(in millions)	Total	Less than 1 year (2010)	2-3 Years (2011 & 2012)	4-5 Years (2013 & 2014)	More than 5 Years (Beyond 2015)
Long-term debt[a]	$29,323	$1,778	$4,518	$4,197	$18,830
Capital leases[b]	609	37	76	64	432
Operating leases[b]	536	108	142	89	197
Purchase Obligations:[h]					
Firm capacity and transportation payments[c]	471	60	66	55	290
Energy commodity contracts[d]	9,763	2,891	3,551	1,178	2,143
Other purchase, maintenance and service obligations[e]	2,812	1,679	823	76	234
Other funding obligations[f]	480	48	96	96	240
Total contractual cash obligations[g]	$43,994	$6,601	$9,272	$5,755	$22,366

(a) See Note 15 to the Consolidated Financial Statements, "Debt and Credit Facilities." Amount includes interest payments over life of debt. Interest payments on variable rate debt instruments were calculated using interest rates derived from the interpolation of the forecast interest rate curve. In addition, a spread was placed on top of the interest rates to aid in capturing the volatility inherent in projecting future interest rates.

(b) See Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies". Amounts in the table above include the interest component of capital leases based on the interest rates explicitly stated in the lease agreements.

(c) Includes firm capacity payments that provide Duke Energy with uninterrupted firm access to electricity transmission capacity, and natural gas transportation contracts.

(d) Includes contractual obligations to purchase physical quantities of electricity, coal, nuclear fuel and limestone. Also, includes contracts that Duke Energy has designated as hedges, undesignated contracts and contracts that qualify as normal purchase/normal sale (NPNS). For contracts where the price paid is based on an index, the amount is based on forward market prices at December 31, 2009. For certain of these amounts, Duke Energy may settle on a net cash basis since Duke Energy has entered into payment netting agreements with counterparties that permit Duke Energy to offset receivables and payables with such counterparties.

(e) Includes contracts for software, telephone, data and consulting or advisory services. Amount also includes contractual obligations for engineering, procurement and construction costs for new generation plants and nuclear plant refurbishments, environmental projects on fossil facilities, major maintenance of certain non-regulated plants, maintenance and day to day contract work at certain wind facilities and commitments to buy wind and combustion turbines (CT). Amount excludes certain open purchase orders for services that are provided on demand, for which the timing of the purchase cannot be determined.

(f) Relates to future annual funding obligations to the nuclear decommissioning trust fund (NDTF) (see Note 7 to the Consolidated Financial Statements, "Asset Retirement Obligations").

(g) The table above excludes certain obligations discussed herein related to amounts recorded within Deferred Credits and Other Liabilities on the Consolidated Balance Sheets due to the uncertainty of the timing and amount of future cash flows necessary to settle these obligations. The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Duke Energy may use internal resources or external resources to perform retirement activities. As a result, cash obligations for asset retirement activities are excluded from the table above. However, the vast majority of asset retirement obligations will be settled beyond 2014. Asset retirement obligations recognized on the Consolidated Balance Sheets total $3,185 million and the fair value of the NDTF, which will be used to help fund these obligations, is $1,765 million at December 31, 2009. The table above excludes reserves for litigation, environmental remediation, asbestos-related injuries and damages claims and self-insurance claims (see Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies") because Duke Energy is uncertain as to the timing of when cash payments will be required. Additionally, the table above excludes annual insurance premiums that are necessary to operate the business, including nuclear insurance (see Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies"), funding of pension and other post-retirement benefit plans (see Note 20 to the Consolidated Financial Statements, "Employee Benefit Plans") and regulatory liabilities (see Note 4 to the Consolidated Financial Statements, "Regulatory Matters") because the amount and timing of the cash payments are uncertain. Also excluded are Deferred Income Taxes and Investment Tax Credits recorded on the Consolidated Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year. Additionally, amounts related to uncertain tax positions are excluded from the table above due to uncertainty of timing of future payments.

(h) Current liabilities, except for current maturities of long-term debt, and purchase obligations reflected in the Consolidated Balance Sheets, have been excluded from the above table.

Quantitative and Qualitative Disclosures About Market Risk

Risk Management Policies

Duke Energy is exposed to market risks associated with commodity prices, credit exposure, interest rates, equity prices and foreign currency exchange rates. Management has established comprehensive risk management policies to monitor and manage these market risks. Duke Energy's Chief Executive Officer and Chief Financial Officer are responsible for the overall approval of market risk management policies and the delegation of approval and authorization levels. The Finance and Risk Management Committee of the Board of Directors receives periodic updates from the Chief Risk Officer and other members of management on market risk positions, corporate exposures, credit exposures and overall risk management activities. The Chief Risk Officer is responsible for the overall governance of managing credit risk and commodity price risk, including monitoring exposure limits.

Commodity Price Risk

Duke Energy is exposed to the impact of market fluctuations in the prices of electricity, coal, natural gas and other energy-related products marketed and purchased as a result of its ownership of energy related assets. Duke Energy's exposure to these fluctuations is limited by the cost-based regulation of its U.S. Franchised Electric and Gas operations and certain portions of Commercial Power's operations as these regulated operations are typically allowed to recover certain of these costs through various cost-recovery clauses, including the fuel clause. While there may be a delay in timing between when these costs are incurred and when these costs are recovered through rates, changes from year to year have no material impact on operating results of these regulated operations. Additionally, most of Duke Energy's long-term power sales contracts substantially shift all fuel price risk to the purchaser.

Price risk represents the potential risk of loss from adverse changes in the market price of electricity or other energy commodities. Duke Energy's exposure to commodity price risk is influenced by a number of factors, including contract size, length, market liquidity, location and unique or specific contract terms. Duke Energy employs established policies and procedures to manage its risks associated with these market fluctuations, which may include using various commodity derivatives, such as swaps, futures, forwards and options. For additional information, see Note 8 to the Consolidated Financial Statements, "Risk Management, Derivative Instruments and Hedging Activities."

Validation of a contract's fair value is performed by an internal group separate from Duke Energy's deal origination areas. While Duke Energy uses common industry practices to develop its valuation techniques, changes in Duke Energy's pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition.

Hedging Strategies.

Duke Energy closely monitors the risks associated with commodity price changes on its future operations and, where appropriate, uses various commodity instruments such as electricity, coal and natural gas forward contracts to mitigate the effect of such fluctuations on operations. Duke Energy's primary use of energy commodity derivatives is to hedge the generation portfolio against exposure to the prices of power and fuel.

Certain derivatives used to manage Duke Energy's commodity price exposure are accounted for as either cash flow hedges or fair value hedges. To the extent that instruments accounted for as hedges are effective in offsetting the transaction being hedged, there is no impact to the Consolidated Statements of Operations until after delivery or settlement occurs. Accordingly, assumptions and valuation techniques for these contracts have no impact on reported earnings prior to settlement. Several factors influence the effectiveness of a hedge contract, including the use of contracts with different commodities or unmatched terms and counterparty credit risk. Hedge effectiveness is monitored regularly and measured at least quarterly.

In addition to the hedge contracts described above and recorded on the Consolidated Balance Sheets, Duke Energy enters into other contracts that qualify for the NPNS exception. When a contract meets the criteria to qualify as a NPNS, U.S. Franchised Electric and Gas and Commercial Power apply such exception. Income recognition and realization related to normal purchases and normal sales contracts generally coincide with the physical delivery of power. For contracts qualifying for the NPNS exception, no recognition of the contract's fair value in the Consolidated Financial Statements is required until settlement of the contract as long as the transaction remains probable of occurring.

Other derivatives used to manage Duke Energy's commodity price exposure are either not designated as a hedge or do not qualify for hedge accounting. These instruments are referred to as undesignated contracts. Undesignated derivatives entered into by regulated businesses reflect mark-to-market changes of the derivative instruments fair value as a regulatory asset or liability on the Consolidated Balance Sheets. Undesignated derivatives entered into by unregulated businesses are marked-to-market each period, with changes in the fair value of the derivative instruments reflected in earnings.

Generation Portfolio Risks for 2010.

Duke Energy is primarily exposed to market price fluctuations of wholesale power, natural gas, and coal prices in the U.S. Franchised Electric and Gas and Commercial Power segments. Duke Energy optimizes the value of its bulk power marketing and non-regulated generation portfolios. The portfolios include generation assets (power and capacity), fuel, and emission allowances. The component pieces of the portfolio are bought and sold based on models and forecasts of generation in order to manage the economic value of the portfolio in accordance with the strategies of the business units. The generation portfolio not utilized to serve native load or committed load is subject to commodity price fluctuations, although the impact on the Consolidated Statements of Operations reported earnings is partially offset by mechanisms in the regulated jurisdictions that result in the sharing of net profits from these activities with retail customers. Based on a sensitivity analysis as of December 31, 2009 and 2008, it was estimated that a 10% price change per MWh in forward wholesale power prices would have a corresponding effect on Duke Energy's pre-tax income of approximately $12 million in 2010 and would have had a $10 million impact in 2009, excluding the impact of mark-to-market changes on non-qualifying or undesignated hedges relating to periods in excess of one year from the respective date, which are discussed further below. Based on a sensitivity analysis as of December 31, 2009 and 2008, it was estimated that a 10% change in the forward price per ton of coal would have a corresponding effect on Duke Energy's pre-tax income of approximately $8 million in 2010 and would have had a $10 million impact in 2009, excluding the impact of mark-to-market changes on non-qualifying or undesignated hedges relating to periods in excess of one year from the respective date. Based on a sensitivity analysis as of December 31, 2009 and 2008, it was estimated that a 10% price change per Million British Thermal Unit (MMBtu) in natural gas prices would have a corresponding effect on Duke Energy's pre-tax income of approximately $6 million in 2010 and would have had a $5 million impact in 2009, excluding the impact of mark-to-market changes on undesignated hedges relating to periods in excess of one year from the respective date, which are discussed further below.

Sensitivities for derivatives beyond 2010.

Derivative contracts executed to manage generation portfolio risks for delivery periods beyond 2010 are also exposed to changes in fair value due to market price fluctuations of wholesale power and coal. Based on a sensitivity analysis as of December 31, 2009 and 2008, it was estimated that a 10% price change in the forward price per MWh of wholesale power would have a corresponding effect on Duke Energy's pre-tax income of approximately $24 million in 2010 and would have had a $11 million impact in 2009, resulting from the impact of mark-to-market changes on non-qualifying and undesignated power contracts pertaining to periods in excess of one year from the respective date. Based on a sensitivity analysis as of December 31, 2009 and 2008, it was estimated that a 10% change in the forward price per ton of coal would have a corresponding effect on Duke Energy's pre-tax income of approximately $10 million in 2010 and 2009, resulting from the impact of mark-to-market changes on non-qualifying and undesignated coal contracts pertaining to periods in excess of one year from the respective date.

Other Commodity Risks.

At December 31, 2009 and 2008, pre-tax income in 2010 and 2009 was not expected to be materially impacted for exposures to other commodities' price changes.

The commodity price sensitivity calculations above consider existing hedge positions and estimated production levels, but do not consider other potential effects that might result from such changes in commodity prices.

Credit Risk

Credit risk represents the loss that Duke Energy would incur if a counterparty fails to perform under its contractual obligations. To reduce credit exposure, Duke Energy seeks to enter into netting agreements with counterparties that permit Duke Energy to offset receivables and payables with such counterparties. Duke Energy attempts to further reduce credit risk with certain counterparties by entering into agreements that enable Duke Energy to obtain collateral or to terminate or reset the terms of transactions after specified time periods or upon the occurrence of credit-related events. Duke Energy may, at times, use credit derivatives or other structures and techniques to provide for third-party credit enhancement of Duke Energy's counterparties' obligations. Duke Energy also obtains cash or letters of credit from customers to provide credit support outside of collateral agreements, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

Duke Energy's industry has historically operated under negotiated credit lines for physical delivery contracts. Duke Energy frequently uses master collateral agreements to mitigate certain credit exposures. The collateral agreements provide for a counterparty to post cash or letters of credit to the exposed party for exposure in excess of an established threshold. The threshold amount represents an unsecured credit limit, determined in accordance with the corporate credit policy. Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions.

Duke Energy's principal customers for power and natural gas marketing and transportation services are industrial end-users, marketers, local distribution companies and utilities located throughout the U.S. and Latin America. Duke Energy has concentrations of receivables from natural gas and electric utilities and their affiliates, as well as industrial customers and marketers throughout these regions. These concentrations of customers may affect Duke Energy's overall credit risk in that risk factors can negatively impact the credit quality of the entire sector. Where exposed to credit risk, Duke Energy analyzes the counterparties' financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of those limits on an ongoing basis.

Duke Energy has a third-party insurance policy to cover certain losses related to Duke Energy Carolinas' asbestos-related injuries and damages above an aggregate self insured retention of $476 million. Duke Energy Carolinas' cumulative payments began to exceed the self insurance retention on its insurance policy during the second quarter of 2008. Future payments up to the policy limit will be reimbursed by Duke Energy's third party insurance carrier. The insurance policy limit for potential future insurance recoveries for indemnification and medical cost claim payments is $1,051 million in excess of the self insured retention. Insurance recoveries of approximately $984 million and $1,032 million related to this policy are classified in the Consolidated Balance Sheets in Other within Investments and Other Assets and Receivables as of December 31, 2009 and 2008, respectively. Duke Energy is not aware of any uncertainties regarding the legal sufficiency of insurance claims. Management believes the insurance recovery asset is probable of recovery as the insurance carrier continues to have a strong financial strength rating.

Duke Energy and its subsidiaries also have credit risk exposure through issuance of performance guarantees, letters of credit and surety bonds on behalf of less than wholly-owned entities and third parties. Where Duke Energy has issued these guarantees, it is possible that Duke Energy could be required to perform under these guarantee obligations in the event the obligor under the guarantee fails to perform. Where Duke Energy has issued guarantees related to assets or operations that have been disposed of via sale, Duke Energy attempts to secure indemnification from the buyer against all future performance obligations under the guarantees. See Note 17 to the Consolidated Financial Statements, "Guarantees and Indemnifications," for further information on guarantees issued by Duke Energy or its subsidiaries.

Duke Energy is also subject to credit risk of its vendors and suppliers in the form of performance risk on contracts including, but not limited to, outsourcing arrangements, major construction projects and commodity purchases. Duke Energy's credit exposure to such vendors and suppliers may take the form of increased costs or project delays in the event of non-performance.

Based on Duke Energy's policies for managing credit risk, its exposures and its credit and other reserves, Duke Energy does not anticipate a materially adverse effect on its consolidated financial position or results of operations as a result of non-performance by any counterparty.

Interest Rate Risk

Duke Energy is exposed to risk resulting from changes in interest rates as a result of its issuance of variable and fixed rate debt and commercial paper. Duke Energy manages its interest rate exposure by limiting its variable-rate exposures to a percentage of total capitalization and by monitoring the effects of market changes in interest rates. Duke Energy also enters into financial derivative instruments, which may include instruments such as, but not limited to, interest rate swaps, swaptions and U.S. Treasury lock agreements to manage and mitigate interest rate risk exposure. See Notes 1, 8, 9, and 15 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies," "Risk Management, Derivative Instruments and Hedging Activities," "Fair Value of Financial Assets and Liabilities," and "Debt and Credit Facilities."

Based on a sensitivity analysis as of December 31, 2009, it was estimated that if market interest rates average 1% higher (lower) in 2010 than in 2009, interest expense, net of offsetting impacts in interest income, would increase (decrease) by approximately $19 million. Comparatively, based on a sensitivity analysis as of December 31, 2008, had interest rates averaged 1% higher (lower) in 2009 than in 2008, it was estimated that interest expense, net of offsetting impacts in interest income, would have increased (decreased) by approximately $28 million. These amounts were estimated by considering the impact of the hypothetical interest rates on variable-rate securities outstanding, adjusted for interest rate hedges, short-term and long-term investments, cash and cash equivalents outstanding as of December 31, 2009 and 2008. The decrease in interest rate sensitivity is primarily due to a decrease in tax-exempt bonds and commercial paper, partial repayment of the master credit facility borrowings, and increased cash balances. If interest rates changed significantly, management would likely take actions to manage its exposure to the change. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no changes in Duke Energy's financial structure.

Marketable Securities Price Risk

As described further in Note 10 to the Consolidated Financial Statements, "Investments in Debt and Equity Securities," Duke Energy invests in debt and equity securities as part of various investment portfolios to fund certain obligations of the business. The vast majority of the investments in equity securities are within the NDTF and assets of the various pension and other post-retirement benefit plans.

NDTF.

As discussed further in Note 7 to the Consolidated Financial Statements, "Asset Retirement Obligations", Duke Energy maintains trust funds to fund the costs of nuclear decommissioning. As of December 31, 2009, these funds were invested primarily in domestic and international equity securities, debt securities, fixed-income securities, cash and cash equivalents and short-term investments. Per NRC and NCUC requirements, these funds may be used only for activities related to nuclear decommissioning. The investments are exposed to price fluctuations in debt and equity markets. Accounting for nuclear decommissioning recognizes that costs are recovered through U.S. Franchised Electric and Gas' rates; therefore, fluctuations in equity prices do not affect Duke Energy's Consolidated Statements of Operations as changes in the fair value of these investments are deferred as regulatory assets or regulatory liabilities. Earnings or losses of the fund will ultimately impact the amount of costs recovered through U.S. Franchised Electric and Gas' rates over time. Management monitors the NDTF investment portfolio by benchmarking the performance of the investments against certain indices and by maintaining and periodically reviewing target allocation percentages for various asset classes.

The following table provides the fair value of investments held in the NDTF at December 31, 2009:

(in millions)	Fair Value at December 31, 2009
Equity Securities	$1,156
Corporate Debt Securities	195
U.S. Government Bonds	258
Municipal Bonds	56
Other	100
Total	$1,765

Pension Plan Assets.

Duke Energy maintains investments to help fund the costs of providing non-contributory defined benefit retirement and other post-retirement benefit plans. Those investments are exposed to price fluctuations in equity markets and changes in interest rates. Duke Energy has established asset allocation targets for its pension plan holdings, which take into consideration the investment objectives and the risk profile with respect to the trust in which the assets are held. Duke Energy's target asset allocation for equity securities is approximately 64% of the value of the plan assets and the holdings are diversified to achieve broad market participation and reduce the impact of any single investment, sector or geographic region. A significant decline in the value of plan asset holdings could require Duke Energy to increase its funding of the pension plan in future periods, which could adversely affect cash flows in those periods. Additionally, a decline in the fair value of plan assets, absent additional cash contributions to the plan, could increase the amount of pension cost required to be recorded in future periods, which could adversely affect Duke Energy's results of operations in those periods. During 2009, Duke Energy contributed approximately $800 million to its qualified pension plan. See Note 20 to the Consolidated Financial Statements, "Employee Benefit Plans," for additional information on pension plan assets.

Foreign Currency Risk

Duke Energy is exposed to foreign currency risk from investments in international affiliate businesses owned and operated in foreign countries and from certain commodity-related transactions within domestic operations that are denominated in foreign currencies. To mitigate risks associated with foreign currency fluctuations, contracts may be denominated in or indexed to the U.S. Dollar and/or local inflation rates, or investments may be naturally hedged through debt denominated or issued in the foreign currency. Duke Energy may also use foreign currency derivatives, where possible, to manage its risk related to foreign currency fluctuations. To monitor its currency exchange rate risks, Duke Energy uses sensitivity analysis, which measures the impact of devaluation of the foreign currencies to which it has exposure.

In 2010, Duke Energy's primary foreign currency rate exposure is to the Brazilian Real. A 10% devaluation in the currency exchange rates as of December 31, 2009 in all of Duke Energy's exposure currencies would result in an estimated net pre-tax loss on the translation of local currency earnings of approximately $20 million to Duke Energy's Consolidated Statements of Operations in 2010. The Consolidated Balance Sheet would be negatively impacted by approximately $160 million currency translation through the cumulative translation adjustment in AOCI as of December 31, 2009 as a result of a 10% devaluation in the currency exchange rates. For comparative purposes, as of December 31, 2008, a 10% devaluation in the currency exchange rates in all of Duke Energy's exposure currencies was expected to result in an estimated net pre-tax loss on the translation of local currency earnings of approximately $10 million to Duke Energy's Consolidated Statements of Operations and a reduction of approximately $120 million currency translation through the cumulative translation adjustment in AOCI as of December 31, 2008.

Other Issues

Global Climate Change.

Although there is still much to learn about the causes and long-term effects of climate change, many, including Duke Energy, advocate taking steps now to begin reducing greenhouse gas (GHG) emissions with the long-term aim of stabilizing the atmospheric concentration of GHGs at a level that avoids any potentially worst-case effects of climate change.

The EPA publishes an inventory of man-made U.S. GHG emissions annually. Carbon dioxide (CO_2), a byproduct of fossil fuel combustion, currently accounts for about 85% of total U.S. GHG emissions. Duke Energy's GHG emissions consist primarily of CO_2 and most come from its fleet of coal fired power plants in the U.S. In 2009, Duke Energy's U.S. power plants emitted approximately 91 million tons of CO_2. The CO_2 emissions from Duke Energy's international electric operations are less than 3 million tons annually. Duke Energy's future CO_2 emissions will be influenced by variables including new regulations, economic conditions that affect electricity demand, and Duke Energy's decisions regarding generation technologies deployed to meet customer electricity needs.

Congress has not yet passed legislation mandating control or reduction of GHGs. On June 26, 2009, the U. S. House of Representatives passed H.R. 2454 - the American Clean Energy and Security Act of 2009 (ACES). This legislation includes a GHG cap-and-trade program that covers approximately 85% of the GHG emissions in the U.S. economy, including emissions from the electric utility sector. The legislation also includes a combined efficiency and renewable electricity standard that applies to the electric utility sector. The standard establishes minimum requirements for the amount of renewable energy electric utilities must provide to end-use customers on an annual basis. It allows companies to comply by providing renewable energy, buying renewable energy credits from other companies or the government, or by reducing customer electricity demand through the deployment of energy efficiency programs.

On November 5, 2009, the U.S. Senate Environment and Public Works Committee passed and sent to the Senate floor S. 1733 — the Clean Energy Jobs and American Power Act of 2009 (S. 1733). The legislation included an economy-wide cap-and-trade program similar to the one contained in ACES. The Senate Energy and Natural Resources Committee had previously passed legislation containing new requirements for energy efficiency and for a renewable electricity standard. No further Senate action has been taken on either bill since passage out of their respective committees.

The debates that took place in the U.S. Senate in 2008 and 2009 make it clear that there are wide-ranging views among Senators regarding what constitutes acceptable climate change legislation. These divergent views, the state of the economy, the current structure of the Senate necessitating 60 votes to move legislation and the political pressures as the 2010 mid-term election approaches, make passage of federal climate change legislation in the Senate in 2010 highly uncertain. If the Senate were to pass some type of climate change legislation in 2010, the Senate legislation would need to be reconciled with ACES. This adds another layer of uncertainty to the prospects for enactment of climate change legislation in 2010.

On December 7, 2009, the EPA finalized an Endangerment Finding for greenhouse gases under the CAA. The Endangerment Finding does not impose any regulatory requirements on industry, but is a necessary prerequisite for the EPA to be able to finalize its proposed GHG emission standard for new motor vehicles. It is expected that the EPA will finalize its New Motor Vehicle Rule by the end of March 2010. Implementation of the New Motor Vehicle Rule may trigger permitting requirements and potentially GHG emission control requirements for new and existing "major" stationary sources of GHG emissions which would include all of Duke Energy's fossil fuel facilities. The EPA has stated that permitting requirements for GHGs will not apply to stationary sources in 2010.

The EPA has also proposed the Tailoring Rule, which is expected to be finalized by the end of March 2010. This rule is intended to provide relief from the EPA's GHG regulations for certain types of stationary sources, but not electric generating facilities. There is, at present, considerable uncertainty over the timing and the specific requirements that would apply to any stationary source that might potentially be subject to GHG permitting and emission reduction requirements as a result of the EPA's rules. Although Duke Energy does not anticipate taking actions that would trigger the GHG permitting requirements or GHG emission reduction requirements at any of its existing generating facilities, if it were to do so, the current uncertainty surrounding the implementation of the rules and the requirements that might apply prevent management from being able to determine at this time whether the EPA rules will have a material impact on Duke Energy's future results of operations. Numerous groups have already filed petitions with the D.C. Circuit Court of Appeals for review of the EPA's Endangerment Finding. It is likely that the EPA's upcoming New Motor Vehicle and Tailoring rules will also be challenged in court once they are finalized. The current and expected legal challenges create additional uncertainty with respect to the EPA rules and what regulatory requirements, if any, will result from the rules.

Duke Energy supports the enactment of workable federal GHG legislation. Duke Energy prefers federal legislation over any EPA regulation of GHG emissions under the current CAA and believes that any legislation must include provisions that block the EPA from doing so and provide that the legislative program is the sole remedy for a source's GHG emissions. To permit the economy to adjust rationally to the policy, legislation should establish a long-term program that first slows the growth of emissions, stops them and then transitions to a gradually declining emissions cap as new lower-and zero-emitting technologies are developed and become available for wide-scale deployment at a reasonable cost. Federal legislation should also include effective cost-containment measures to protect the U.S. economy from harmful consequences if compliance costs are excessive.

Duke Energy is unable to determine the potential cost of complying with unspecified and unknowable future GHG legislation or any indirect costs that might result, however, such costs could be significant. Duke Energy's cost of complying with any legislatively-mandated federal GHG emissions regulations will depend upon the design details of the program, and upon the future levels of Duke Energy's GHG emissions that might be regulated under the program. If potential future federal GHG legislation mandates a cap-and-trade approach, for example, the design elements of such a program that will have the greatest influence on Duke Energy's compliance costs include (i) the level of the emissions cap over time, (ii) the GHG emission sources covered under the cap, (iii) the number of allowances that Duke Energy might be allocated at no cost on a year-to-year basis, (iv) the type and effectiveness of any cost containment measures that may be included in the program, (v) the role of emission offsets in the program, (vi) the availability and cost of technologies that will be available for Duke Energy to deploy to lower its emissions over time, and (vii) the price of allowances and emission offsets. Although Duke Energy believes it is likely that Congress will adopt mandatory GHG emission reduction legislation at some point, the timing and design details of any such legislation are highly uncertain at this time.

Assuming that a federal GHG cap-and-trade program is eventually enacted, Duke Energy's compliance obligation under such a program would generally be determined by the difference between the level of its emissions in a given year and the number of no-cost allowances it receives for that year. This difference would represent the emission reductions that Duke Energy would need to achieve to comply and/or the number of allowances and/or offsets Duke Energy would need to purchase to comply, or a combination of the two. The cost of achieving the emission reductions and/or the cost of purchasing the needed allowances and/or emission offsets would represent Duke Energy's compliance costs. This is why the more no-cost allowances Duke Energy receives, the lower its compliance obligation will be, and the lower its compliance cost will be. This is also why actions Duke Energy is taking today to reduce its GHG emissions over time will lower its exposure to any future GHG regulation. Under any future scenario involving mandatory GHG limitations, Duke Energy would plan to seek to recover its compliance costs through appropriate regulatory mechanisms in the jurisdictions in which it operates.

Although a near-term compliance strategy under a GHG cap-and-trade program might be focused primarily on the purchase of allowances and/or offsets due to the lack of available emission reduction technologies and/or the time it would take to deploy technologies once they become available, it is likely that over time there would be more focus placed on deploying technology to achieve large-scale reductions in emissions. This strategy could involve replacing some existing coal-fired generation with new lower-and zero-emitting generation technologies, and/or installing new carbon capture and sequestration technology when the technologies become ready for deployment. Although there is uncertainty about what new technologies may be developed, when they may be deployed, and what their costs will be, Duke Energy currently is focused on advanced nuclear generation, IGCC with CO_2 capture and sequestration, and CO_2 capture and storage retrofit technology for existing pulverized coal-fired generation as promising technologies for generating electricity with lower or no CO_2 emissions. Duke Energy is also making a significant commitment to increased customer energy efficiency and promoting enhanced use of renewable energy for meeting customers' electricity needs. Duke Energy's actions are designed to build a sustainable business that allows our customers and our shareholders to prosper in what is expected to be a carbon-constrained environment.

At the state level, the Midwestern Governors Association launched an initiative several years ago called the Midwestern Greenhouse Gas Reduction Accord (Accord). One of the objectives of the initiative was to produce a Model Rule for implementing a GHG cap-and-trade system on a regional level for consideration by individual states. In October 2009, the Accord produced a draft

Model Rule, and plans to finalize the document in early 2010. Once finalized, the Model Rule will be available to states for their consideration and possible adoption and implementation. The states of Ohio and Indiana, where Duke Energy has electric generation operations, have been observers to the Accord process and have shown no interest in adopting the Model Rule. Based on the current position of Indiana and Ohio in this regard, Duke Energy does not anticipate any cost impacts from the initiative.

In December 2007, Duke Energy began the regulatory process to construct a new nuclear power plant, William States Lee III Nuclear Station, in South Carolina, by petitioning the NRC for a COL. If constructed, this facility would produce virtually no GHGs.

With regard to advanced clean-coal, Duke Energy is in the process of constructing an IGCC power plant in Indiana. One of the key features of the IGCC technology is that it has the potential to support the capture of its CO_2 emissions, with subsequent underground storage of the captured CO_2. Although the IGCC plant, scheduled to begin operations in 2012, is not currently being equipped with the technology to capture CO_2, space was included in the design of the plant for this technology to be added later. Duke Energy is working to complete in early 2011 the front-end engineering and design of a CO_2-capture facility. The deployment of CO_2 capture and storage technology would help Duke Energy comply with any future GHG emission reduction requirements.

The state legislatures of North Carolina and Ohio have passed laws that require Duke Energy to meet increasing percentages of its customers' electricity needs with renewable energy and customer energy efficiency. In North Carolina the requirement reaches 12.5% in 2021 and in Ohio it reaches a minimum of 12.5% in 2024. Duke Energy will be meeting these requirements through a variety of actions and each is expected to assist Duke Energy's overall effort to reduce its CO_2 emissions. Versions of an energy efficiency and renewable electricity standard have been passed by the House as part of ACES and by the Senate Energy and Natural Resources Committee in S. 1462. Given the current challenges associated with passing comprehensive federal climate change legislation, Congress could instead attempt to pass energy legislation in 2010 that includes a federal energy efficiency and renewable electricity standard — provisions both the full House and a Senate committee have approved, albeit at different levels. If this were to occur, Duke Energy's compliance with the North Carolina and Ohio requirements would further its ability to comply with whatever federal requirements Congress might enact.

In addition to relying on new technologies to reduce its CO_2 emissions, Duke Energy has filed for regulatory approval in most of the states in which it operates for its energy efficiency programs, which will help meet customer electricity needs by increasing energy efficiency, thereby reducing demand instead of relying almost exclusively on new power plants to generate electricity. Duke Energy has received regulatory approval from Ohio, North Carolina and South Carolina and is in the process of rolling programs out in these states. Duke Energy received regulatory approval from Indiana and has withdrawn its filing in Kentucky.

Duke Energy recognizes that certain groups associate frequent and severe extreme weather events with climate change and the associated damage to the electric distribution system and the possibility that these weather events could have a material impact on future results of operations should these events occur. However, the uncertain nature of potential changes in extreme weather events (such as increased frequency, duration, and severity), the long period of time over which any changes might take place, and the inability to predict these accurately, make estimating any potential future financial risk to Duke Energy's operations that may be caused by the physical risks of climate change impossible. Currently, Duke Energy plans and prepares for extreme weather events that it experiences from time to time, such as ice storms, tornados, severe thunderstorms, high winds and droughts. Duke Energy's past experiences preparing for and responding to the impacts of these types of weather-related events would reasonably be expected to help management plan and prepare for future climate change-related severe weather events to reduce, but not eliminate, the operational, economic and financial impacts of such events. Duke Energy also routinely takes steps to reduce the potential impact of severe weather events on its electric distribution systems. Duke Energy does not currently operate in coastal areas and therefore is not exposed to the effects of potential sea level rise. Duke Energy's electric generating facilities are designed to withstand extreme weather events without damage. Duke Energy maintains an inventory of coal and oil on site to mitigate the effects of any potential short-term disruption in its fuel supply so it can continue to provide its customers with an uninterrupted supply of electricity.

For additional information on other issues related to Duke Energy, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters" and Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies."

New Accounting Standards

The following new Accounting Standard Updates (ASU) have been issued, but have not yet been adopted by Duke Energy, as of December 31, 2009:

Accounting Standards Codification (ASC) 860 — Transfers and Servicing. In June 2009, the Financial Accounting Standards Board (FASB) issued revised accounting guidance for transfers and servicing of financial assets and extinguishment of liabilities, to require additional information about transfers of financial assets, including securitization transactions, as well as additional information about an enterprise's continuing exposure to the risks related to transferred financial assets. This revised accounting guidance eliminates the concept of a QSPE and requires those entities which were not subject to consolidation under previous accounting rules to now be assessed for consolidation. In addition, this accounting guidance clarifies and amends the derecognition criteria for transfers of financial assets (including transfers of portions of financial assets) and requires additional disclosures about a transferor's continuing involvement in transferred financial assets. For Duke Energy, this revised accounting guidance is effective prospectively for transfers of financial assets occurring on or after January 1, 2010, and early adoption of this statement is prohibited. Since 2002, Duke Energy Ohio, Duke Energy Indiana, and Duke Energy Kentucky have sold, on a revolving basis, nearly all of their accounts receivable and related collections through Cinergy Receivables, a bankruptcy-remote QSPE. The securitization transaction was structured to meet the criteria for sale accounting treatment, and accordingly, Duke Energy has not consolidated Cinergy Receivables, and the transfers have been accounted for as sales. Upon adoption of this revised accounting guidance, the accounting treatment and/or financial statement presentation of Duke Energy's accounts receivable securitization programs will be impacted as Cinergy Receivables will be consolidated by Duke Energy as of January 1, 2010. See Note 21 for additional information.

*ASC 810 — **Consolidations.*** In June 2009, the FASB amended existing consolidation accounting guidance to eliminate the exemption from consolidation for QSPEs, and clarified, but did not significantly change, the criteria for determining whether an entity meets the definition of a VIE. This revised accounting guidance also requires an enterprise to qualitatively assess the determination of the primary beneficiary of a VIE based on whether that enterprise has both the power to direct matters that most significantly impact the activities of a VIE and the obligation to absorb losses or the right to receive benefits of a VIE that could potentially be significant to a VIE. In addition, this revised accounting guidance modifies existing accounting guidance to require an ongoing evaluation of a VIE's primary beneficiary and amends the types of events that trigger a reassessment of whether an entity is a VIE. Furthermore, this accounting guidance requires enterprises to provide additional disclosures about their involvement with VIEs and any significant changes in their risk exposure due to that involvement. For Duke Energy, this accounting guidance is effective beginning on January 1, 2010, and is applicable to all entities in which Duke Energy is involved with, including entities previously subject to existing accounting guidance for VIEs, as well as any QSPEs that exist as of the effective date. Early adoption of this revised accounting guidance is prohibited. Upon adoption of this revised accounting guidance, the accounting treatment and/or financial statement presentation of Duke Energy's accounts receivable securitization programs will be impacted as Cinergy Receivables will be consolidated by Duke Energy effective January 1, 2010. Duke Energy is currently evaluating the potential impact of the adoption of this revised accounting guidance on its other interests in VIEs and is unable to estimate at this time the impact of adoption on its consolidated results of operations, cash flows or financial position.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

See "Management's Discussion and Analysis of Results of Operations and Financial Condition, Quantitative and Qualitative Disclosures About Market Risk."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Duke Energy Corporation
Charlotte, North Carolina

We have audited the accompanying consolidated balance sheets of Duke Energy Corporation and subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of operations, equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2009. Our audits also included the financial statement schedules listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2009, 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 these financial statements and financial statement schedules, 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 Annual Report On Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on these financial statements and financial statement schedules and an opinion on the Company's internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Duke Energy Corporation and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ DELOITTE & TOUCHE LLP

Charlotte, North Carolina
February 26, 2010

DUKE ENERGY CORPORATION

Consolidated Statements of Operations

	Years Ended December 31,		
(In millions, except per-share amounts)	2009	2008	2007
Operating Revenues			
Regulated electric	$10,033	$ 9,325	$ 8,976
Non-regulated electric, natural gas, and other	2,050	3,092	3,024
Regulated natural gas	648	790	720
Total operating revenues	12,731	13,207	12,720
Operating Expenses			
Fuel used in electric generation and purchased power — regulated	3,246	3,007	2,602
Fuel used in electric generation and purchased power — non-regulated	765	1,400	1,344
Cost of natural gas and coal sold	433	613	557
Operation, maintenance and other	3,313	3,351	3,324
Depreciation and amortization	1,656	1,670	1,746
Property and other taxes	685	639	649
Goodwill and other impairment charges	420	85	—
Total operating expenses	10,518	10,765	10,222
Gains (Losses) on Sales of Other Assets and Other, net	36	69	(5)
Operating Income	2,249	2,511	2,493
Other Income and Expenses			
Equity in earnings (losses) of unconsolidated affiliates	70	(102)	157
Losses on sales and impairments of unconsolidated affiliates	(21)	(9)	—
Other income and expenses, net	284	232	271
Total other income and expenses	333	121	428
Interest Expense	751	741	685
Income From Continuing Operations Before Income Taxes	1,831	1,891	2,236
Income Tax Expense from Continuing Operations	758	616	712
Income From Continuing Operations	1,073	1,275	1,524
Income (Loss) From Discontinued Operations, net of tax	12	16	(22)
Income Before Extraordinary Items	1,085	1,291	1,502
Extraordinary Items, net of tax	—	67	—
Net Income	1,085	1,358	1,502
Less: Net Income (Loss) Attributable to Noncontrolling Interests	10	(4)	2
Net Income Attributable to Duke Energy Corporation	$ 1,075	$ 1,362	$ 1,500
Earnings Per Share — Basic and Diluted			
Income from continuing operations attributable to Duke Energy Corporation common shareholders			
Basic	$ 0.82	$ 1.01	$ 1.21
Diluted	$ 0.82	$ 1.01	$ 1.20
Income from discontinued operations attributable to Duke Energy Corporation common shareholders			
Basic	$ 0.01	$ 0.02	$ (0.02)
Diluted	$ 0.01	$ 0.01	$ (0.02)
Earnings per share (before extraordinary items)			
Basic	$ 0.83	$ 1.03	$ 1.19
Diluted	$ 0.83	$ 1.02	$ 1.18
Earnings per share (from extraordinary items)			
Basic	$ —	$ 0.05	$ —
Diluted	$ —	$ 0.05	$ —
Net income attributable to Duke Energy Corporation common shareholders			
Basic	$ 0.83	$ 1.08	$ 1.19
Diluted	$ 0.83	$ 1.07	$ 1.18
Dividends per share	$ 0.94	$ 0.90	$ 0.86
Weighted-average shares outstanding			
Basic	1,293	1,265	1,260
Diluted	1,294	1,267	1,265

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION

Consolidated Balance Sheets

(In millions)	December 31, 2009	2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,542	$ 986
Short-term investments	—	51
Receivables (net of allowance for doubtful accounts of $48 at December 31, 2009 and $42 at December 31, 2008)	1,741	1,653
Inventory	1,515	1,135
Other	968	1,448
Total current assets	5,766	5,273
Investments and Other Assets		
Investments in equity method unconsolidated affiliates	436	473
Nuclear decommissioning trust funds	1,765	1,436
Goodwill	4,350	4,720
Intangibles, net	593	680
Notes receivable	130	134
Other	2,533	2,577
Total investments and other assets	9,807	10,020
Property, Plant and Equipment		
Cost	55,362	50,304
Less accumulated depreciation and amortization	17,412	16,268
Net property, plant and equipment	37,950	34,036
Regulatory Assets and Deferred Debits		
Deferred debt expense	258	257
Regulatory assets related to income taxes	557	625
Other	2,702	2,866
Total regulatory assets and deferred debits	3,517	3,748
Total Assets	$57,040	$53,077

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION

Consolidated Balance Sheets – (Continued)

	December 31,	
(In millions, except per-share amounts)	2009	2008
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 1,390	$ 1,477
Notes payable and commercial paper	—	543
Taxes accrued	428	362
Interest accrued	222	187
Current maturities of long-term debt	902	646
Other	1,146	1,130
Total current liabilities	4,088	4,345
Long-term Debt	16,113	13,250
Deferred Credits and Other Liabilities		
Deferred income taxes	5,615	5,117
Investment tax credits	310	148
Asset retirement obligations	3,185	2,567
Other	5,843	6,499
Total deferred credits and other liabilities	14,953	14,331
Commitments and Contingencies		
Equity		
Common Stock, $0.001 par value, 2 billion shares authorized; 1,309 million and 1,272 million shares outstanding at December 31, 2009 and December 31, 2008, respectively	1	1
Additional paid-in capital	20,661	20,106
Retained earnings	1,460	1,607
Accumulated other comprehensive loss	(372)	(726)
Total Duke Energy Corporation shareholders' equity	21,750	20,988
Noncontrolling Interests	136	163
Total equity	21,886	21,151
Total Liabilities and Equity	$57,040	$53,077

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION

Consolidated Statements of Cash Flows

	Years Ended December 31,		
(In millions)	2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,085	$ 1,358	$ 1,502
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization (including amortization of nuclear fuel)	1,846	1,834	1,888
Extraordinary items, net of tax	—	(67)	—
(Gains) losses on sales of other assets	(44)	(95)	10
Impairment of goodwill and other impairment charges	449	94	—
Deferred income taxes	941	485	669
Equity in (earnings) loss of unconsolidated affiliates	(70)	102	(157)
Contributions to qualified pension plans	(800)	—	(412)
(Increase) decrease in			
Net realized and unrealized mark-to-market and hedging transactions	4	(33)	—
Receivables	(38)	189	(240)
Inventory	(298)	(209)	(36)
Other current assets	277	(449)	(22)
Increase (decrease) in			
Accounts payable	(80)	(136)	(172)
Taxes accrued	52	47	(134)
Other current liabilities	70	(88)	(321)
Other assets	(9)	236	739
Other liabilities	78	60	(106)
Net cash provided by operating activities	3,463	3,328	3,208
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(4,296)	(4,386)	(3,125)
Investment expenditures	(137)	(147)	(91)
Acquisitions, net of cash acquired	(124)	(389)	(66)
Purchases of available-for-sale securities	(3,013)	(7,353)	(23,639)
Proceeds from sales and maturities of available-for-sale securities	2,988	7,454	24,613
Net proceeds from the sales of other assets, and sales of and collections on notes receivable	70	92	154
Settlement of net investment hedges and other investing derivatives	—	—	(10)
Purchases of emission allowances	(93)	(62)	(103)
Sales of emission allowances	67	104	52
Change in restricted cash	58	115	68
Other	(12)	(39)	(4)
Net cash used in investing activities	(4,492)	(4,611)	(2,151)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the:			
Issuance of long-term debt	4,409	4,794	823
Issuance of common stock related to employee benefit plans	519	133	50
Payments for the redemption of:			
Long-term debt	(1,533)	(2,130)	(1,248)
Convertible notes	—	—	(110)
Decrease in cash overdrafts	—	—	(2)
Notes payable and commercial paper	(548)	(73)	617
Distributions to noncontrolling interests	(37)	(2)	(52)
Contributions from noncontrolling interests	—	6	68
Cash distributed to Spectra Energy	—	—	(395)
Dividends paid	(1,222)	(1,143)	(1,089)
Other	(3)	6	11
Net cash provided by (used in) financing activities	1,585	1,591	(1,327)
Net increase (decrease) in cash and cash equivalents	556	308	(270)
Cash and cash equivalents at beginning of period	986	678	948
Cash and cash equivalents at end of period	$ 1,542	$ 986	$ 678
Supplemental Disclosures:			
Cash paid for interest, net of amount capitalized	$ 689	$ 677	$ 827
Cash (received) paid for income taxes	$ (419)	$ 322	$ 367
Significant non-cash transactions:			
Distribution of Spectra Energy to shareholders	$ —	$ —	$ 5,219
Accrued capital expenditures	$ 428	$ 378	$ 570

See Notes to Consolidated Financial Statements

DUKE ENERGY CORPORATION

Consolidated Statements of Equity and Comprehensive Income

					Accumulated Other Comprehensive Income (Loss)						
(In millions)	Common Stock Shares	Common Stock	Additional Paid-In Capital	Retained Earnings	Foreign Currency Adjustments	Net Gains (Losses) on Cash Flow Hedges	Other	Pension and OPEB Related Adjustments to AOCI	Common Stockholders' Equity	Noncontrolling Interests	Total Equity
Balance at December 31, 2006	1,257	$ 1	$19,854	$ 5,652	$ 949	$(45)	$ 2	$(311)	$26,102	$ 805	$26,907
Net income	—	—	—	1,500	—	—	—	—	1,500	2	1,502
Other Comprehensive Income											
Foreign currency translation adjustments	—	—	—	—	200	—	—	—	200	1	201
Net unrealized losses on cash flow hedges(a)	—	—	—	—	—	(14)	—	—	(14)	—	(14)
Reclassification into earnings from cash flow hedges(b)	—	—	—	—	—	(1)	—	—	(1)	—	(1)
Pension and OPEB related adjustments to AOCI	—	—	—	—	—	—	—	14	14	—	14
Net actuarial gain(c)	—	—	—	—	—	—	—	96	96	—	96
Other(d)	—	—	—	—	—	—	—	1	1	—	1
Total comprehensive income									1,796	3	1,799
Adoption of uncertain tax position accounting standard	—	—	—	(25)	—	—	—	—	(25)	—	(25)
Adoption of pension and OPEB funded status accounting standard	—	—	—	(28)	—	—	—	(22)	(50)	—	(50)
Distribution of Spectra Energy to shareholders	—	—	—	(4,612)	(1,156)	6	—	148	(5,614)	(565)	(6,179)
Purchases and other changes in noncontrolling interest in subsidiaries	—	—	—	—	—	—	—	—	—	(62)	(62)
Dividend reinvestment and employee benefits	5	—	79	—	—	—	—	—	79	—	79
Common stock dividends	—	—	—	(1,089)	—	—	—	—	(1,089)	—	(1,089)
Balance at December 31, 2007	1,262	$ 1	$19,933	$ 1,398	$ (7)	$(54)	$ 2	$ (74)	$21,199	$ 181	$21,380
Net income	—	—	—	1,362	—	—	—	—	1,362	(4)	1,358
Other Comprehensive Income											
Foreign currency translation adjustments	—	—	—	—	(299)	—	—	—	(299)	(16)	(315)
Net unrealized gains on cash flow hedges(a)	—	—	—	—	—	10	—	—	10	—	10
Reclassification into earnings from cash flow hedges(b)	—	—	—	—	—	3	—	—	3	—	3
Pension and OPEB related adjustments to AOCI	—	—	—	—	—	—	—	3	3	—	3
Net actuarial loss(e)	—	—	—	—	—	—	—	(280)	(280)	—	(280)
Unrealized loss on investments in auction rate securities(f)	—	—	—	—	—	—	(28)	—	(28)	—	(28)
Reclassification of losses on investments in auction rate securities and other available-for-sale securities into earnings(g)	—	—	—	—	—	—	8	—	8	—	8
Unrealized loss on investments in available-for-sale securities(h)	—	—	—	—	—	—	(10)	—	(10)	—	(10)
Total comprehensive income									769	(20)	749
Common stock issuances, including dividend reinvestment and employee benefits	10	—	173	—	—	—	—	—	173	—	173
Common stock dividends	—	—	—	(1,143)	—	—	—	—	(1,143)	—	(1,143)
Additional amounts related to the spin-off of Spectra Energy	—	—	—	(10)	—	—	—	—	(10)	2	(8)
Balance at December 31, 2008	1,272	$ 1	$20,106	$ 1,607	$ (306)	$(41)	$(28)	$(351)	$20,988	$ 163	$21,151
Net income				1,075					1,075	10	1,085
Other Comprehensive Income											
Foreign currency translation adjustments	—	—	—	—	323	—	—	—	323	18	341
Net unrealized gain on cash flow hedges(a)	—	—	—	—	—	1	—	—	1	—	1
Reclassification into earnings from cash flow hedges(b)	—	—	—	—	—	18	—	—	18	—	18
Pension and OPEB related adjustments to AOCI(i)	—	—	—	—	—	—	—	36	36	—	36
Net actuarial loss(e)	—	—	—	—	—	—	—	(21)	(21)	—	(21)
Unrealized loss on investments in auction rate securities(f)	—	—	—	—	—	—	(6)	—	(6)	—	(6)
Reclassification of gains on investments in available-for-sale securities into earnings(g)	—	—	—	—	—	—	(5)	—	(5)	—	(5)
Unrealized gain on investments in available-for-sale securities(h)	—	—	—	—	—	—	8	—	8	—	8
Total comprehensive income									1,429	28	1,457
Common stock issuances, including dividend reinvestment and employee benefits	37	—	546	—	—	—	—	—	546	—	546
Purchases and other changes in noncontrolling interest in subsidiaries	—	—	14	—	—	—	—	—	14	(55)	(41)
Common stock dividends	—	—	—	(1,222)	—	—	—	—	(1,222)	—	(1,222)
Other	—	—	(5)	—	—	—	—	—	(5)	—	(5)
Balance at December 31, 2009	1,309	$ 1	$20,661	$ 1,460	$ 17	$(22)	$(31)	$(336)	$21,750	$ 136	$21,886

(a) Net unrealized gains (losses) on cash flow hedges, net of $1 tax expense in 2009, $6 tax expense in 2008 and $9 tax benefit in 2007.
(b) Reclassification into earnings from cash flow hedges, net of $10 tax expense in 2009, $2 tax expense in 2008 and zero in 2007.
(c) Net actuarial gain net of $54 tax expense in 2007.
(d) Net of zero tax expense in 2007.
(e) Net actuarial loss net of $12 tax benefit in 2009 and $159 tax benefit in 2008.
(f) Net of $4 tax benefit in 2009 and $18 tax benefit in 2008.
(g) Net of $2 tax expense in 2009 and $5 tax benefit in 2008.
(h) Net of $4 tax expense in 2009 and $8 tax benefit in 2008.
(i) Net of $16 tax expense in 2009.

See Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Basis of Consolidation.

Duke Energy Corporation (collectively with its subsidiaries, Duke Energy), is an energy company primarily located in the Americas. Duke Energy operates in the United States (U.S.) primarily through its wholly-owned subsidiaries, Duke Energy Carolinas, LLC (Duke Energy Carolinas), Duke Energy Ohio, Inc. (Duke Energy Ohio), Duke Energy Indiana, Inc. (Duke Energy Indiana) and Duke Energy Kentucky, Inc. (Duke Energy Kentucky), as well as in South and Central America through International Energy. See Note 2 for further information on Duke Energy's operations and its reportable business segments. These Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of Duke Energy and all majority-owned subsidiaries where Duke Energy has control, and those variable interest entities where Duke Energy is the primary beneficiary. These Consolidated Financial Statements also reflect Duke Energy's proportionate share of certain generation and transmission facilities in South Carolina, Ohio, Indiana and Kentucky.

On January 2, 2007, Duke Energy completed the spin-off to shareholders of its natural gas businesses. The primary businesses that remained with Duke Energy post-spin are the U.S. Franchised Electric and Gas business segment, the Commercial Power business segment and the International Energy business segment. See Note 2 for further information on Duke Energy's business segments. Assets and liabilities of entities included in the spin-off of Spectra Energy Corp. (Spectra Energy) were transferred from Duke Energy on a historical cost basis on the date of the spin-off transaction. No gain or loss was recognized on the distribution of these operations to Duke Energy shareholders. Approximately $20.5 billion of assets, $14.9 billion of liabilities (which included approximately $8.6 billion of debt) and $5.6 billion of common stockholders' equity (which included approximately $1.0 billion of accumulated other comprehensive income) were distributed from Duke Energy as of the date of the spin-off.

Use of Estimates.

To conform to generally accepted accounting principles (GAAP) in the United States, management makes estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and Notes. Although these estimates are based on management's best available information at the time, actual results could differ.

Cost-Based Regulation.

Duke Energy accounts for certain of its regulated operations in accordance with applicable regulatory accounting guidance. The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers in a future period or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process. Management continually assesses whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. Additionally, management continually assesses whether any regulatory liabilities have been incurred. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery and that no regulatory liabilities, other than those recorded, have been incurred. These regulatory assets and liabilities are primarily classified in the Consolidated Balance Sheets as Regulatory Assets and Deferred Debits and Deferred Credits and Other Liabilities, respectively. Duke Energy periodically evaluates the applicability of regulatory accounting treatment by considering factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, Duke Energy may have to reduce its asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities. For further information see Note 4.

In order to apply regulatory accounting treatment and record regulatory assets and liabilities, certain criteria must be met. In determining whether the criteria are met for its operations, management makes significant judgments, including determining whether revenue rates for services provided to customers are subject to approval by an independent, third-party regulator, whether the regulated rates are designed to recover specific costs of providing the regulated service, and a determination of whether, in view of the demand for the regulated services and the level of competition, it is reasonable to assume that rates set at levels that will recover the operations' costs can be charged to and collected from customers. This final criterion requires consideration of anticipated changes in levels of demand or competition, direct and indirect, during the recovery period for any capitalized costs. If facts and circumstances change so that a portion of Duke Energy's regulated operations meet all of the scope criteria when such criteria had not been previously met, regulatory accounting treatment would be reapplied to all or a separable portion of the operations. Such reapplication includes adjusting the balance sheet for amounts that meet the definition of a regulatory asset or regulatory liability. Refer to the following section titled, "Reapplication of Regulatory Accounting Treatment to Portions of Generation in Ohio."

Fuel Cost Deferrals.

Fuel expense includes fuel costs or other recoveries that are deferred through fuel clauses established by Duke Energy's regulators. These clauses allow Duke Energy 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.

Reapplication of Regulatory Accounting Treatment to Portions of Generation in Ohio.

Commercial Power's generation operations in the Midwest include generation assets located in Ohio that are dedicated to serve Ohio native load customers. These assets, as excess capacity allows, also generate revenues through sales outside the native load customer base, and such revenue is termed non-native.

Prior to December 17, 2008, Commercial Power did not apply regulatory accounting treatment to any of its operations due to the comprehensive electric deregulation legislation passed by the state of Ohio in 1999. As discussed further in Note 4, in April 2008, new legislation, Ohio Senate Bill 221 (SB 221), was passed in Ohio and signed by the Governor of Ohio on May 1, 2008. The new law codified the Public Utilities Commission of Ohio's (PUCO) authority to approve an electric utility's standard service offer either through an Electric Security Plan (ESP) or a Market Rate Option (MRO), which is a price determined through a competitive bidding process. On July 31, 2008, Duke Energy Ohio filed an ESP and, with certain amendments, the ESP was approved by the PUCO on December 17, 2008. The approval of the ESP on December 17, 2008 resulted in the reapplication of regulatory accounting treatment to certain portions of Commercial Power's operations as of that date The ESP became effective on January 1, 2009.

From January 1, 2005 through December 31, 2008, Commercial Power operated under a Rate Stabilization Plan (RSP), which was a market-based standard service offer. Although the RSP contained certain trackers that enhanced the potential for cost recovery, there was no assurance of stranded cost recovery upon the expiration of the RSP on December 31, 2008 since it was initially anticipated that there would be a move to full competitive markets upon the expiration of the RSP. Accordingly, Commercial Power did not apply regulatory accounting treatment to any of its generation operations prior to December 17, 2008. In connection with the approval of the ESP, Duke Energy reassessed whether Commercial Power's generation operations met the criteria for regulatory accounting treatment as SB 221 substantially increased the PUCO's oversight authority over generation in the state of Ohio, including giving the PUCO complete approval of generation rates and the establishment of an earnings test to determine if a utility has earned significantly excessive earnings. Duke Energy determined that certain costs and related rates (riders) of Commercial Power's operations related to generation serving native load met the necessary accounting criteria for regulatory accounting treatment as SB 221 and Duke Energy Ohio's approved ESP enhanced the recovery mechanism for certain costs of its generation serving native load and increased the likelihood that these operations will remain under a cost recovery model for certain costs for the remainder of the ESP period.

Under the ESP, Commercial Power bills for its native load generation via numerous riders. SB 221 and the ESP resulted in the approval of an enhanced recovery mechanism for certain of these riders, which includes, but is not limited to, a price-to-compare fuel and purchased power rider and certain portions of a price-to-compare cost of environmental compliance rider. Accordingly, Commercial Power began applying regulatory accounting treatment to the corresponding RSP riders that enhanced the recovery mechanism for recovery under the ESP on December 17, 2008. The remaining portions of Commercial Power's Ohio native load generation operations, revenues from which are reflected in rate riders for which the ESP does not specifically allow enhanced recovery, as well as all generation operations associated with non-native customers, including Commercial Power's Midwest gas-fired generation assets, continue to not apply regulatory accounting as those operations do not meet the necessary accounting criteria. Moreover, generation remains a competitive market in Ohio and native load customers continue to have the ability to switch to alternative suppliers for their electric generation service. As customers switch, there is a risk that some or all of the regulatory assets will not be recovered through the established riders. In assessing the probability of recovery of its regulatory assets established for its native load generation operations, Duke Energy continues to monitor the amount of native load customers that have switched to alternative suppliers. At December 31, 2009, management has concluded that the established regulatory assets are still probable of recovery even though there have been increased levels of customer switching.

Despite certain portions of the Ohio native load operations not meeting the criteria for applying regulatory accounting treatment, all of Commercial Power's Ohio native load operations' rates are subject to approval by the PUCO, and thus these operations are referred to here-in as Commercial Power's regulated operations. Accordingly, beginning January 1, 2009, these revenues and corresponding fuel and purchased power expenses are recorded in Regulated Electric within Operating Revenues and Fuel Used in Electric Generation and Purchased Power — Regulated within Operating Expense, respectively, on the Consolidated Statements of Operations.

The reapplication of regulatory accounting treatment to generation in Ohio on December 17, 2008, as discussed above, resulted in an approximate $67 million after-tax (approximately $103 million pre-tax) extraordinary gain related to mark-to-market losses previously recorded in earnings associated with open forward native load economic hedge contracts for fuel, purchased power and emission allowances, which the RSP and ESP allow to be recovered through a fuel and purchase power (FPP) rider. There were no other immediate income statement impacts on the date of reapplication of regulatory accounting. A corresponding regulatory asset was established for the value of these contracts.

Cash and Cash Equivalents.

All highly liquid investments with maturities of three months or less at the date of acquisition are considered cash equivalents.

Restricted Cash.

At December 31, 2009 and 2008, Duke Energy had approximately $38 million and $85 million, respectively, of restricted cash related primarily to proceeds from debt issuances that are held in trust for the purpose of funding future environmental construction or maintenance expenditures. Restricted cash balances are reflected within both Other within Current Assets and Other within Investments and Other Assets on the Consolidated Balance Sheets.

Inventory.

Inventory is comprised of amounts presented in the table below and is recorded primarily using the average cost method. Inventory related to Duke Energy's regulated operations is valued at historical cost consistent with ratemaking treatment. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to plant when installed. Inventory related to Duke Energy's non-regulated operations is valued at the lower of cost or market.

Components of Inventory

	December 31,	
(in millions)	2009	2008
Materials and supplies	$ 705	$ 661
Coal held for electric generation	748	471
Natural gas	62	3
Total inventory	$1,515	$1,135

Effective November 1, 2008, Duke Energy Ohio and Duke Energy Kentucky executed agreements with a third party to transfer title of natural gas inventory purchased by Duke Energy Ohio and Duke Energy Kentucky to the third party. Under the agreements, the gas inventory was stored and managed for Duke Energy Ohio and Duke Energy Kentucky and was delivered on demand. As a result of the agreements, the combined natural gas inventory of approximately $81 million being held by a third party as of December 31, 2008 was classified as Other within Current Assets on the Consolidated Balance Sheets.

The gas storage agreements noted above expired on October 31, 2009. Effective November 1, 2009, Duke Energy Ohio and Duke Energy Kentucky executed agreements with a different third party. Under the new agreements, the gas inventory is being stored and managed for Duke Energy Ohio and Duke Energy Kentucky and will be delivered on demand. However, title of the natural gas inventory remains with Duke Energy Ohio and Duke Energy Kentucky. The new gas storage agreements will expire on October 31, 2011.

Investments in Debt and Equity Securities.

Duke Energy classifies investments into two categories — trading and available-for-sale. Trading securities are reported at fair value in the Consolidated Balance Sheets with net realized and unrealized gains and losses included in earnings each period. Available-for-sale securities are also reported at fair value on the Consolidated Balance Sheets with unrealized gains and losses included in Accumulated Other Comprehensive Income (AOCI) or a regulatory asset or liability, unless it is determined that the carrying value of an investment is other-than-temporarily impaired. Other-than-temporary impairments related to equity securities and the credit loss portion of debt securities are included in earnings, unless deferred in accordance with regulatory accounting treatment. Investments in debt and equity securities are classified as either short-term investments or long-term investments based on management's intent and ability to sell these securities, taking into consideration illiquidity factors in the current markets with respect to certain investments that have historically provided for a high degree of liquidity, such as investments in auction rate debt securities.

See Note 10 for further information on the investments in debt and equity securities, including investments held in the Nuclear Decommissioning Trust Fund (NDTF).

Goodwill.

Duke Energy performs an annual goodwill impairment test as of August 31 each year and updates the test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. Duke Energy performs the annual review for goodwill impairment at the reporting unit level, which Duke Energy has determined to be an operating segment or one level below.

The annual test of the potential impairment of goodwill requires a two step process. Step one of the impairment test involves comparing the estimated fair values of reporting units with their aggregate carrying values, including goodwill. If the carrying amount of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of the goodwill impairment loss. If the carrying amount is less than fair value, further testing of goodwill impairment is not performed.

Step two of the goodwill impairment test involves comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. Under step two, determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The difference between the fair value of the entire reporting unit as determined in step one and the net fair value of all identifiable assets and liabilities represents the implied fair value of goodwill. The goodwill impairment charge, if any, would be the difference between the carrying amount of goodwill and the implied fair value of goodwill upon the completion of step two.

For purposes of the step one analyses, determination of reporting units' fair value is typically based on a combination of the income approach, which estimates the fair value of Duke Energy's reporting units based on discounted future cash flows, and the market approach, which estimates the fair value of Duke Energy's reporting units based on market comparables within the utility and energy industries.

See Note 11 for further information, including discussion of an approximate $371 million goodwill impairment charge recorded during the year ended December 31, 2009.

Long-Lived Asset Impairments.

Duke Energy evaluates whether long-lived assets, excluding goodwill, have been impaired when circumstances indicate the carrying value of those assets may not be recoverable. For such long-lived assets, an impairment exists when its carrying value exceeds the sum of estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used for developing estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, the impairment loss is measured as the excess of the carrying value of the asset over its fair value, such that the asset's carrying value is adjusted to its estimated fair value.

Management assesses the fair value of long-lived assets using commonly accepted techniques, and may use more than one source. Sources to determine fair value include, but are not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors. Significant changes in market conditions resulting from events such as, among others, changes in commodity prices or the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to re-assess the cash flows related to the long-lived assets.

See Note 11 for further information regarding a long-lived asset impairment charge recorded during the year ended December 31, 2009.

Property, Plant and Equipment.

Property, plant and equipment are stated at the lower of historical cost less accumulated depreciation or fair value, if impaired. For regulated operations, Duke Energy capitalizes all construction-related direct labor and material costs, as well as indirect construction costs. Indirect costs include general engineering, taxes and the cost of funds used during construction (see "Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized," discussed below). The cost of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects, which do not extend the useful life or increase the expected output of the asset, is expensed as incurred. Depreciation is generally computed over the estimated useful life of the asset using the composite straight-line method. The composite weighted-average depreciation rates, excluding nuclear fuel, were 3.30% for 2009, 3.11% for 2008, and 3.19% for 2007. Depreciation studies are conducted periodically to update the composite rates and are approved by the various state commissions.

When Duke Energy retires its regulated property, plant and equipment, it charges the original cost plus the cost of retirement, less salvage value, to accumulated depreciation. When it sells entire regulated operating units, or retires or sells non-regulated properties, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

See Note 14 for further information on the components and estimated useful lives of Duke Energy's property, plant and equipment balance.

Nuclear Fuel.

Amortization of nuclear fuel purchases is included within Fuel Used in Electric Generation and Purchased Power-Regulated in the Consolidated Statements of Operations. The amortization is recorded using the units-of-production method.

Allowance for Funds Used During Construction and Interest Capitalized.

In accordance with applicable regulatory accounting guidance, Duke Energy records AFUDC, which represents the estimated debt and equity costs of capital funds necessary to finance the construction of new regulated facilities. Both the debt and equity components of AFUDC are non-cash amounts within the Consolidated Statements of Operations. AFUDC is capitalized as a component of the cost of Property, Plant and Equipment, with an offsetting credit to Other Income and Expenses, net on the Consolidated Statements of Operations for the equity component and as an offset to Interest Expense on the Consolidated Statements of Operations for the debt component. After construction is completed, Duke Energy is permitted to recover these costs through inclusion in the rate base and the corresponding depreciation expense or nuclear fuel expense.

AFUDC equity is recorded in the Consolidated Statements of Operations on an after-tax basis and is a permanent difference item for income tax purposes (i.e., a permanent difference between financial statement and income tax reporting), thus reducing Duke

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Energy's income tax expense and effective tax rate during the construction phase in which AFUDC equity is being recorded. The effective tax rate is subsequently increased in future periods when the completed property, plant and equipment is placed in service and depreciation of the AFUDC equity commences. See Note 6 for information related to the impacts of AFUDC equity on Duke Energy's effective tax rate.

For non-regulated operations, interest is capitalized during the construction phase in accordance with the applicable accounting guidance.

Asset Retirement Obligations.

Duke Energy recognizes asset retirement obligations for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset, and for conditional asset retirement obligations. The term conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. When recording an asset retirement obligation, the present value of the projected liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The present value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the estimated useful life of the asset. See Note 7 for further information regarding Duke Energy's asset retirement obligations.

Revenue Recognition and Unbilled Revenue.

Revenues on sales of electricity and gas are recognized when either the service is provided or the product is delivered. Operating revenues include unbilled electric and gas revenues earned when service has been delivered but not billed by the end of the accounting period. Unbilled retail revenues are estimated by applying an average revenue per kilowatt-hour (kWh) or per thousand cubic feet (Mcf) for all customer classes to the number of estimated kWh or Mcfs delivered but not billed. Unbilled wholesale energy revenues are calculated by applying the contractual rate per megawatt-hour (MWh) to the number of estimated MWh delivered but not yet billed. Unbilled wholesale demand revenues are calculated by applying the contractual rate per megawatt (MW) to the MW volume delivered but not yet billed. The amount of unbilled revenues can vary significantly from period to period as a result of numerous factors, including seasonality, weather, customer usage patterns and customer mix. Unbilled revenues, which are primarily recorded as Receivables on the Consolidated Balance Sheets and exclude receivables sold to Cinergy Receivables Company, LLC (Cinergy Receivables), were approximately $460 million and $390 million at December 31, 2009 and 2008, respectively. Additionally, Duke Energy Ohio, Duke Energy Kentucky and Duke Energy Indiana sell, on a revolving basis, nearly all of their retail accounts receivable and a portion of their wholesale accounts receivable and related collections to Cinergy Receivables, a bankruptcy remote, special purpose entity that is a wholly-owned limited liability company of Cinergy Corp. (Cinergy), a wholly-owned subsidiary of Duke Energy. The securitization transaction was structured to meet the criteria for sale accounting treatment under the accounting guidance for transfers and servicing of financial assets and, accordingly, the transfers of receivables are accounted for as sales. Receivables for unbilled retail and wholesale revenues of approximately $238 million and $266 million at December 31, 2009 and 2008, respectively, were included in the sales of accounts receivables to Cinergy Receivables. See Note 21 for additional information regarding Cinergy Receivables including the impacts of adoption of new accounting rules which require the consolidation of Cinergy Receivables.

Accounting for Risk Management, Hedging Activities and Financial Instruments.

Duke Energy may use a number of different derivative and non-derivative instruments in connection with its commodity price, interest rate and foreign currency risk management activities, including swaps, futures, forwards and options. All derivative instruments not designated as hedges and not qualifying for the normal purchase/normal sale (NPNS) exception within the accounting guidance for derivatives are recorded on the Consolidated Balance Sheets at their fair value. Duke Energy may designate qualifying derivative instruments as either cash flow hedges or fair value hedges, while others either have not been designated as hedges or do not qualify as a hedge (hereinafter referred to as undesignated contracts). For all contracts accounted for as a hedge, Duke Energy prepares formal documentation of the hedge in accordance with the accounting guidance for derivatives. In addition, at inception and at least every three months thereafter, Duke Energy formally assesses whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. Duke Energy documents hedging activity by transaction type (futures/swaps) and risk management strategy (commodity price risk/interest rate risk).

See Note 8 for additional information and disclosures regarding risk management activities and derivative transactions and balances.

Captive Insurance Reserves.

Duke Energy has captive insurance subsidiaries which provide insurance coverage, on an indemnity basis, to Duke Energy entities as well as certain third parties, on a limited basis, for various business risks and losses, such as property, business interruption and general liability. Liabilities include provisions for estimated losses incurred but not yet reported (IBNR), as well as provisions for known claims which have been estimated on a claims-incurred basis. IBNR reserve estimates involve the use of assumptions and are primarily based upon historical loss experience, industry data and other actuarial assumptions. Reserve estimates are adjusted in future periods as actual losses differ from historical experience.

Duke Energy, through its captive insurance entities, also has reinsurance coverage, which provides reimbursement to Duke Energy for certain losses above a per incident and/or aggregate retention. Duke Energy recognizes a reinsurance receivable for recovery of incurred losses under its captive's reinsurance coverage once realization of the receivable is deemed probable by its captive insurance companies.

Unamortized Debt Premium, Discount and Expense.

Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the terms of the debt issues. Any call premiums or unamortized expenses associated with refinancing higher-cost debt obligations to finance regulated assets and operations are amortized consistent with regulatory treatment of those items, where appropriate. The amortization expense is recorded as a component of interest expense in the Consolidated Statements of Operations and is reflected as Depreciation and amortization within Net cash provided by operating activities on the Consolidated Statements of Cash Flows.

Loss Contingencies and Environmental Liabilities.

Duke Energy is involved in certain legal and environmental matters that arise in the normal course of business. Contingent losses are recorded when it is determined that it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, Duke Energy records a loss contingency at the minimum amount in the range. Unless otherwise required by GAAP, legal fees are expensed as incurred. Environmental liabilities are recorded on an undiscounted basis when the necessity for environmental remediation becomes probable and the costs can be reasonably estimated, or when other potential environmental liabilities are reasonably estimable and probable. Duke Energy expenses environmental expenditures related to conditions caused by past operations that do not generate current or future revenues. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate.

See Note 16 for further information.

Pension and Other Post-Retirement Benefit Plans.

Duke Energy maintains qualified, non-qualified and other post-retirement benefit plans. See Note 20 for information related to Duke Energy's benefit plans, including certain accounting policies associated with these plans.

Severance and Special Termination Benefits.

Duke Energy has an ongoing severance plan under which, in general, the longer a terminated employee worked prior to termination the greater the amount of severance benefits. Duke Energy records a liability for involuntary severance once an involuntary severance plan is committed to by management, or sooner, if involuntary severances are probable and the related severance benefits can be reasonably estimated. For involuntary severance benefits that are incremental to its ongoing severance plan benefits, Duke Energy measures the obligation and records the expense at its fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the service period. From time to time, Duke Energy offers special termination benefits under voluntary severance programs. Special termination benefits are measured upon employee acceptance and recorded immediately absent a significant retention period. If a significant retention period exists, the cost of the special termination benefits are recorded ratably over the remaining service periods of the affected employees. Employee acceptance of voluntary severance benefits is determined by management based on the facts and circumstances of the special termination benefits being offered.

Guarantees.

Upon issuance or modification of a guarantee, Duke Energy recognizes a liability at the time of issuance or material modification for the estimated fair value of the obligation it assumes under that guarantee, if any. Fair value is estimated using a probability-weighted approach. Duke Energy reduces the obligation over the term of the guarantee or related contract in a systematic and rational method as risk is reduced under the obligation. Any additional contingent loss for guarantee contracts subsequent to the initial recognition of a liability in accordance with applicable accounting guidance is accounted for and recognized at the time a loss is probable and the amount of the loss can be reasonably estimated.

Duke Energy has entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time, depending on the nature of the claim. Duke Energy's potential exposure under these indemnification agreements can range from a specified to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. See Note 17 for further information.

Stock-Based Compensation.

For employee awards, equity classified stock-based compensation cost is measured at the grant date, based on the fair value of the award, and is recognized as expense over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible. Share-based awards, including stock options, granted to employees that are already retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted. See Note 19 for further information.

Other Liabilities.

At December 31, 2009 and 2008, approximately $257 million and $195 million, respectively, of liabilities associated with vacation accrued are included in Other within Current Liabilities on the Consolidated Balance Sheets. As of December 31, 2009, this balance exceeded 5% of total current liabilities.

Accounting For Purchases and Sales of Emission Allowances.

Emission allowances are issued by the Environmental Protection Agency (EPA) at zero cost and permit the holder of the allowance to emit certain gaseous by-products of fossil fuel combustion, including sulfur dioxide (SO_2) and nitrogen oxide (NO_x). Allowances may also be bought and sold via third party transactions or consumed as the emissions are generated. Allowances allocated to or acquired by Duke Energy are held primarily for consumption. Duke Energy records emission allowances as Intangible Assets on its Consolidated Balance Sheets at cost and recognizes the allowances in earnings as they are consumed or sold. Gains or losses on sales of emission allowances by regulated businesses that do not provide for direct recovery through a cost tracking mechanism and non-regulated businesses are presented on a net basis in Gains (Losses) on Sales of Other Assets and Other, net, in the accompanying Consolidated Statements of Operations. For regulated businesses that provide for direct recovery of emission allowances, any gain or loss on sales of recoverable emission allowances are included in the rate structure of the regulated entity and are deferred as a regulatory asset or liability. Future rates charged to retail customers are impacted by any gain or loss on sales of recoverable emission allowances and, therefore, as the recovery of the gain or loss is recognized in operating revenues, the regulatory asset or liability related to the emission allowance activity is recognized as a component of Fuel Used in Electric Generation and Purchased Power-Regulated in the Consolidated Statements of Operations. Purchases and sales of emission allowances are presented gross as investing activities on the Consolidated Statements of Cash Flows. See Note 11 for discussion regarding the impairment of the carrying value of certain emission allowances in 2008.

Income Taxes.

Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and foreign jurisdictional returns as required. Deferred income taxes have been provided for temporary differences between the GAAP and tax carrying amounts of assets and liabilities. These differences create taxable or tax-deductible amounts for future periods. Investment tax credits (ITC) associated with regulated operations are deferred and are amortized as a reduction of income tax expense over the estimated useful lives of the related properties.

Duke Energy records unrecognized tax benefits for positions taken or expected to be taken on tax returns, including the decision to exclude certain income or transactions from a return, when a more-likely-than-not threshold is met for a tax position and management believes that the position will be sustained upon examination by the taxing authorities. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Duke Energy records the largest amount of the unrecognized tax benefit that is greater than 50% likely of being realized upon settlement or effective settlement. Management considers a tax position effectively settled for the purpose of recognizing previously unrecognized tax benefits when the following conditions exist: (i) the taxing authority has completed its examination procedures, including all appeals and administrative reviews that the taxing authority is required and expected to perform for the tax positions, (ii) Duke Energy does not intend to appeal or litigate any aspect of the tax position included in the completed examination, and (iii) it is remote that the taxing authority would examine or reexamine any aspect of the tax position. See Note 6 for further information.

Deferred taxes are not provided on translation gains and losses where Duke Energy expects earnings of a foreign operation to be indefinitely reinvested.

Duke Energy records, as it relates to taxes, interest expense as Interest Expense and interest income and penalties in Other Income and Expenses, net, in the Consolidated Statements of Operations.

Accounting for Renewable Energy Tax Credits and Grants Under the American Recovery Act of 2009.

In 2009, The American Recovery and Reinvestment Act of 2009 (the Stimulus Bill) was signed into law, which provides tax incentives in the form of ITC or cash grants for renewable energy facilities and renewable generation property either placed in service through specified dates or for which construction has begun prior to specified dates. Under the Stimulus Bill, Duke Energy may elect an ITC, which is determined based on a percentage of the tax basis of the qualified property placed in service, for property placed in service after 2008 and before 2014 (2013 for wind facilities) or a cash grant, which allows entities to elect to receive a cash grant in lieu of the ITC for certain property either placed in service in 2009 or 2010 or for which construction begins in 2009 and 2010. When Duke Energy elects either the ITC or cash grant on Commercial Power's wind facilities that meet the stipulations of the Stimulus Bill, Duke Energy reduces the basis of the property recorded on the Consolidated

Balance Sheets by the amount of the ITC or cash grant and, therefore, the ITC or grant benefit is recognized ratably over the life of the associated asset. Additionally, certain tax credits and government grants received under the Stimulus Bill provide for an incremental initial tax depreciable base in excess of the carrying value for GAAP purposes, creating an initial deferred tax asset equal to the tax effect of one half of the ITC or government grant. Duke Energy records the deferred tax benefit as a reduction to income tax expense in the period that the basis difference is created.

Excise Taxes.

Certain excise taxes levied by state or local governments are collected by Duke Energy from its customers. These taxes, which are required to be paid regardless of Duke Energy's ability to collect from the customer, are accounted for on a gross basis. When Duke Energy acts as an agent, and the tax is not required to be remitted if it is not collected from the customer, the taxes are accounted for on a net basis. Duke Energy's excise taxes accounted for on a gross basis and recorded as operating revenues in the accompanying Consolidated Statements of Operations were approximately $276 million, $278 million and $277 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Foreign Currency Translation.

The local currencies of Duke Energy's foreign operations have been determined to be their functional currencies, except for certain foreign operations whose functional currency has been determined to be the U.S. Dollar, based on an assessment of the economic circumstances of the foreign operation. Assets and liabilities of foreign operations, except for those whose functional currency is the U.S. Dollar, are translated into U.S. Dollars at the exchange rates at period end. Translation adjustments resulting from fluctuations in exchange rates are included as a separate component of AOCI. Revenue and expense accounts of these operations are translated at average exchange rates prevailing during the year. Gains and losses arising from balances and transactions denominated in currencies other than the functional currency are included in the results of operations in the period in which they occur. See Note 22 for additional information on gains and losses primarily associated with International Energy's remeasurement of certain cash and debt balances into the reporting entity's functional currency and transaction gains and losses.

Statements of Consolidated Cash Flows.

Duke Energy has made certain classification elections within its Consolidated Statements of Cash Flows. Cash flows from discontinued operations are combined with cash flows from continuing operations within operating, investing and financing cash flows within the Consolidated Statements of Cash Flows. With respect to cash overdrafts, book overdrafts are included within operating cash flows while bank overdrafts are included within financing cash flows.

Dividend Restrictions and Unappropriated Retained Earnings.

Duke Energy does not have any legal, regulatory or other restrictions on paying common stock dividends to shareholders. However, as further described in Note 4, due to conditions established by regulators at the time of the Duke Energy/Cinergy merger in April 2006, certain wholly-owned subsidiaries have restrictions on paying dividends or otherwise advancing funds to Duke Energy. At December 31, 2009 and 2008, an insignificant amount of Duke Energy's consolidated Retained Earnings balance represents undistributed earnings of equity method investments.

New Accounting Standards.

The following new accounting standards were adopted by Duke Energy during the year ended December 31, 2009 and the impact of such adoption, if applicable has been presented in the accompanying Consolidated Financial Statements:

Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) 105 — Generally Accepted Accounting Principles (ASC 105). In June 2009, the FASB amended ASC 105 for the ASC, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. Rules and interpretive releases of the Securities and Exchange Commission (SEC) under authority of federal securities laws are also sources of authoritative GAAP. On the effective date of the changes to ASC 105, which was for financial statements issued for interim and annual periods ending after September 15, 2009, the ASC supersedes all then-existing non-SEC accounting and reporting standards. Under the ASC, all of its content carries the same level of authority and the GAAP hierarchy includes only two levels of GAAP: authoritative and non-authoritative. While the adoption of the ASC did not have an impact on the accounting followed in Duke Energy's consolidated financial statements, the ASC impacted the references to authoritative and non-authoritative accounting literature contained within the Notes.

ASC 805 — Business Combinations (ASC 805). In December 2007, the FASB issued revised guidance related to the accounting for business combinations. This revised guidance retained the fundamental requirement that the acquisition method of accounting be used for all business combinations and that an acquirer be identified for each business combination. This statement also established principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling (minority) interests in an acquiree, and any goodwill acquired in a business combination or gain recognized from a bargain purchase. For Duke Energy, this revised guidance is applied prospectively to business combinations for which the acquisition date occurred on or after

January 1, 2009. The impact to Duke Energy of applying this revised guidance for periods subsequent to implementation will be dependent upon the nature of any transactions within the scope of ASC 805 The revised guidance of ASC 805 changed the accounting for income taxes related to prior business combinations, such as Duke Energy's merger with Cinergy. Effective January 1, 2009, the resolution of any tax contingencies relating to Cinergy that existed as of the date of the merger are required to be reflected in the Consolidated Statements of Operations instead of being reflected as an adjustment to the purchase price via an adjustment to goodwill.

ASC 810 — Consolidations (ASC 810). In December 2007, the FASB amended ASC 810 to establish accounting and reporting standards for the noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary and to clarify that a noncontrolling interest in a subsidiary is an ownership interest in a consolidated entity that should be reported as equity in the consolidated financial statements. This amendment also changed the way the consolidated income statement is presented by requiring consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. In addition, this amendment established a single method of accounting for changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation. For Duke Energy, this amendment was effective as of January 1, 2009, and has been applied prospectively, except for certain presentation and disclosure requirements that were applied retrospectively. The adoption of these provisions of ASC 810 impacted the presentation of noncontrolling interests in Duke Energy's Consolidated Financial Statements, as well as the calculation of Duke Energy's effective tax rate.

ASC 815 — Derivatives and Hedging (ASC 815). In March 2008, the FASB amended and expanded the disclosure requirements for derivative instruments and hedging activities required under ASC 815. The amendments to ASC 815 requires qualitative disclosures about objectives and strategies for using derivatives, volumetric data, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. Duke Energy adopted these disclosure requirements as of January 1, 2009. The adoption of the amendments to ASC 815 did not have any impact on Duke Energy's consolidated results of operations, cash flows or financial position. See Note 8 for the disclosures required under ASC 815.

ASC 715 — Compensation — Retirement Benefits (ASC 715). In December 2008, the FASB amended ASC 715 to require more detailed disclosures about employers' plan assets, concentrations of risk within plan assets, and valuation techniques used to measure the fair value of plan assets. Additionally, companies will be required to disclose their pension assets in a fashion consistent with ASC 820 — *Fair Value Measurements and Disclosures* (i.e., Level 1, 2, and 3 of the fair value hierarchy) along with a roll-forward of the Level 3 values each year. For Duke Energy, these amendments to ASC 715 were effective for Duke Energy's Form 10-K for the year ended December 31, 2009. The adoption of these new disclosure requirements did not have any impact on Duke Energy's results of operations, cash flows or financial position. See Note 20 for the disclosures required under ASC 715.

The following new accounting standards were adopted by Duke Energy during the year ended December 31, 2008 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

ASC 820 — Fair Value Measurements and Disclosures (ASC 820). Refer to Note 9 for required fair value disclosures.

ASC 825 — Financial Instruments (ASC 825). ASC 825 permits, but does not require, entities to elect to measure many financial instruments and certain other items at fair value. See Note 9.

ASC 860 — Transfers and Servicing (ASC 860) and ASC 810. In December 2008, the FASB amended the disclosure requirements related to transfers and servicing of financial assets and variable interest entities (VIEs) to require public entities to provide additional disclosures about transfers of financial assets and to require public enterprises to provide additional disclosures about their involvement with VIEs. Additionally, certain disclosures were required to be provided by a public enterprise that is (a) a sponsor that has a variable interest in a VIE and (b) an enterprise that holds a significant variable interest in a qualifying special-purpose entity (QSPE) but was not the transferor (nontransferor enterprise) of financial assets to the QSPE. The new disclosure requirements are intended to provide greater transparency to financial statement users about a transferor's continuing involvement with transferred financial assets and an enterprise's involvement with VIEs. The new disclosure requirements were effective for Duke Energy beginning December 31, 2008. The additional requirements of ASC 810 did not have any impact on Duke Energy's consolidated results of operations, cash flows or financial position. See Note 21 for additional information.

The following new accounting standards were adopted by Duke Energy during the year ended December 31, 2007 and the impact of such adoption, if applicable, has been presented in the accompanying Consolidated Financial Statements:

ASC 715. In October 2006, the FASB issued accounting rules that changed the recognition and disclosure provisions and measurement date requirements for an employer's accounting for defined benefit pension and other post-retirement plans. The recognition and disclosure provisions require an employer to (1) recognize the funded status of a benefit plan — measured as the difference between plan assets at fair value and the benefit obligation — in its statement of financial position, (2) recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost, and (3) disclose in the notes to financial statements certain additional information. These new accounting rules did not change the amounts recognized in the income statement as net periodic benefit cost. Duke Energy recognized the funded status of its defined benefit pension and other post-retirement plans and provided the required additional disclosures as of December 31, 2006. The adoption of these new accounting rules did not have a material impact on Duke Energy's consolidated results of operations or cash flows.

Under the new measurement date requirements, an employer is required to measure defined benefit plan assets and obligations as of the date of the employer's fiscal year-end statement of financial position (with limited exceptions). Historically, Duke Energy measured its plan assets and obligations up to three months prior to the fiscal year-end, as allowed under the authoritative accounting literature. Duke Energy adopted the change in measurement date effective January 1, 2007 by remeasuring plan assets and benefit obligations as of that date, pursuant to the transition requirements of the new accounting rules. See Note 20.

ASC 740 — Income Taxes (ASC 740). In July 2006, the FASB provided new guidance on accounting for income tax positions about which Duke Energy has concluded there is a level of uncertainty with respect to the recognition of a tax benefit in Duke Energy's financial statements. This guidance prescribed the minimum recognition threshold a tax position is required to meet. Tax positions are defined very broadly and include not only tax deductions and credits but also decisions not to file in a particular jurisdiction, as well as the taxability of transactions. Duke Energy adopted this new accounting guidance effective January 1, 2007. See Note 6 for additional information.

The following new Accounting Standard Updates (ASU) have been issued, but have not yet been adopted by Duke Energy, as of December 31, 2009:

ASC 860. In June 2009, the FASB issued revised accounting guidance for transfers and servicing of financial assets and extinguishment of liabilities, to require additional information about transfers of financial assets, including securitization transactions, as well as additional information about an enterprise's continuing exposure to the risks related to transferred financial assets. This revised accounting guidance eliminates the concept of a qualifying special-purpose entity (QSPE) and requires those entities which were not subject to consolidation under previous accounting rules to now be assessed for consolidation. In addition, this accounting guidance clarifies and amends the derecognition criteria for transfers of financial assets (including transfers of portions of financial assets) and requires additional disclosures about a transferor's continuing involvement in transferred financial assets. For Duke Energy, this revised accounting guidance is effective prospectively for transfers of financial assets occurring on or after January 1, 2010, and early adoption of this statement is prohibited. Since 2002, Duke Energy Ohio, Duke Energy Indiana, and Duke Energy Kentucky have sold, on a revolving basis, nearly all of their accounts receivable and related collections through Cinergy Receivables, a bankruptcy-remote QSPE. The securitization transaction was structured to meet the criteria for sale accounting treatment, and accordingly, Duke Energy has not consolidated Cinergy Receivables, and the transfers have been accounted for as sales. Upon adoption of this revised accounting guidance, the accounting treatment and/or financial statement presentation of Duke Energy's accounts receivable securitization programs will be impacted as Cinergy Receivables will be consolidated by Duke Energy as of January 1, 2010. See Note 21 for additional information.

ASC 810. In June 2009, the FASB amended existing consolidation accounting guidance to eliminate the exemption from consolidation for QSPEs, and clarified, but did not significantly change, the criteria for determining whether an entity meets the definition of a VIE. This revised accounting guidance also requires an enterprise to qualitatively assess the determination of the primary beneficiary of a VIE based on whether that enterprise has both the power to direct matters that most significantly impact the activities of a VIE and the obligation to absorb losses or the right to receive benefits of a VIE that could potentially be significant to a VIE. In addition, this revised accounting guidance modifies existing accounting guidance to require an ongoing evaluation of a VIE's primary beneficiary and amends the types of events that trigger a reassessment of whether an entity is a VIE. Furthermore, this accounting guidance requires enterprises to provide additional disclosures about their involvement with VIEs and any significant changes in their risk exposure due to that involvement. For Duke Energy, this accounting guidance is effective beginning on January 1, 2010, and is applicable to all entities in which Duke Energy is involved with, including entities previously subject to existing accounting guidance for VIEs, as well as any QSPEs that exist as of the effective date. Early adoption of this revised accounting guidance is prohibited. Upon adoption of this revised accounting guidance, the accounting treatment and/or financial statement presentation of Duke Energy's accounts receivable securitization programs will be impacted as Cinergy Receivables will be consolidated by Duke Energy effective January 1, 2010. Duke Energy is currently evaluating the potential impact of the adoption of this revised accounting guidance on its other interests in VIEs and is unable to estimate at this time the impact of adoption on its consolidated results of operations, cash flows or financial position.

2. BUSINESS SEGMENTS

Duke Energy operates the following business segments, which are all considered reportable business segments: U.S. Franchised Electric and Gas, Commercial Power and International Energy. There is no aggregation of operating segments within Duke Energy's reportable business segments. Duke Energy's management believes these reportable business segments properly align the various operations of Duke Energy with how the chief operating decision maker views the business. Duke Energy's chief operating decision maker regularly reviews financial information about each of these reportable business segments in deciding how to allocate resources and evaluate performance.

U.S. Franchised Electric and Gas generates, transmits, distributes and sells electricity in central and western North Carolina, western South Carolina, central, north central and southern Indiana, and northern Kentucky. U.S. Franchised Electric and Gas also transmits, and distributes electricity in southwestern Ohio. Additionally, U.S. Franchised Electric and Gas transports and sells natural gas in southwestern Ohio and northern Kentucky. It conducts operations primarily through Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky. These electric and gas operations are subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (PSCSC), the PUCO, the Indiana Utility Regulatory Commission (IURC) and the Kentucky Public Service Commission (KPSC). The substantial majority of U.S. Franchised Electric and Gas' operations are regulated and, accordingly, these operations qualify for regulatory accounting treatment.

Commercial Power owns, operates and manages power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants as well as other contractual positions. Commercial Power's generation asset fleet consists of Duke Energy Ohio's regulated generation in Ohio and the five Midwestern gas-fired non-regulated generation assets that were a portion of the former Duke Energy North America (DENA) operations. Commercial Power's assets, excluding wind energy generation assets, comprise approximately 7,550 net MW of power generation primarily located in the Midwestern United States. The asset portfolio has a diversified fuel mix with base-load and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units. Effective January 2009, the generation asset output in Ohio is contracted under the ESP through December 31, 2011. As discussed further in Notes 1 and 4, beginning on December 17, 2008, Commercial Power reapplied regulatory accounting treatment to certain portions of its operations due to the passing of SB 221 and the approval of the ESP. Commercial Power also has a retail sales subsidiary, Duke Energy Retail Sales (DERS), which is certified by the PUCO as a Competitive Retail Electric Service (CRES) provider in Ohio. DERS serves retail electric customers in Southwest, West Central and Northern Ohio with generation and other energy services at competitive rates. During 2009, due to increased levels of customer switching as a result of the competitive markets in Ohio, DERS has focused on acquiring customers that had previously been served by Duke Energy Ohio under the ESP, as well as those previously served by other Ohio franchised utilities. Commercial Power also develops and implements customized energy solutions. Through Duke Energy Generation Services, Inc. and its affiliates (DEGS), Commercial Power develops, owns and operates electric generation for large energy consumers, municipalities, utilities and industrial facilities. DEGS currently manages 6,150 MW of power generation at 21 facilities throughout the U.S. In addition, DEGS engages in the development, construction and operation of wind energy projects. Currently, DEGS has approximately 735 net MW of wind energy generating capacity in commercial operation, approximately 250 MW of wind energy under construction and more than 5,000 MW of wind energy projects in development. DEGS is also developing transmission, solar and biomass projects.

International Energy principally operates and manages power generation facilities and engages in sales and marketing of electric power and natural gas outside the U.S. It conducts operations primarily through Duke Energy International, LLC and its affiliates and its activities principally target power generation in Latin America. Additionally, International Energy owns equity investments in National Methanol Company (NMC), located in Saudi Arabia, which is a leading regional producer of methanol and methyl tertiary butyl ether (MTBE), and Attiki Gas Supply S.A. (Attiki), which is a natural gas distributor located in Athens, Greece. See Note 12 for additional information related to the investment in Attiki subsequent to December 31, 2009.

The remainder of Duke Energy's operations is presented as Other. While it is not considered a business segment, Other primarily includes certain unallocated corporate costs, Bison Insurance Company Limited (Bison), Duke Energy's wholly-owned, captive insurance subsidiary, Duke Energy's effective 50% interest in the Crescent JV (Crescent) and DukeNet Communications, LLC (DukeNet) and related telecommunications. Additionally, Other includes Duke Energy Trading and Marketing, LLC (DETM), which is 40% owned by ExxonMobil and 60% owned by Duke Energy, and management is currently in the process of winding down. Unallocated corporate costs include certain costs not allocable to Duke Energy's reportable business segments, primarily governance costs, costs to achieve mergers and divestitures (such as the Cinergy merger and spin-off of Spectra) and costs associated with certain corporate severance programs. Bison's principal activities as a captive insurance entity include the insurance and reinsurance of various business risks and losses, such as property, business interruption and general liability of subsidiaries and affiliates of Duke Energy. On a limited basis, Bison also participates in reinsurance activities with certain third parties. Crescent, which develops and manages high-quality commercial, residential and multi-family real estate projects primarily in the Southeastern and Southwestern U.S, filed Chapter 11 petitions in a U.S. Bankruptcy Court in June 2009. As a result of recording its proportionate share of impairment charges recorded by Crescent during 2008, the carrying value of Duke Energy's investment balance in Crescent is zero and Duke Energy discontinued applying the equity method of accounting to its investment in Crescent in the third quarter of 2008 and has not recorded its proportionate share of any Crescent earnings or losses in subsequent periods. See Note 12 for additional information related to Crescent. DukeNet develops, owns and operates a fiber optic communications network, primarily in the Southeast U.S., serving wireless, local and long-distance communications companies, internet service providers and other businesses and organizations.

Duke Energy's reportable business segments offer different products and services or operate under different competitive environments and are managed separately. Accounting policies for Duke Energy's segments are the same as those described in Note 1. Management evaluates segment performance based on earnings before interest and taxes from continuing operations (excluding certain corporate governance costs), after deducting amounts attributable to noncontrolling interests related to those profits (EBIT). On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest, taxes and certain allocated governance costs, and is net of the expenses attributable to noncontrolling interests related to those profits. Segment EBIT includes transactions between reportable segments.

Cash, cash equivalents and short-term investments are managed centrally by Duke Energy, so the associated interest and dividend income on those balances, as well as realized and unrealized gains and losses from foreign currency remeasurement and transactions, are excluded from the segments' EBIT.

Business Segment Data[a]

(in millions)	Unaffiliated Revenues	Intersegment Revenues	Total Revenues	Segment EBIT/ Consolidated Income from Continuing Operations before Income Taxes	Depreciation and Amortization	Capital and Investment Expenditures and Acquisitions	Segment Assets[b]
Year Ended December 31, 2009							
U.S. Franchised Electric and Gas	$ 9,392	$ 41	$ 9,433	$2,321	$1,290	$3,560	$42,763
Commercial Power[c]	2,109	5	2,114	27	206	688	7,345
International Energy	1,158	—	1,158	365	81	128	4,067
Total reportable segments	12,659	46	12,705	2,713	1,577	4,376	54,175
Other	72	56	128	(251)	79	181	2,736
Eliminations and reclassifications	—	(102)	(102)	—	—	—	129
Interest expense	—	—	—	(751)	—	—	—
Interest income and other[d]	—	—	—	102	—	—	—
Add back of noncontrolling interest component of reportable segment and Other EBIT	—	—	—	18	—	—	—
Total consolidated	**$12,731**	**$ —**	**$12,731**	**$1,831**	**$1,656**	**$4,557**	**$57,040**
Year Ended December 31, 2008							
U.S. Franchised Electric and Gas	$10,130	$ 29	$10,159	$2,398	$1,326	$3,650	$39,556
Commercial Power	1,817	9	1,826	264	174	870	7,467
International Energy	1,185	—	1,185	411	84	161	3,309
Total reportable segments	13,132	38	13,170	3,073	1,584	4,681	50,332
Other[e]	75	59	134	(568)	86	241	2,605
Eliminations and reclassifications	—	(97)	(97)	—	—	—	140
Interest expense	—	—	—	(741)	—	—	—
Interest income and other[d]	—	—	—	117	—	—	—
Add back of noncontrolling interest component of reportable segment and Other EBIT	—	—	—	10	—	—	—
Total consolidated	$13,207	$ —	$13,207	$1,891	$1,670	$4,922	$53,077
Year Ended December 31, 2007							
U.S. Franchised Electric and Gas	$ 9,715	$ 25	$ 9,740	$2,305	$1,437	$2,613	$35,950
Commercial Power	1,870	11	1,881	278	169	442	6,826
International Energy	1,060	—	1,060	388	79	74	3,707
Total reportable segments	12,645	36	12,681	2,971	1,685	3,129	46,483
Other	75	92	167	(260)	61	153	3,176
Eliminations and reclassifications	—	(128)	(128)	—	—	—	27
Interest expense	—	—	—	(685)	—	—	—
Interest income and other[d]	—	—	—	201	—	—	—
Add back of noncontrolling interest component of reportable segment and Other EBIT	—	—	—	9	—	—	—
Total consolidated	$12,720	$ —	$12,720	$2,236	$1,746	$3,282	$49,686

(a) Segment results exclude results of entities classified as discontinued operations.
(b) Includes assets held for sale and assets of entities in discontinued operations. See Note 12 for description and carrying value of investments accounted for under the equity method of accounting within each segment.
(c) As discussed further in Note 11, during the year ended December 31, 2009, Commercial Power recorded impairment charges of approximately $413 million, which consists primarily of a goodwill impairment charge associated with its Midwest non-regulated generation assets.
(d) Other within interest income and other includes foreign currency transaction gains and losses and additional noncontrolling interest expense not allocated to the segment results.
(e) As discussed further in Note 12, Duke Energy recorded its proportionate share of impairment charges recorded by Crescent of approximately $238 million during the year ended December 31, 2008.

Geographic Data

(in millions)	U.S.	Latin America[a]	Consolidated
2009			
Consolidated revenues	$11,573	$1,158	$12,731
Consolidated long-lived assets	41,043	2,561	43,604
2008			
Consolidated revenues	$12,022	$1,185	$13,207
Consolidated long-lived assets	37,866	2,065	39,931
2007			
Consolidated revenues	$11,660	$1,060	$12,720
Consolidated long-lived assets	33,746	2,298	36,044

(a) Change in amounts of long-lived assets in Latin America is primarily due to foreign currency translation adjustments on property, plant and equipment and other long-lived asset balances.

3. ACQUISITIONS AND DISPOSITIONS OF BUSINESSES AND SALES OF OTHER ASSETS

Acquisitions.

Duke Energy consolidates assets and liabilities from acquisitions as of the purchase date, and includes earnings from acquisitions in consolidated earnings after the purchase date.

In June 2009, Duke Energy completed the purchase of the remaining approximate 24% noncontrolling interest in the Aguaytia Integrated Energy Project (Aguaytia), located in Peru, for approximately $28 million. Subsequent to this transaction, Duke Energy owns 100% of Aguaytia. As the carrying value of the noncontrolling interest was approximately $42 million at the date of acquisition, Duke Energy's consolidated equity increased approximately $14 million as a result of this transaction. Cash paid for acquiring this additional ownership interest is included in Distributions to noncontrolling interests within Net cash provided by (used in) financing activities on the Consolidated Statements of Cash Flows.

In June 2009, Duke Energy acquired North Allegheny Wind, LLC (North Allegheny) in Western Pennsylvania for approximately $124 million. The fair value of the net assets acquired were determined primarily using a discounted cash flow model as the output of North Allegheny is contracted for 23 1/2 years under a fixed price purchased power agreement. Substantially all of the fair value of the acquired net assets has been attributed to property, plant and equipment. There was no goodwill associated with this transaction. North Allegheny owns 70 MW of power generating assets that began commercially generating electricity in the third quarter of 2009.

On September 30, 2008, Duke Energy completed the purchase of a portion of Saluda River Electric Cooperative, Inc.'s (Saluda) ownership interest in the Catawba Nuclear Station. Under the terms of the agreement, Duke Energy paid approximately $150 million for the additional ownership interest in the Catawba Nuclear Station. Following the closing of the transaction, Duke Energy owns approximately 19% of the Catawba Nuclear Station. No goodwill was recorded as a result of this transaction. See Note 4 for discussion of the NCUC and the PSCSC approval of Duke Energy's petition requesting an accounting order to defer incremental costs incurred from the purchase of this additional ownership interest.

In September 2008, Duke Energy acquired Catamount Energy Corporation (Catamount), a leading wind power company located in Rutland, Vermont. This acquisition included over 300 MW of power generating assets, including 283 net MW in the Sweetwater wind power facility in West Texas, and 20 net MW of biomass-fueled cogeneration in New England and also included approximately 1,750 MW of wind assets with the potential for development in the U.S. and United Kingdom. This transaction resulted in a purchase price of approximately $245 million plus the assumption of approximately $80 million of debt. The purchase accounting entries consisted of approximately $190 million of equity method investments, approximately $117 million of intangible assets related to wind development rights, approximately $70 million of goodwill, none of which is deductible for tax purposes, and approximately $80 million of debt. See "dispositions" below for a discussion of the subsequent sale of two projects acquired as part of the Catamount transaction.

In May 2007, Duke Energy acquired the wind power development assets of Energy Investor Funds from Tierra Energy. The purchase included more than 1,000 MW of wind assets in various stages of development in the Western and Southwestern U.S. and supports Duke Energy's strategy to increase its investment in renewable energy. A significant portion of the purchase price was for intangible assets. Three of the development projects, totaling approximately 240 MW, are located in Texas and Wyoming. Two of these projects went into commercial operation during 2008, with the other project beginning commercial operation in 2009.

The pro forma results of operations for Duke Energy as if those acquisitions discussed above which closed prior to December 31, 2009 occurred as of the beginning of the periods presented do not materially differ from reported results.

Dispositions.

In the first quarter of 2009, Duke Energy completed the sale of two United Kingdom wind projects acquired in the Catamount acquisition. No gain or loss was recognized on these transactions. As these projects did not meet the definition of a disposal group as defined within the applicable accounting guidance, these projects were not reflected as held for sale on the Consolidated Balance Sheets prior to the completion of the sale.

On January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses. See Note 1 and Note 13 for additional information.

Other Asset Sales.

For the year ended December 31, 2009, the sale of other assets resulted in approximately $63 million in proceeds and net pre-tax gains of approximately $36 million, which is recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations. These gains primarily relate to sales of emission allowances by U.S. Franchised Electric and Gas and Commercial Power.

For the year ended December 31, 2008, the sale of other assets resulted in approximately $87 million in proceeds and net pre-tax gains of approximately $69 million, which is recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations. These gains primarily relate to Commercial Power's sales of emission allowances.

For the year ended December 31, 2007, the sale of other assets resulted in approximately $32 million in proceeds and net pre-tax losses of approximately $5 million, which is recorded in Gains (Losses) on Sales of Other Assets and Other, net, in the Consolidated Statements of Operations. These losses primarily relate to Commercial Power's sales of emission allowances that were written up to fair value in purchase accounting in connection with Duke Energy's merger with Cinergy in April 2006.

4. REGULATORY MATTERS

Regulatory Assets and Liabilities.

The substantial majority of U.S. Franchised Electric and Gas' operations and certain portions of Commercial Power's operations apply regulatory accounting treatment. Accordingly, these businesses record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See Note 1 for further information.

Duke Energy's Regulatory Assets and Liabilities:

(in millions)	As of December 31, 2009	2008	Recovery/Refund Period Ends[s]
Regulatory Assets[a]			
Net regulatory asset related to income taxes[c]	$ 557	$ 625	[o]
Accrued pension and post retirement[d]	1,295	1,261	[b]
ARO costs and NDTF assets[d]	901	1,016	2043
Regulatory transition charges[d]	73	138	2011
Gasification services agreement buyout costs[d]	145	175	2018
Deferred debt expense[c]	151	160	2039
Vacation accrual[e]	142	137	2010
Post-in-service carrying costs and deferred operating expense[c][d]	95	101	[o]
Under-recovery of fuel costs[f][u]	182	163	2011
Regional Transmission Organization (RTO) costs[h]	16	20	[g]
Hedge costs and other deferrals[h][r]	81	107	2011
Storm cost deferrals[d]	38	36	[b]
Forward contracts to purchase emission allowances[h]	2	33	2011
Allen Steam Station/Saluda River deferrals[h][t]	63	—	2014
Over-distribution of Bulk Power Marketing sharing[f]	30	—	2011
Other[h]	115	105	[b]
Total Regulatory Assets	$3,886	$4,077	
Regulatory Liabilities[a]			
Removal costs[c][i]	$2,277	$2,162	[q]
Nuclear property and liability reserves[c][k]	188	184	2043
Demand-side management costs[j][k]	156	134	[p]
Accrued pension and other post-retirement benefits[i]	91	—	[b]
Gas purchase costs[l]	29	14	2010
Over-recovery of fuel costs[m][j]	218	60	2011
Under-distribution of Bulk Power Marketing sharing[n]	13	23	2010
Commodity contract termination settlement[i]	30	—	2014
Other[i]	106	101	[b]
Total Regulatory Liabilities	$3,108	$2,678	

(a) All regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) Recovery/Refund period varies for these items with some currently unknown.
(c) Included in rate base.
(d) Included in Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets.
(e) Included in Other Current Assets on the Consolidated Balance Sheets.
(f) Included in Accounts Receivable and Other Assets on the Consolidated Balance Sheets.
(g) North Carolina portion of approximately $7 million to be recovered in rates through 2012. South Carolina portion of approximately $9 million to be recovered in retail rates through 2014.
(h) Included in Other Current Assets and Other Regulatory Assets and Deferred Debits on the Consolidated Balance Sheets.
(i) Included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.
(j) Duke Energy is required to pay interest on the outstanding balance.
(k) Included in Other Current Liabilities and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.
(l) Included in Accounts Payable on the Consolidated Balance Sheets.
(m) Included in Accounts Payable and Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.
(n) Included in Other Current Liabilities on the Consolidated Balance Sheets.
(o) Recovery is over the life of the associated asset.
(p) Incurred costs were deferred and are being recovered in rates. U.S. Franchised Electric and Gas is over-recovered for approximately $140 million of these costs in the South Carolina jurisdiction at December 31, 2009. South Carolina over-recovery will be refunded via a rate rider implemented February 2010 that is expected to return these funds over approximately three years, dependent on volume of sales in that jurisdiction.
(q) Liability is extinguished over the lives of the associated assets.
(r) Approximately $75 million and $95 million of the balance at December 31, 2009 and 2008, respectively, relates to mark-to-market deferrals associated with open native load hedge positions at Commercial Power.
(s) Represents the latest recovery period across all jurisdictions in which Duke Energy operates. Regulatory asset and liability balances may be collected or refunded sooner than the indicated date in certain jurisdictions.
(t) North Carolina has approved earning a return on the outstanding balance. South Carolina will not earn a return during the refund period.
(u) Approximately $88 million and an insignificant amount at December 31, 2009 and 2008, respectively, relates to under collections of Commercial Power's native load fuel costs.

Restrictions on the Ability of Certain Subsidiaries to Make Dividends, Advances and Loans to Duke Energy Corporation.

As a condition to the Duke Energy and Cinergy merger approval, the PUCO, the KPSC, the PSCSC, the IURC and the NCUC imposed conditions (the Merger Conditions) on the ability of Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Kentucky and Duke Energy Indiana to transfer funds to Duke Energy through loans or advances, as well as restricted amounts available to pay dividends to Duke Energy. Duke Energy's public utility subsidiaries may not transfer funds to the parent through intercompany loans or advances; however, certain subsidiaries may transfer funds to the parent by obtaining approval of the respective state regulatory commissions. Additionally, the Merger Conditions imposed the following restrictions on the ability of the public utility subsidiaries to pay cash dividends:

Duke Energy Carolinas. Under the Merger Conditions, Duke Energy Carolinas must limit cumulative distributions to Duke Energy Corporation subsequent to the merger to (i) the amount of retained earnings on the day prior to the closing of the merger, plus (ii) any future earnings recorded by Duke Energy Carolinas subsequent to the merger.

Duke Energy Ohio. Under the Merger Conditions, Duke Energy Ohio will not declare and pay dividends out of capital or unearned surplus without the prior authorization of the PUCO. In September 2009, the PUCO approved Duke Energy Ohio's request to pay dividends out of paid-in capital up to the amount of the pre-merger retained earnings and to maintain a minimum of 20% equity in its capital structure.

Duke Energy Kentucky. Under the Merger Conditions, Duke Energy Kentucky is required to pay dividends solely out of retained earnings and to maintain a minimum of 35% equity in its capital structure.

Duke Energy Indiana. Under the Merger Conditions, Duke Energy Indiana shall limit cumulative distributions paid subsequent to the Duke Energy-Cinergy merger to (i) the amount of retained earnings on the day prior to the closing of the merger plus (ii) any future earnings recorded by Duke Energy Indiana subsequent to the merger. In addition, Duke Energy Indiana will not declare and pay dividends out of capital or unearned surplus without prior authorization of the IURC.

Additionally, certain other subsidiaries of Duke Energy have restrictions on their ability to dividend, loan or advance funds to Duke Energy due to specific legal or regulatory restrictions, including, but not limited to, minimum working capital and tangible net worth requirements.

At December 31, 2009, Duke Energy's consolidated subsidiaries had restricted net assets of approximately $10.5 billion that may not be transferred to Duke Energy without appropriate approval based on the aforementioned merger conditions.

U.S. Franchised Electric and Gas.

Rate Related Information.

The NCUC, PSCSC, IURC and KPSC approve rates for retail electric and gas services within their states. The PUCO approves rates for retail gas and electric service within Ohio, except that non-regulated sellers of gas and electric generation also are allowed to operate in Ohio (see "Commercial Power" below). The FERC approves rates for electric sales to wholesale customers served under cost-based rates.

Duke Energy Carolinas North Carolina 2007 Rate Case.

On December 20, 2007, the NCUC issued its Order Approving Stipulation and Deciding Non-Settled Issues (Order), which required that Duke Energy Carolinas' test period for operating costs reflect an annualized level of the merger cost savings actually experienced in the test period. However, the NCUC recognized that its treatment of merger savings would not produce a fair result. Therefore, on February 18, 2008, the NCUC issued an order authorizing a 12-month increment rider, beginning January 2008, of approximately $80 million designed to provide a more equitable sharing of the actual merger savings achieved on an ongoing basis. Duke Energy Carolinas implemented the rate rider effective January 1, 2008 and terminated the rider effective January 1, 2009. The Order ultimately resulted in an overall average rate decrease of 5% in 2008, increasing to 7% upon expiration of this one-time rate rider.

Duke Energy Carolinas 2009 North Carolina Rate Case.

On June 2, 2009, Duke Energy Carolinas filed an Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina to increase its base rates. The Application was based upon a historical test year consisting of the 12 months ended December 31, 2008. On October 20, 2009, Duke Energy Carolinas entered into a settlement agreement with the North Carolina Public Staff. Two organizations representing industrial customers joined the settlement on October 22, 2009. The terms of the agreement include a base rate increase of $315 million (or approximately 8%) phased in primarily over a two-year period beginning January 1, 2010. In order to mitigate the impact of the increase on customers, the agreement provides for (i) a one-year delay in the collection of financing costs related to the Cliffside modernization project until January 1, 2011; and (ii) the accelerated return of certain regulatory liabilities to customers which lower the total impact to customer bills to an increase of approximately 7% in the near-term. The proposed settlement included a 10.7% return on equity and a capital structure of 52.5% equity and 47.5% long-term debt. Additionally, Duke Energy Carolinas agreed not to file another rate case before 2011 with any changes to rates taking effect no sooner than 2012. The NCUC approved the settlement agreement in full by order dated December 7, 2009. The new rates were effective and implemented on January 1, 2010.

Duke Energy Carolinas 2009 South Carolina Rate Case.

On July 27, 2009, Duke Energy Carolinas filed its Application for Authority to Increase and Adjust Rates and Charges for an increase in rates and charges in South Carolina including approval of a charge to customer bills to pay for Duke Energy Carolinas' new energy efficiency efforts. Parties to the proceeding include the South Carolina Office of Regulatory Staff (ORS), the South Carolina Energy Users Committee (SCEUC), and the South Carolina Green Party. Duke Energy Carolinas, ORS, and SCEUC filed a settlement agreement on November 24, 2009, recommending, (i) a $74 million increase in base rates, (ii) an allowed return on equity of 11% with rates set at a return on equity of 10.7% and capital structure of 53% equity, and (iii) various riders, including one that provides for the return of DSM charges previously collected from customers over three years, and another that provides for a storm reserve provision allowing Duke Energy Carolinas to collect $5 million annually (up to a maximum funding level of $50 million accumulating in reserves) to be used against large storm costs in any particular period. On January 20, 2010, the PSCSC approved the settlement agreement in full, including the cost recovery mechanism for the energy efficiency effort. The new rates were effective February 1, 2010.

Duke Energy Ohio Electric Rate Filings.

New legislation (SB 221) codifies the PUCO's authority to approve an electric utility's standard generation service offer through an ESP, which would allow for pricing structures similar to those under the historic RSP. Electric utilities are required to file an ESP and may also file an application for a MRO at the same time. The MRO is a price determined through a competitive bidding process. SB 221 provides for the PUCO to approve non-bypassable charges for new generation, including construction work-in-process from the outset of construction, as part of an ESP. The new law grants the PUCO discretion to approve single issue rate adjustments to distribution and transmission rates and establishes new alternative energy resources (including renewable energy) portfolio standards, such that a utility's portfolio must consist of at least 25% of these resources by 2025. SB 221 also provides a separate requirement for energy efficiency, which must reduce a utility's load by 22% before 2025. A utility's earnings under the ESP are subject to an annual earnings test and the PUCO must order a refund if it finds that the utility's earnings significantly exceed the earnings of benchmark companies with similar business and financial risks. The earnings test acts as a cap to the ESP price. SB 221 also limits the ability of a utility to transfer its designated generating assets to an exempt wholesale generator (EWG) absent PUCO approval. On July 31, 2008, Duke Energy Ohio filed an ESP to be effective January 1, 2009. On December 17, 2008, the PUCO issued its finding and order adopting a modified Stipulation with respect to Duke Energy Ohio's ESP filing. The PUCO agreed to Duke Energy Ohio's request for a net increase in base generation revenues, before impacts of customer switching, of $36 million, $74 million and $98 million in 2009, 2010 and 2011, respectively, including the termination of the residential and non-residential Regulatory Transition Charge, the recovery of expenditures incurred to deploy the SmartGrid infrastructure and the implementation of save-a-watt. The Stipulation also allowed Duke Energy Ohio to defer up to $50 million of certain operation and maintenance costs incurred at the W.C. Beckjord generating station for its continued operation and to amortize those costs over the three-year ESP period. The PUCO modified the Stipulation to permit certain non-residential customers to opt out of utility-sponsored energy efficiency initiatives and to allow residential governmental aggregation customers who leave Duke Energy Ohio's system to avoid some charges.

As discussed further below within "Commercial Power" and in Note 1, as a result of the approval of the ESP, effective December 17, 2008, Commercial Power reapplied regulatory accounting to certain portions of its operations.

Duke Energy Ohio Gas Rate Case.

In July 2007, Duke Energy Ohio filed an application with the PUCO for an increase in its base rates for gas service. The application also requested approval to continue tracker recovery of costs associated with the accelerated gas main replacement program and an acceleration of the riser replacement program. On February 28, 2008, Duke Energy Ohio reached a settlement agreement with the PUCO Staff and all of the intervening parties on its request for an increase in natural gas base rates. The settlement called for an annual revenue increase of approximately $18 million in base revenue, or 3% over current revenue, permitted continued recovery of costs through 2018 for Duke Energy Ohio's accelerated gas main and riser replacement program and permitted recovery of carrying costs on gas stored underground via its monthly gas cost adjustment filing. The settlement did not resolve a proposed rate design for residential customers, which involved moving more of the fixed charges of providing gas service, such as capital investment in pipes and regulating equipment, billing and meter reading, from the per unit charges to the monthly charge. On May 28, 2008, the PUCO approved the settlement in its entirety and Duke Energy Ohio's proposed modified straight fixed-variable rate design.

Duke Energy Ohio Electric Distribution Rate Case.

On June 25, 2008, Duke Energy Ohio filed notice with the PUCO that it would seek a rate increase for electric delivery service to be effective in the second quarter of 2009. On December 22, 2008, Duke Energy Ohio filed an application requesting deferral of approximately $31 million related to damage to its distribution system from a September 14, 2008 windstorm, which was granted by the PUCO. Accordingly, a $31 million regulatory asset was recorded in 2008. On March 31, 2009, Duke Energy Ohio and Parties to the case filed a Stipulation and Recommendation which settles all issues in the case. The Stipulation provided for a revenue increase of $55 million, or approximately a 2.9% overall increase.

The Parties also agreed that Duke Energy Ohio will recover any approved costs associated with the September 14, 2008 wind storm restoration through a separate rider recovery mechanism. Duke Energy Ohio agreed to file a separate application to set the rider and the PUCO will review the request and determine the appropriate amount of storm costs that should be recovered. The Stipulation includes, among other things, a weatherization and energy efficiency program, and recovery of distribution-related bad debt expenses through a rider mechanism. The Stipulation was approved in its entirety by the PUCO on July 8, 2009 and rates were effective July 13, 2009. On January 26, 2010, the Ohio Supreme Court affirmed the PUCO's decision.

Duke Energy Kentucky Gas Rate Cases.

In 2002, the KPSC approved Duke Energy Kentucky's gas base rate case which included, among other things, recovery of costs associated with an accelerated gas main replacement program. The approval authorized a tracking mechanism to recover certain costs including depreciation and a rate of return on the program's capital expenditures. The Kentucky Attorney General appealed to the Franklin Circuit Court the KPSC's approval of the tracking mechanism as well as the KPSC's subsequent approval of annual rate adjustments under this tracking mechanism. In 2005, both Duke Energy Kentucky and the KPSC requested that the court dismiss these cases.

In February 2005, Duke Energy Kentucky filed a gas base rate case with the KPSC requesting approval to continue the tracking mechanism and for a $14 million annual increase in base rates. A portion of the increase was attributable to recovery of the current cost of the accelerated gas main replacement program in base rates. In June 2005, the Kentucky General Assembly enacted Kentucky Revised Statute 278.509 (KRS 278.509), which specifically authorizes the KPSC to approve tracker recovery for utilities' gas main replacement programs. In December 2005, the KPSC approved an annual rate increase and re-approved the tracking mechanism through 2011. In February 2006, the Kentucky Attorney General appealed the KPSC's order to the Franklin Circuit Court, claiming that the order improperly allows Duke Energy Kentucky to increase its rates for gas main replacement costs in between general rate cases, and also claiming that the order improperly allows Duke Energy Kentucky to earn a return on investment for the costs recovered under the tracking mechanism which permits Duke Energy Kentucky to recover its gas main replacement costs.

In August 2007, the Franklin Circuit Court consolidated all the pending appeals and ruled that the KPSC lacks legal authority to approve the gas main replacement tracking mechanism, which was approved prior to the enactment of KRS 278.509 in 2005. To date, Duke Energy Kentucky has collected approximately $9 million in annual rate adjustments under the tracking mechanism. Per the KPSC order, Duke Energy Kentucky collected these revenues subject to refund pending the final outcome of this litigation. Duke Energy Kentucky and the KPSC have requested that the Kentucky Court of Appeals grant a rehearing of its decision. On February 5, 2009, the Kentucky Court of Appeals denied the rehearing requests of both Duke Energy Kentucky and the KPSC. Duke Energy Kentucky filed a motion for discretionary review to the Kentucky Supreme Court on or about March 6, 2009. The Kentucky Supreme Court has accepted discretionary review of this case and merit briefs were filed on October 19, 2009. Duke Energy Kentucky filed its reply brief on January 4, 2010.

On July 1, 2009, Duke Energy Kentucky filed its application for an approximate $18 million increase in base natural gas rates. Duke Energy Kentucky also proposed to implement a modified straight fixed-variable rate design for residential customers, which involves moving more of the fixed charges of providing gas service, such as capital investment in pipes and regulating equipment, billing and meter reading, from the volumetric charges to the fixed monthly charge. On November 19, 2009, Duke Energy Kentucky and the Kentucky Attorney General jointly filed a Stipulation and Recommendation reflecting their settlement of the gas rate case. The Stipulation and Recommendation reflects a revenue increase of $13 million, which reflected a10.375% Return on Equity. Duke Energy Kentucky agreed to withdraw its request for a straight fixed-variable rate design and to forego filing another gas rate case in the eighteen months following approval of the Stipulation and Recommendation. The KPSC issued an order approving the Stipulation and Recommendation on December 29, 2009. New rates went into effect January 4, 2010.

Duke Energy Carolinas Energy Efficiency.

On May 7, 2007, Duke Energy Carolinas filed its save-a-watt application with the NCUC. The save-a-watt proposal is based on the avoided cost of generation not needed resulting from any successful Duke Energy Carolinas energy efficiency programs. On February 26, 2009, the NCUC issued an order (i) approving Duke Energy Carolinas' energy efficiency programs; (ii) requesting additional information on Duke Energy Carolinas' returns under eight different compensation scenarios; and (iii) authorizing Duke Energy Carolinas to implement its rate rider pending approval of a final compensation mechanism by the NCUC. Duke Energy Carolinas filed the additional information requested by the NCUC on March 31, 2009. On June 12, 2009, Duke Energy Carolinas filed with the NCUC a settlement agreement between Duke Energy Carolinas and the Public Staff and several environmental intervenors. A hearing on the settlement was held on August 19, 2009. A Notice of Decision approving the settlement with modifications was issued on December 14, 2009. Duke Energy Carolinas began offering energy conservation programs to North Carolina retail customers and billing a conservation-only rider on June 1, 2009. On February 10, 2010, the NCUC approved the order in full.

In mid-October 2009, Duke Energy Carolinas began offering demand response programs in North Carolina. On January 1, 2010, Duke Energy Carolinas began to bill the full Rider Energy Efficiency approved by the NCUC in its December 14, 2009 Notice of Decision.

On May 6, 2009, the PSCSC approved Duke Energy Carolinas' request for (i) approval of conservation and demand response programs; (ii) cancellation of certain existing demand response programs; (iii) deferral of the costs incurred to develop and implement the energy efficiency programs from June 1, 2009 until the date these costs are reflected in electric rates; and (iv) assurance that Duke Energy Carolinas may true-up incentives for costs deferred pursuant to the petition in accordance with the PSCSC order on the appropriate compensation mechanism in Duke Energy Carolinas' 2009 general rate proceeding. Duke Energy Carolinas began offering demand response and conservation programs to South Carolina retail customers effective June 1, 2009. As described above, on January 20, 2010, the PSCSC approved Duke Energy Carolinas' cost recovery mechanism for energy efficiency. The new rates were effective February 1, 2010.

The save-a-watt programs and compensation approach in both North Carolina and South Carolina are approved through December 31, 2013.

Duke Energy Ohio Energy Efficiency.

Duke Energy Ohio filed the save-a-watt Energy Efficiency Plan as part of its ESP filed with the PUCO, which was approved by the PUCO on December 17, 2008, as discussed above, including allowing for the implementation of a new save-a-watt energy efficiency compensation model. However, the PUCO determined that certain non-residential customers may opt out of Duke Energy Ohio's energy efficiency initiative. Applications for rehearing of this issue were denied by the PUCO and no further appeals of this issue have been taken. The save-a-watt programs and compensation approach in Ohio are approved through December 31, 2011.

Duke Energy Indiana Energy Efficiency.

In October 2007, Duke Energy Indiana filed its petition with the IURC requesting approval of an alternative regulatory plan to increase its energy efficiency efforts in the state. Duke Energy Indiana seeks approval of a plan that will be available to all customer groups and will compensate Duke Energy Indiana for verified reductions in energy usage. Under the plan, customers would pay for energy efficiency programs through an energy efficiency rider that would be included in their power bill and adjusted annually through a proceeding before the IURC. The energy efficiency rider proposal is based on the save-a-watt compensation model of avoided cost of generation. A number of parties have intervened in the proceeding. Duke Energy Indiana has reached a settlement with all intervenors except one, the Citizens Action Coalition of Indiana, Inc. (CAC), and has filed such settlement agreement with the IURC. An evidentiary hearing with the IURC was held on February 27, 2009 and March 2, 2009. On February 10, 2010, the IURC approved the request. On December 9, 2009, the IURC issued an order concerning energy efficiency efforts within the state of Indiana wherein it required utilities, including Duke Energy Indiana, to promote a certain core set of energy efficiency programs through the use of a third party administrator that contracts directly with the utilities. The order also required energy usage reduction targets for the utilities, starting with 0.3% of sales in 2010 and increasing to 2% of sales in 2019. On February 10, 2010, the IURC issued an order approving the settlement with the OUCC with some modifications. The IURC approved Duke Energy Indiana's proposed programs and allowed for the save-a-watt model incentives for Core Plus programs. The IURC also rejected a settlement agreement that allowed large industrial and commercial customers to opt out of utility sponsored energy efficiency, finding that initially energy efficiency programs should be available to all customer classes.

Duke Energy Kentucky Energy Efficiency.

On November 15, 2007, Duke Energy Kentucky filed its annual application to continue existing energy efficiency programs, consisting of nine residential and two commercial and industrial programs, and to true-up its gas and electric tracking mechanism for recovery of lost revenues, program costs and shared savings. On February 11, 2008, Duke Energy Kentucky filed a motion to amend its energy efficiency programs. On December 1, 2008, Duke Energy Kentucky filed an application for a save-a-watt Energy Efficiency Plan. The application seeks a new energy efficiency recovery mechanism similar to what was proposed in Ohio. On January 27, 2010, Duke Energy Kentucky withdrew the application to implement save-a-watt and plans to file a revised portfolio in the future.

Duke Energy Carolinas Renewable Resources.

On June 6, 2008, Duke Energy Carolinas filed an application with the NCUC seeking approval to implement a solar photovoltaic distributed generation program (Program). Duke Energy Carolinas proposed to invest $100 million over two years to install a total of 20 MW of electricity generating solar panels on multiple North Carolina sites including homes, schools, stores and factories. The Program will help Duke Energy Carolinas meet the requirement of North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS). It will also enable Duke Energy Carolinas to evaluate the role of distributed generation on Duke Energy Carolinas' electrical system and gain experience in owning and operating renewable energy resources. Because the Program involves the construction of electric generating facilities, Duke Energy Carolinas required a Certificate of Public Convenience and Necessity (CPCN) from the NCUC. The REPS statute provides for the recovery of costs Duke Energy Carolinas incurs to comply with its requirements, principally through an annual rate rider.

In response to concerns raised by the Public Staff and various solar energy groups, Duke Energy Carolinas agreed to reduce the size of the Program to invest $50 million to install up to 10 MW of solar photovoltaic capacity. On December 31, 2008, the NCUC issued its Order Granting CPCN Subject to Conditions. The conditions (i) reduce the program size from 20 MW to 10 MW (as previously agreed upon by Duke Energy Carolinas); and (ii) limit program costs recoverable through the REPS rider to program costs equivalent to the cost of the third place bid in Duke Energy Carolinas' 2007 request for proposal for renewable energy. The Order left open the opportunity to recover the excess costs through other recovery mechanisms. Based upon the revised size and availability of state and federal tax credits, Duke Energy Carolinas estimates the limited amount of program costs recoverable through the REPS rider will result in a monthly charge of approximately $0.05 for residential customers.

On May 6, 2009, in response to Duke Energy Carolinas' request for reconsideration, the NCUC issued an Order allowing Duke Energy Carolinas to proceed with the Program and allowed Duke Energy Carolinas to recover all costs incurred in executing the Program through a combination of the REPS rider and base rates, subject to the NCUC's review of the reasonableness and prudence of Duke Energy Carolinas' execution of the Program. However, the NCUC declined to remove the limitation on costs recoverable through the REPS rider.

Duke Energy Carolinas Deferral of Costs.

On February 4, 2009, Duke Energy Carolinas filed petitions with the NCUC and the PSCSC requesting an accounting order to defer the incremental costs incurred from the September 2008 purchase of an additional ownership interest in the Catawba Nuclear Station and certain post-in-service costs that are being or will be incurred in connection with the addition of the Allen Steam Station flue gas desulfurization equipment related to environmental compliance scheduled to go into service in the spring of 2009. The costs Duke Energy Carolinas sought to defer are the incremental costs that are being incurred or will be incurred from the date these assets are placed in service to the date Duke Energy Carolinas is authorized to begin reflecting in rates the recovery of such costs on an ongoing basis. On February 25, 2009, and March 31, 2009, the PSCSC and NCUC, respectively, approved the deferral of these costs. Duke Energy Carolinas began deferring costs in the first quarter 2009. These costs are being recovered in the new rates effective January 1, 2010 for North Carolina, and effective February 1, 2010, for South Carolina.

Duke Energy Carolinas Broad River Energy Center.

On August 25, 2007, Duke Energy Carolinas experienced a disturbance on its bulk electric system which initiated at the Broad River Energy Center, a generating station owned and operated by a third party. The disturbance resulted in the tripping of six Duke Energy Carolinas generating units and the temporary opening of five 230 kilovolt (KV) transmission lines. The event resulted in no loss of load. In September 2008 the FERC initiated a preliminary, non-public investigation to determine if there were any potential violations by Duke Energy Carolinas of the North American Electric Reliability Council Reliability Standards. This investigation was coordinated with an ongoing Compliance Violation Investigation conducted by SERC Reliability Corporation. On March 5, 2009, FERC presented its preliminary findings about the event to Duke Energy Carolinas and solicited Duke Energy Carolinas' responsive views about the event and the findings. On March 27, 2009, Duke Energy Carolinas conveyed its responsive views to FERC Staff. This investigation could result in penalties being assessed.

Capital Expansion Projects.

Overview.

U.S. Franchised Electric and Gas is engaged in planning efforts to meet projected load growth in its service territories. Capacity additions may include new nuclear, integrated gasification combined cycle (IGCC), coal facilities or gas-fired generation units. Because of the long lead times required to develop such assets, U.S. Franchised Electric and Gas is taking steps now to ensure those options are available.

William States Lee III Nuclear Station.

On December 12, 2007, Duke Energy Carolinas filed an application with the Nuclear Regulatory Commission (NRC), which has been docketed for review, for a combined Construction and Operating License (COL) for two Westinghouse AP1000 (advanced passive) reactors for the proposed William States Lee III Nuclear Station at a site in Cherokee County, South Carolina. Each reactor is capable of producing approximately 1,117 MW. Submitting the COL application does not commit Duke Energy Carolinas to build nuclear units. On December 7, 2007, Duke Energy Carolinas filed applications with the NCUC and the PSCSC for approval of Duke Energy Carolinas' decision to incur development costs associated with the proposed William States Lee III Nuclear Station. The NCUC had previously approved Duke Energy's decision to incur the North Carolina allocable share of up to $125 million in development costs through 2007. The 2007 requests cover a total of up to $230 million in development costs through 2009, which is comprised of $70 million incurred through December 31, 2007 plus an additional $160 million of anticipated costs in 2008 and 2009. The PSCSC approved Duke Energy Carolinas' William States Lee III Nuclear project development cost application on June 9, 2008, and the NCUC issued its approval order on June 11, 2008. On July 24, 2008, environmental intervenors filed motions to rescind or amend the approval orders issued by the NCUC and the PSCSC, and Duke Energy Carolinas subsequently filed responses in opposition to the motions. On August 13 and August 25, 2008, the PSCSC and NCUC, respectively, denied the environmental intervenor motion. The NRC review of the COL application continues and the estimated receipt of the COL is in mid 2013. Duke Energy Carolinas filed with the Department of Energy (DOE) for a federal loan guarantee, which has the potential to significantly lower financing costs associated with the proposed William States Lee III Nuclear Station; however, it was not among the four projects selected by the DOE for the final phase of due diligence for the federal loan guarantee program. The project could be selected in the future if the program funding is expanded or if any of the current finalists drop out of the program.

South Carolina passed new energy legislation (S 431) which became effective May 3, 2007. The legislation includes provisions to provide assurance of cost recovery related to a utility's incurrence of project development costs associated with nuclear baseload generation, cost recovery assurance for construction costs associated with nuclear or coal baseload generation, and the ability to recover financing costs for new nuclear baseload generation in rates during construction through a rider. The North Carolina General Assembly also passed comprehensive energy legislation North Carolina Senate Bill 3 (SB 3) in July 2007 that was signed into law by the Governor on August 20, 2007. Like the South Carolina legislation, the North Carolina legislation provides cost recovery assurance, subject to prudency review, for nuclear project development costs as well as baseload generation construction costs. A utility may include financing costs related to construction work in progress for baseload plants in a rate case.

Cliffside Unit 6.

On June 2, 2006, Duke Energy Carolinas filed an application with the NCUC for a CPCN to construct two 800 MW state of the art coal generation units at its existing Cliffside Steam Station in North Carolina. On March 21, 2007, the NCUC issued an Order allowing Duke Energy Carolinas to build one 800 MW unit. On February 20, 2008, Duke Energy Carolinas entered into an amended and restated engineering, procurement, construction and commissioning services agreement, valued at approximately $1.3 billion, with an affiliate of The Shaw Group, Inc., of which approximately $950 million relates to participation in the construction of Cliffside Unit 6, with the remainder related to a flue gas desulfurization system on an existing unit at Cliffside. On February 27, 2009, Duke Energy Carolinas filed its latest updated cost estimate of $1.8 billion (excluding up to approximately $0.6 billion of AFUDC) for the approved new Cliffside Unit 6. Duke Energy Carolinas believes that the overall cost of Cliffside Unit 6 will be reduced by approximately $125 million in federal advanced clean coal tax credits, as discussed further below.

On January 29, 2008, the North Carolina Department of Environment and Natural Resources (DENR) issued a final air permit for the new Cliffside Unit 6 and on-site construction has begun. In March 2008, four contested case petitions, which have since been consolidated, were filed appealing the final air permit. On May 12, 2009, the Administrative Law Judge issued rulings favorable to DENR and Duke Energy, dismissing several of petitioners' claims and granting summary judgment against petitioners on other claims, resulting in the dismissal of two petitions and leaving two for hearing. A hearing on remaining claims is scheduled for June 2010. See Note 16 for a discussion of a lawsuit filed by the Southern Alliance for Clean Energy, Environmental Defense Fund, National Parks Conservation Association, Natural Resources Defenses Council, and Sierra Club (collectively referred to as Citizen Groups) related to the construction of Cliffside Unit 6.

On October 14, 2008, Duke Energy Carolinas submitted revised hazardous air pollutant (HAPs) emissions determination documentation including revised emission source information to the Division of Air Quality (DAQ) indicating that no maximum achievable control technology (MACT) or MACT-like requirements apply since Cliffside Unit 6 has been demonstrated to be a minor source of HAPs.

After issuing a draft permit and holding public hearings on that draft permit in January 2009, the DAQ issued the revised permit on March 13, 2009, finding that Cliffside Unit 6 is a minor source of HAPs and imposing operating conditions to assure that emissions stay below the major source threshold. In May 2009, four contested case petitions were filed appealing the March 13, 2009 final air permit. These four cases have been consolidated with each other and with the four consolidated cases filed in 2008, resulting in the dismissal of two of the four cases. The same schedule will govern these cases with a hearing scheduled for June 2010.

Dan River and Buck Combined Cycle Facilities.

On June 29, 2007, Duke Energy Carolinas filed with the NCUC preliminary CPCN information to construct a 620 MW combined cycle natural gas-fired generating facility at its existing Dan River Steam Station, as well as updated preliminary CPCN information to construct a 620 MW combined cycle natural gas-fired generating facility at its existing Buck Steam Station. On December 14, 2007, Duke Energy Carolinas filed CPCN applications for the two combined cycle facilities. The NCUC consolidated its consideration of the two CPCN applications and held an evidentiary hearing on the applications on March 11, 2008. The NCUC issued its order approving the CPCN applications for the Buck and Dan River combined cycle projects on June 5, 2008. On May 5, 2008, Duke Energy Carolinas entered into an engineering, construction and commissioning services agreement for the Buck combined cycle project, valued at approximately $275 million, with Shaw North Carolina, Inc. On November 5, 2008, Duke Energy Carolinas notified the NCUC that since the issuance of the CPCN Order, recent economic factors have caused increased uncertainty with regard to forecasted load and near-term capital expenditures, resulting in a modification of the construction schedule. On September 1, 2009, Duke Energy Carolinas filed with the NCUC further information clarifying the construction schedule for the two projects. Under the revised schedule, the Buck Project is expected to begin operation in combined cycle mode by the end of 2011, but without a phased-in simple cycle commercial operation. The Dan River Project is expected to begin operation in combined cycle mode by the end of 2012, also without a phased-in simple cycle commercial operation. On December 21, 2009, Duke Energy Carolinas entered into a First Amended and Restated engineering, construction and commissioning services agreement with Shaw North Carolina, Inc. for $322 million which reflects the revised schedule. Based on the most updated cost estimates, total costs (including AFUDC) for the Buck and Dan River projects are approximately $660 million and $710 million, respectively.

On October 15, 2008, the DAQ issued a final air permit authorizing construction of the Buck combined cycle natural gas-fired generating units, and on August 24, 2009, the DAQ issued a final air permit authorizing construction of the Dan River combined cycle natural gas-fired generation units.

Edwardsport Integrated Gasification Combined Cycle (IGCC) Plant.

On September 7, 2006, Duke Energy Indiana and Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana (Vectren) filed a joint petition with the IURC seeking a CPCN for the construction of a 630 MW IGCC power plant at Duke Energy Indiana's Edwardsport Generating Station in Knox County, Indiana. The facility was initially estimated to cost approximately $2 billion (including approximately $120 million of AFUDC). In August 2007, Vectren formally withdrew its participation in the IGCC plant and a hearing was conducted on the CPCN petition based on Duke Energy Indiana owning 100% of the project. On November 20, 2007, the IURC issued an order granting Duke Energy Indiana a CPCN for the proposed IGCC project, approved the cost estimate of $1.985 billion and approved the timely recovery of costs related to the project. On January 25, 2008, Duke Energy Indiana received the final air permit from the Indiana Department of Environmental Management. The Citizens Action Coalition of Indiana, Inc., Sierra Club, Inc., Save the Valley, Inc., and Valley Watch, Inc., all intervenors in the CPCN proceeding, have appealed the air permit.

On May 1, 2008, Duke Energy Indiana filed its first semi-annual IGCC Rider and ongoing review proceeding with the IURC as required under the CPCN Order issued by the IURC. In its filing, Duke Energy Indiana requested approval of a new cost estimate for the IGCC Project of $2.35 billion (including approximately $125 million of AFUDC) and for approval of plans to study carbon capture as required by the IURC's CPCN Order. On January 7, 2009, the IURC approved Duke Energy Indiana's request, including the new cost estimate of $2.35 billion, and cost recovery associated with a study on carbon capture. Duke Energy Indiana was required to file its plans for studying carbon storage related to the project within 60 days of the order. On November 3, 2008 and May 1, 2009, Duke Energy Indiana filed its second and third semi-annual IGCC riders, respectively, both of which were approved by the IURC in full.

On November 24, 2009, Duke Energy Indiana filed a petition for its fourth semi-annual IGCC rider and ongoing review proceeding with the IURC. Duke Energy has experienced design modifications and scope growth above what was anticipated from the preliminary engineering design, adding capital costs to the IGCC project. Duke Energy Indiana forecasted that the additional capital cost items would use the remaining contingency and escalation amounts in the current $2.35 billion cost estimate and add approximately $150 million, or about 6.4% to the total IGCC Project cost estimate, excluding the impact associated with the need to add more contingency. Duke Energy Indiana did not request approval of an increased cost estimate in the fourth semi-annual update proceeding; rather, Duke Energy Indiana requested, and the IURC approved, a subdocket proceeding in which Duke Energy will present additional evidence regarding an updated estimated cost for the IGCC project and in which a more comprehensive review of the IGCC project could occur. The evidentiary hearing for the fourth semi-annual update proceeding is scheduled for April 6, 2010. In the cost estimate subdocket proceeding, Duke Energy Indiana will be filing a new cost estimate for the IGCC project on April 7, 2010, with its case-in-chief testimony, and a hearing is scheduled to begin August 10, 2010. Duke Energy Indiana continues to work with its vendors to update and refine the forecasted increased cost to complete the Edwardsport IGCC project, and currently anticipates that the total cost increase it submits in the cost estimate subdocket proceeding will be significantly higher than the $150 million previously identified.

Duke Energy Indiana filed a petition with the IURC requesting approval of its plans for studying carbon storage, sequestration and/or enhanced oil recovery for the carbon dioxide (CO_2) from the Edwardsport IGCC facility on March 6, 2009. On July 7, 2009, Duke Energy Indiana filed its case-in-chief testimony requesting approval for cost recovery of a $121 million site assessment and characterization plan for CO_2 sequestration options including deep saline sequestration, depleted oil and gas sequestration and enhanced oil recovery for the CO_2 from the Edwardsport IGCC facility. The OUCC filed testimony supportive of the continuing study of carbon storage, but recommended that Duke Energy Indiana break its plan into phases, recommending approval of only approximately $33 million in expenditures at this time and deferral of expenditures rather than cost recovery through a tracking mechanism as proposed by Duke Energy Indiana. Intervenor CAC recommended against approval of the carbon storage plan stating customers should not be required to pay for research and development costs. Duke Energy Indiana's rebuttal testimony was filed October 30, 2009, wherein it amended its request to seek deferral of approximately $42 million to cover the carbon storage site assessment and characterization activities scheduled to occur through approximately the end of 2010, with further required study expenditures subject to future IURC proceedings. An evidentiary hearing was held on November 9, 2009, and an order is expected in the first half of 2010.

Under the Edwardsport IGCC CPCN order and statutory provisions, Duke Energy Indiana is entitled to recover the costs reasonably incurred in reliance on the CPCN Order. In December 2008, Duke Energy Indiana entered into a $200 million engineering, procurement and construction management agreement with Bechtel Power Corporation and construction is underway.

Federal Advanced Clean Coal Tax Credits.

Duke Energy has been awarded approximately $125 million of federal advanced clean coal tax credits associated with its construction of Cliffside Unit 6 and approximately $134 million of federal advanced clean coal tax credits associated with its construction of the Edwardsport IGCC plant. In March, 2008, two environmental groups, Appalachian Voices and the Canary Coalition, filed suit against the Federal government challenging the tax credits awarded to incentivize certain clean coal projects. Although Duke Energy was not a party to the case, the allegations center on the tax incentives provided for Duke Energy's Cliffside and Edwardsport project. The initial complaint alleged a failure to comply with the National Environmental Policy Act. The first amended complaint, filed in August 2008, added an Endangered Species Act claim and also sought declaratory and injunctive relief against the DOE and the U.S. Department of the Treasury. In November 2008, the District Court dismissed the case. On September 23, 2009, the District Court issued an order granting plaintiffs' motion to amend their complaint and denying, as moot, the motion for reconsideration. Plaintiffs have filed their second amended complaint. The Federal government has moved to dismiss the second amended complaint; the motion is pending.

Other U.S. Franchised Electric and Gas Matters.

Duke Energy Carolinas City of Orangeburg, South Carolina Wholesale Sales.

On June 28, 2008, Duke Energy Carolinas filed notice with the NCUC that it intended to sell electricity to the City of Orangeburg, South Carolina (City of Orangeburg), a wholesale customer, at native load priority. Duke Energy Carolinas and the City of Orangeburg also filed a joint petition asking the NCUC to declare that the City of Orangeburg contract and all future Duke Energy Carolinas native load priority wholesale contracts will be treated for ratemaking and reporting purposes in the same manner as such existing wholesale contracts (i.e., revenues from those contracts will be allocated to wholesale jurisdiction and costs will be allocated to wholesale jurisdiction based on system average costs). On March 30, 2009, the NCUC issued its Order in which it concluded that Duke Energy Carolinas can proceed with the City of Orangeburg contract at its own risk; however, Duke Energy Carolinas cannot treat the City of Orangeburg's load as Duke Energy Carolinas' native load for rate setting purposes. Further, the NCUC concluded that based on the evidence presented, a future Commission should allocate costs based upon incremental costs in any future ratemaking case. The NCUC distinguished the City of Orangeburg from wholesale customers that have been historically served by Duke Energy Carolinas because the City of Orangeburg has not shared in the costs of Duke Energy Carolinas' existing system. Due to the NCUC ruling, Duke Energy Carolinas terminated the system average contract with the City of Orangeburg in April 2009 per the allowed contractual provisions. The City of Orangeburg then terminated its contingency contract with Duke Energy Carolinas at incremental pricing and informed Duke Energy Carolinas that it would take service from South Carolina Electric and Gas Company via a newly executed agreement through the end of 2010. On April 29, 2009, Duke Energy Carolinas and the City of Orangeburg filed a Notice of Appeal with the North Carolina Court of Appeals and briefs were filed with the Court of Appeals on December 16, 2009. The City of Fayetteville and ElectriCities filed briefs in support of Duke Energy Carolinas' and City of Orangeburg's positions. Briefs for the appellees are due on February 17, 2010. Additionally, on July 2, 2009, the City of Orangeburg filed a Petition for Declaratory Order with the FERC seeking relief from the NCUC Order on various grounds, including violation of the Public Utility Regulatory Policies Act voluntary coordination provisions and federal preemption. The NCUC, the Public Staff and the Attorney General, Progress Energy, the National Association of Regulatory Utility Commissioners, Occidental Power Marketing and the North Carolina Waste Awareness Network (WARN) have intervened in opposition to the Petition. The City of Fayetteville and ElectriCities have intervened in favor of Orangeburg's position, as has the American Public Power Association. Duke Energy Carolinas and NC Electric Membership Cooperative have also intervened, but expressed no position on the Petition.

Duke Energy Carolinas Wholesale Sales.

On September 3, 2009, Duke Energy Carolinas filed advance notice of its intent to serve Central Electric Power Cooperative, Inc. as an additional wholesale customer at native load priority and at system average cost. The load to be served consists of load historically served by Duke Energy Carolinas until recently. On September 11, 2009, the Public Staff filed its response to the advance notice, indicating that it did not object to the advance notice filing and further indicating that it was unlikely that the Public Staff would in a future rate proceeding recommend that costs associated with the Central Electric Power cooperative, Inc. contract be allocated on anything other than system average cost. On October 5, 2009, the WARN filed a petition to intervene in the proceeding arguing that the extension of Duke Energy Carolinas' service area through wholesale sales is not in the best interests of Duke Energy Carolinas' customers. On November 10, 2009, the NCUC issued an order rejecting WARN's objection and permitting Duke Energy Carolinas to proceed with the proposed agreement.

Duke Energy Carolinas has also filed advance notices of its intent to serve additional wholesale customers; namely, the City of Greenwood, South Carolina, and Haywood Electric Membership Corp., at native load priority. Given that these wholesale customers were historically served by Duke Energy Carolinas for a portion of their load, Duke Energy Carolinas will seek to distinguish these contracts from the Orangeburg decision. On July 20, 2009, the NCUC issued an order concluding that Duke Energy Carolinas can proceed with the Greenwood purchased power agreement and that Greenwood's load may be treated the same as retail native load.

Duke Energy Indiana SmartGrid and Distributed Renewable Generation Demonstration Project.

Duke Energy Indiana filed a petition and case-in-chief testimony supporting its request to build an intelligent distribution grid in Indiana. The proposal requests approval of distribution formula rates or, in the alternative, a SmartGrid Rider to recover the return on and of the capital costs of the build-out and the recovery of incremental operating and maintenance expenses and lost revenues. The petition also includes a pilot program for the installation of small solar photovoltaic and wind generation on customer sites, for approximately $10 million over a three-year period. Duke Energy Indiana filed supplemental testimony in January 2009 to reflect the impacts of new favorable tax treatment on the cost/benefit analysis for SmartGrid. The intervenors filed testimony generally supporting SmartGrid, but claimed that Duke Energy Indiana's plan was too fast and too large, with not enough customer benefits in terms of time differentiated rate options and behind-the-meter energy management systems. The intervenors also opposed the distribution formula rate and the rider request claiming that costs should be recovered in a base rate case, or possibly deferred. Duke Energy Indiana filed rebuttal testimony agreeing to slow its deployment, and agreeing to work with the parties collaboratively to design time differentiated rate and energy management system pilots. On June 4, 2009, Duke Energy Indiana filed with the IURC a settlement agreement with the OUCC, the CAC, Nucor Corporation, and the Duke Energy Indiana Industrial Group which provided for a full deployment of Duke Energy Indiana's SmartGrid initiative at a slower pace, including cost recovery through a tracking mechanism. The settlement also included increased reporting and monitoring requirements, approval of Duke Energy Indiana's renewable distributed generation pilot and the creation of a collaborative design to initiate several time differentiated pricing pilots, an electric vehicle pilot and a home area network pilot. Additionally, the settlement agreement provided for tracker recovery of the costs associated with the SmartGrid initiative, subject to cost recovery caps and a termination date for the tracker. The tracker will also include a reduction in costs associated with the adoption of a new depreciation study. An evidentiary hearing was held on June 29, 2009. On November 4, 2009, the IURC issued an order that rejected the settlement agreement as incomplete and not in the public interest. The IURC cited the lack of defined benefits of the programs and encouraged the parties to continue the collaborative process outlined in the settlement or to consider smaller scale pilots or phased-in options. The IURC required the parties to present a procedural schedule within 10 days to address the underlying relief requested in the cause, and to supplement the record to address issues regarding the American Recovery and Reinvestment Act funding recently awarded by the DOE. Duke Energy Indiana is considering its next steps, including a review of the implications of this Order on the American Recovery and Reinvestment Act SmartGrid Investment Grant award from the DOE. A technical conference was held at the IURC on December 1, 2009, wherein a procedural schedule was established for the IURC's continuing review of Duke Energy Indiana's SmartGrid proposal. Duke Energy Indiana is currently scheduled to file supplemental testimony in support of a revised SmartGrid proposal by April 1, 2010, with an evidentiary hearing scheduled for May 5, 2010.

Duke Energy Ohio SmartGrid.

Duke Energy Ohio filed an application on June 30, 2009, to establish rates for return of its SmartGrid net costs incurred for gas and electric distribution service through the end of 2008. The rider for recovering electric SmartGrid costs was approved by the PUCO in its order approving the ESP, as discussed above. Duke Energy Ohio proposed its gas SmartGrid rider as part of its most recent gas distribution rate case. The PUCO Staff has completed its audit and filed its comments. The PUCO Staff and intervenors, the OCC and Kroger Company, filed comments on October 8, 2009. The OCC and Duke Energy Ohio filed reply comments on October 15, 2009. A Stipulation and Recommendation was entered into by Duke Energy Ohio, Staff of the PUCO, Kroger Company, and Ohio Partners for Affordable Energy, which provides for a revenue increase of approximately $4.2 million under the electric rider and $590,000 under the natural gas rider. The OCC did not oppose the Stipulation and Recommendation. A hearing on the Stipulation and Recommendation occurred on November 20, 2009. Approval of the Stipulation and Recommendation is expected in the first quarter of 2010.

Commercial Power.

As discussed in Note 1, effective December 17, 2008, Commercial Power reapplied regulatory accounting treatment to certain portions of its operations due to the passing of SB 221 and the PUCO's approval of the ESP. Commercial Power may be impacted by certain of the regulatory matters discussed above, including the Duke Energy Ohio electric rate filings.

Pioneer Transmission LLC Joint Venture.

On August 8, 2008, Duke Energy announced the formation of a 50-50 joint venture, called Pioneer Transmission, LLC (Pioneer Transmission), with American Electric Power Company, Inc. (AEP) to build and operate 240 miles of extra-high-voltage 765 KV transmission lines and related facilities in Indiana. Pioneer Transmission will be regulated by the FERC and the IURC. Both Duke Energy and AEP own an equal interest in the joint venture and will share equally in the project costs, which are currently estimated at approximately $1 billion, of which approximately $500 million is anticipated to be financed by Pioneer Transmission and the remaining amount split equally between Duke Energy and AEP. The joint venture will operate in Indiana as a transmission utility. The earliest possible in-service date for the project is in 2015. On March 27, 2009, the FERC issued an order granting favorable rate treatment for the project, including requested rate incentives. As is customary in formula rate cases, the FERC set the formula rate that transmission customers would pay for hearing and settlement procedures to address various challenges by intervenors to the inputs and calculations underlying the formula rate. These rate issues were resolved by a settlement which was approved by the FERC on October 26, 2009. Duke Energy continues to work with MISO and PJM to obtain the necessary approvals to be included in their respective transmission expansion plans.

5. JOINT OWNERSHIP OF GENERATING AND TRANSMISSION FACILITIES

Duke Energy Carolinas, along with North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation and Piedmont Municipal Power Agency, have joint ownership of Catawba Nuclear Station, which is a facility operated by Duke Energy Carolinas. As discussed in Note 3, in September 2008, Duke Energy paid approximately $150 million for an additional approximate 7% ownership interest in the Catawba Nuclear Station.

Duke Energy Ohio, Columbus Southern Power Company, and Dayton Power & Light jointly own electric generating units and related transmission facilities in Ohio. Duke Energy Kentucky and Dayton Power & Light jointly own an electric generating unit. Duke Energy Ohio and Wabash Valley Power Association, Inc. (WVPA) jointly own Vermillion Station. Additionally, Duke Energy Indiana is a joint-owner of Gibson Station Unit No. 5 with WVPA and Indiana Municipal Power Agency (IMPA), as well as a joint-owner with WVPA and IMPA of certain Indiana transmission property and local facilities. These facilities constitute part of the integrated transmission and distribution systems, which are operated and maintained by Duke Energy Indiana.

Duke Energy's share of jointly-owned plant or facilities included on the December 31, 2009 Consolidated Balance Sheet is as follows:

(in millions)	Ownership Share	Property, Plant, and Equipment	Accumulated Depreciation	Construction Work in Progress
Duke Energy Carolinas				
Production:				
Catawba Nuclear Station (Units 1 and 2)[a]	19.2%	$ 827	$ 312	$ 5
Duke Energy Ohio				
Production:				
Miami Fort Station (Units 7 and 8)[b]	64.0	596	176	11
W.C. Beckjord Station (Unit 6)[b]	37.5	55	31	1
J.M. Stuart Station[b][c]	39.0	765	221	17
Conesville Station (Unit 4)[b][c]	40.0	292	57	14
W.M. Zimmer Station[b]	46.5	1,316	516	13
Killen Station[b][c]	33.0	297	131	1
Vermillion[b]	75.0	197	53	—
Transmission[a]	Various	91	53	—
Duke Energy Indiana				
Production:				
Gibson Station (Unit 5)[a]	50.1	327	161	—
Transmission and local facilities[a]	Various	3,148	1,335	—
Duke Energy Kentucky				
Production:				
East Bend Station[a]	69.0	430	226	2
International Energy				
Production:				
Brazil — Canoas I and II	47.1	357	83	—

(a) Included in U.S. Franchised Electric and Gas segment.
(b) Included in Commercial Power segment.
(c) Station is not operated by Duke Energy Ohio.

Duke Energy's share of revenues and operating costs of the above jointly owned generating facilities are included within the corresponding line on the Consolidated Statements of Operations. Each participant in the jointly owned facilities must provide its own financing.

6. INCOME TAXES

The following details the components of income tax expense:

Income Tax Expense

(in millions)	2009	2008	2007
	For the Years Ended December 31,		
Current income taxes			
Federal	$(271)	$ 60	$ (59)
State	3	17	24
Foreign	96	68	64
Total current income taxes	(172)	145	29
Deferred income taxes			
Federal	767	388	627
State	148	50	37
Foreign	27	46	32
Total deferred income taxes	942	484	696
Investment tax credit amortization	(12)	(13)	(13)
Total income tax expense from continuing operations	758	616	712
Total income tax expense (benefit) from discontinued operations	(2)	(3)	(88)
Total income tax expense from extraordinary item	—	37	—
Total income tax expense included in Consolidated Statements of Operations[a]	$ 756	$650	$624

(a) Included in the "Total current income taxes" line above are uncertain tax benefits relating primarily to certain temporary differences of approximately $91 million for 2009, $46 million for 2008 and $245 million for 2007.

Income from Continuing Operations before Income Taxes

(in millions)	2009	2008	2007
	For the Years Ended December 31,		
Domestic	$1,433	$1,575	$1,894
Foreign	398	316	342
Total income from continuing operations before income taxes	$1,831	$1,891	$2,236

Reconciliation of Income Tax Expense at the U.S. Federal Statutory Tax Rate to the Actual Tax Expense from Continuing Operations (Statutory Rate Reconciliation)

(in millions)	2009	2008	2007
	For the Years Ended December 31,		
Income tax expense, computed at the statutory rate of 35%	$ 641	$ 663	$ 782
State income tax, net of federal income tax effect	98	43	40
Tax differential on foreign earnings	(16)	3	(23)
Goodwill impairment charge	130	—	—
AFUDC equity income	(53)	(52)	(24)
Other items, net	(42)	(41)	(63)
Total income tax expense from continuing operations	$ 758	$ 616	$ 712
Effective tax rate	41.4%	32.5%	31.9%

During 2009, Duke Energy had tax benefits related to employee stock ownership plan dividends of approximately $22 million and renewable energy credits primarily related to the DEGS wind business of approximately $30 million. These benefits are reflected in the above table in Other items, net.

During 2008, Duke Energy had tax benefits related to employee stock ownership plan dividends of approximately $20 million and certain foreign restructuring of approximately $25 million. These benefits are reflected in the above table in Other items, net.

During 2007, Duke Energy had tax benefits related to employee stock ownership plan dividends of approximately $20 million and the manufacturing deduction of approximately $35 million, which is reflected in the above table in Other items, net. The manufacturing deduction was created by the American Job Creation Act of 2004 (the Act). The Act provides a deduction for income from qualified domestic production activities. The manufacturing deduction amounts to 6% on qualified production activities.

Valuation allowances have been established for certain foreign and state net operating loss carryforwards that reduce deferred tax assets to an amount that will be realized on a more-likely-than-not basis. The net change in the total valuation allowance is included in Tax differential on foreign earnings and State income tax, net of federal income tax effect in the above table.

Net Deferred Income Tax Liability Components

(in millions)	December 31, 2009	2008
Deferred credits and other liabilities	$ 591	$ 995
Tax Credit Carryforwards[a]	290	—
Other	260	—
Total deferred income tax assets	1,141	995
Valuation allowance	(163)	(94)
Net deferred income tax assets	978	901
Investments and other assets	(594)	(764)
Accelerated depreciation rates	(4,744)	(4,125)
Regulatory assets and deferred debits	(1,184)	(856)
Other	—	(30)
Total deferred income tax liabilities	(6,522)	(5,775)
Net deferred income tax liabilities	$(5,544)	$(4,874)

(a) Of the tax credit carryforwards, approximately $218 million relate to investment tax credits expiring in 2029 and approximately $72 million relates to alternative minimum tax credits that have no expiration.

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

Deferred Tax Liabilities

(in millions)	December 31, 2009	2008
Current deferred tax assets, included in other current assets	$ 3	$ 158
Non-current deferred tax assets, included in other investments and other assets	95	97
Current deferred tax liabilities, included in other current liabilities	(27)	(12)
Non-current deferred tax liabilities	(5,615)	(5,117)
Total net deferred income tax liabilities	$(5,544)	$(4,874)

Deferred income taxes and foreign withholding taxes have not been provided on undistributed earnings of Duke Energy's foreign subsidiaries when such amounts are deemed to be indefinitely reinvested. The cumulative undistributed earnings as of December 31, 2009 on which Duke Energy has not provided deferred income taxes and foreign withholding taxes is approximately $949 million.

Duke Energy or its subsidiaries file income tax returns in the U.S. with federal and various state governmental authorities, and in foreign jurisdictions.

Changes to Unrecognized Tax Benefits

(in millions)	2009 Increase/ (Decrease)	2008 Increase/ (Decrease)	2007 Increase/ (Decrease)
Unrecognized Tax Benefits — January 1,	$572	$348	$499
Spin-off of Spectra Energy	—	—	(78)
Unrecognized Tax Benefits — January 2,	572	348	421
Unrecognized Tax Benefits Changes			
Gross increases — tax positions in prior periods	132	294	36
Gross decreases — tax positions in prior periods	(38)	(65)	(56)
Gross increases — current period tax positions	11	5	1
Settlements	(13)	(7)	(52)
Lapse of statute of limitations	—	(3)	(2)
Total Changes	92	224	(73)
Unrecognized Tax Benefits — December 31,	$664	$572	$348

At December 31, 2009, Duke Energy had approximately $303 million of unrecognized tax benefits that, if recognized, would affect the effective tax rate or be classified as a regulatory liability. At this time, Duke Energy is unable to estimate the specific effect to either. At December 31, 2009, Duke Energy had approximately $13 million that, if recognized, would be recorded as a component of discontinued operations.

It is reasonably possible that Duke Energy will reflect an approximate $313 million reduction in unrecognized tax benefits within the next 12 months due to expected settlements.

During the years ending December 31, 2009, 2008, and 2007, Duke Energy recognized approximately $7 million of net interest expense, and approximately $2 million and $38 million of net interest income, respectively, related to income taxes. At December 31, 2009, and 2008, Duke Energy's Consolidated Balance Sheets included approximately $21 million and $29 million, respectively, of interest receivable, which reflects all interest related to income taxes, and approximately $3 million and $2 million, respectively, related to accruals for the payment of penalties.

Duke Energy has the following tax years open.

Jurisdiction	Tax Years
Federal	1999 and after (except for Cinergy and its subsidiaries, which are open for years 2005 and after)
State	Majority closed through 2001 except for certain refund claims for tax years 1978-2001 and any adjustments related to open federal years
International	2000 and after

As of December 31, 2009 and 2008, approximately $359 million and $490 million, respectively, of federal income tax receivables were included in Other within Current Assets on the Consolidated Balance Sheets. At both December 31, 2009 and 2008, these balances exceeded 5% of Total Current Assets.

7. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected costs for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. The present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation (with corresponding adjustments to property, plant, and equipment), which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired and changes in federal, state or local regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset. The recognition of asset retirement obligations has no impact on the earnings of Duke Energy's regulated electric operations as the effects of the recognition and subsequent accounting for an asset retirement obligation are offset by the establishment of regulatory assets and liabilities pursuant to regulatory accounting.

Asset retirement obligations recognized by Duke Energy relate primarily to the decommissioning of nuclear power facilities, obligations related to right-of-way agreements, asbestos removal and contractual leases for land use. Certain of Duke Energy's assets have an indeterminate life, such as transmission and distribution facilities and some gas-fired power plants and thus the fair value of the retirement obligation is not reasonably estimable. A liability for these asset retirement obligations will be recorded when a fair value is determinable.

The following table presents the changes to the liability associated with asset retirement obligations during the years ended December 31, 2009 and 2008:

	Years Ended December 31,	
(in millions)	2009	2008
Balance as of January 1,	$2,567	$2,351
Liabilities incurred due to new acquisitions[(a)]	—	44
Accretion expense[(b)]	200	164
Liabilities settled	—	(2)
Revisions in estimates of cash flows[(c)]	389	—
Liabilities incurred in the current year	35	10
Other	(6)	—
Balance as of December 31,	$3,185	$2,567

(a) As discussed in Note 3, in September 2008, Duke Energy acquired an additional ownership interest in Catawba.
(b) Substantially all of the accretion expense for the years ended December 31, 2009 and 2008 relate to Duke Energy's regulated electric operations and have been deferred in accordance with regulatory accounting treatment, as discussed above.
(c) As discussed below, Duke Energy updates its nuclear decommissioning costs study every five years as required by the NCUC and PSCSC. The increase in the revisions to estimated cash flows primarily relates to the increase in estimated cost of decommissioning Duke Energy's nuclear units. Approximately half of the increase in the nuclear decommissioning cost estimates is due to increased labor costs since the completion of the last cost study in 2003. Other assumptions that had changed since the 2003 study that impacted the determination of the asset retirement obligation liability include the inflation rate, market risk premium and credit adjusted risk free rate.

Duke Energy's regulated electric and regulated natural gas operations accrue costs of removal for property that does not have an associated legal retirement obligation based on regulatory orders from the various state commissions. These costs of removal are recorded as a regulatory liability in accordance with regulatory treatment. Duke Energy does not accrue the estimated cost of removal when no legal obligation associated with retirement or removal exists for any non-regulated assets (including Duke Energy Ohio's generation assets). The total amount of cost of removal for assets without an associated legal retirement obligation, which are included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets, was $2,277 million and $2,162 million as of December 31, 2009 and 2008, respectively.

Nuclear Decommissioning Costs.

In 2005, the NCUC and PSCSC approved a $48 million annual amount for contributions and expense levels for decommissioning. In each of the years ended December 31, 2009, 2008 and 2007, Duke Energy expensed approximately $48 million and contributed cash of approximately $48 million to the NDTF for decommissioning costs. These amounts are presented in the Consolidated Statements of Cash Flows in Purchases of Available-For-Sale Securities within Net Cash Used in Investing Activities. The entire amount of these contributions were to the funds reserved for contaminated costs as contributions to the funds reserved for non-contaminated costs have been discontinued since the current estimates indicate existing funds to be sufficient to cover projected future costs. Both the NCUC and the PSCSC have allowed Duke Energy to recover estimated decommissioning costs through retail rates over the expected remaining service periods of Duke Energy's nuclear stations. Duke Energy believes that the decommissioning costs being recovered through rates, when coupled with expected fund earnings, will be sufficient to provide for the cost of future decommissioning.

The balance of the external NDTF, which are reflected as NDTF within Investments and Other Assets in the Consolidated Balance Sheets, was approximately $1,765 million as of December 31, 2009 and $1,436 million as of December 31, 2008. The increase in the value of the NDTF during 2009 is due to higher overall returns in the equity and debt markets. The fair value of assets legally restricted for the purpose of settling asset retirement obligations associated with nuclear decommissioning was $1,530 million as of December 31, 2009 and $1,194 million as of December 31, 2008.

As the NCUC and the PSCSC require that Duke Energy update its cost estimate for decommissioning its nuclear plants every five years, new site-specific nuclear decommissioning cost studies were completed in January 2009 that showed total estimated nuclear decommissioning costs, including the cost to decommission plant components not subject to radioactive contamination, of approximately $3 billion in 2008 dollars. This estimate includes Duke Energy's 19.25% ownership interest in the Catawba Nuclear Station. The other joint owners of Catawba Nuclear Station are responsible for decommissioning costs related to their ownership interests in the station. The previous study, completed in 2004, estimated total nuclear decommissioning costs, including the cost to decommission plant components not subject to radioactive contamination, of approximately $2.3 billion in 2003 dollars.

Duke Energy filed these site-specific nuclear decommissioning cost studies with the NCUC and the PSCSC in conjunction with the various rate case filings. In addition to the decommissioning cost studies, a new funding study was completed and indicates the current annual funding requirement of approximately $48 million is sufficient to cover the estimated decommissioning costs. Duke Energy received an order from the NCUC on its rate case filing on December 7, 2009, and the PSCSC accepted a settlement agreement on Duke Energy's rate case on January 20, 2010. Both the NCUC and the PSCSC approved the existing $48 million annual funding level for nuclear decommissioning costs.

The operating licenses for Duke Energy's nuclear units are subject to extension. In December 2003, Duke Energy was granted renewed operating licenses for Catawba Nuclear Station Units 1 and 2 until 2043 and McGuire Nuclear Station Unit 1 and 2 until 2041 and 2043, respectively. In 2000, Duke Energy was granted a renewed operating license for the Oconee Nuclear Station Units 1 and 2 until 2033 and Unit 3 until 2034.

8. RISK MANAGEMENT, DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The primary risks Duke Energy manages by utilizing derivative instruments are commodity price risk and interest rate risk. Duke Energy closely monitors the risks associated with commodity price changes and changes in interest rates on its operations and, where appropriate, uses various commodity and interest rate instruments to manage these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as hedging instruments, while others either do not qualify as a hedge or have not been designated as hedges by Duke Energy (hereinafter referred to as undesignated contracts). Duke Energy's primary use of energy commodity derivatives is to hedge its generation portfolio against exposure to changes in the prices of power and fuel. Interest rate swaps are entered into to manage interest rate risk primarily associated with Duke Energy's variable-rate and fixed-rate borrowings.

The accounting guidance for derivatives requires the recognition of all derivative instruments not identified as NPNS as either assets or liabilities at fair value in the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, Duke Energy may elect to designate such derivatives as either cash flow hedges or fair value hedges.

The operations of U.S. Franchised Electric and Gas business segment and certain operations of the Commercial Power business segment meet the criteria for regulatory accounting treatment. Accordingly, for derivatives designated as cash flow hedges within the regulated operations, gains and losses are reflected as a regulatory liability or asset instead of as a component of AOCI. For derivatives designated as fair value hedges or left undesignated within the regulated operations, including economic hedges associated with Commercial Power's native load generation, gains and losses associated with the change in fair value of these derivative contracts would be deferred as a regulatory liability or asset, thus having no immediate earnings impact.

Within Duke Energy's unregulated businesses, for derivative instruments that qualify for hedge accounting and are designated as cash flow hedges, the effective portion of the gain or loss is reported as a component of AOCI and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Any gains or losses on the derivative that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item are recognized in earnings in the current period. Duke Energy includes the gain or loss on the derivative in the same line item as the offsetting loss or gain on the hedged item in the Consolidated Statements of Operations. Additionally, Duke Energy enters into derivative agreements that are economic hedges that either do not qualify for hedge accounting or have not been designated as a hedge. The changes in fair value of these undesignated derivative instruments are reflected in current earnings.

Commodity Price Risk

Duke Energy is exposed to the impact of market changes in the future prices of electricity (energy, capacity and financial transmission rights), coal, natural gas and emission allowances (SO_2, seasonal NO_X and annual NO_X) as a result of its energy operations such as electric generation and the transportation and sale of natural gas. With respect to commodity price risks associated with electric generation, Duke Energy is exposed to changes including, but not limited to, the cost of the coal and natural gas used to generate electricity, the prices of electricity in wholesale markets, the cost of capacity required to purchase and sell electricity in wholesale markets and the cost of emission allowances for SO_2, seasonal NO_X and annual NO_X, primarily at Duke Energy's coal fired power plants. Duke Energy closely monitors the risks associated with commodity price changes on its future operations and, where appropriate, uses various commodity contracts to mitigate the effect of such fluctuations on operations. Duke Energy's exposure to commodity price risk is influenced by a number of factors, including, but not limited to, the term of the contract, the liquidity of the market and delivery location.

Commodity derivatives associated with the risk management of Duke Energy's energy operations may be accounted for as either cash flow hedges or fair value hedges if the derivative instrument qualifies as a hedge under the accounting guidance for derivatives, or as an undesignated contract if either the derivative instrument does not qualify as a hedge or Duke Energy has elected to not designate the contract as a hedge. Additionally, Duke Energy enters into various contracts that qualify for the NPNS exception. Duke Energy primarily applies the NPNS exception to contracts within the U.S. Franchised Electric and Gas and Commercial Power business segments that relate to the physical delivery of electricity over the next 12 years.

Commodity Fair Value Hedges.

At December 31, 2009, Duke Energy did not have any open commodity derivative instruments that were designated as fair value hedges.

Commodity Cash Flow Hedges.

Duke Energy uses commodity instruments, such as swaps, futures, forwards and options, to protect margins for a portion of future revenues and fuel and purchased power expenses. Duke Energy generally uses commodity cash flow hedges to mitigate exposures to the price variability of the underlying commodities for, generally, a maximum period of one year.

Undesignated Contracts.

Duke Energy uses derivative contracts as economic hedges to manage the market risk exposures that arise from providing electric generation and capacity to large energy customers, energy aggregators and other wholesale companies. Undesignated contracts include contracts not designated as a hedge, contracts that do not qualify for hedge accounting, derivatives that no longer qualify for the NPNS scope exception, and de-designated hedge contracts that were not re-designated as a hedge. The contracts in this category as of December 31, 2009 are primarily associated with forward power sales and coal purchases, as well as forward SO_2 emission allowances, for the Commercial Power and U.S. Franchised Electric and Gas business segments. Undesignated contracts also include contracts associated with operations that Duke Energy continues to wind down or has included as discontinued operations.

In connection with the exiting of the DENA business in 2005, Duke Energy entered into a series of Total Return Swaps (TRS) with Barclays Bank PLC (Barclays), which are accounted for as mark-to-market derivatives. The TRS offsets the net fair value of the contracts being sold to Barclays. The fair value of the TRS as of December 31, 2009 is an asset of approximately $12 million, which offsets the net fair value of the underlying contracts, which is a liability of approximately $12 million. The remaining contracts covered by this TRS are with a single counterparty. Although Duke Energy has transferred the risks associated with these contracts to Barclay's via the TRS, Duke Energy will continue to facilitate these contracts for their duration.

Interest Rate Risk

Duke Energy is exposed to risk resulting from changes in interest rates as a result of its issuance or anticipated issuance of variable and fixed-rate debt and commercial paper. Duke Energy manages its interest rate exposure by limiting its variable-rate exposures to a percentage of total capitalization and by monitoring the effects of market changes in interest rates. To manage risk associated with changes in interest rates, Duke Energy may enter into financial contracts, primarily interest rate swaps and U.S. Treasury lock agreements. The majority of Duke Energy's currently outstanding derivative instruments related to interest rate risk are hedges.

Additionally, in anticipation of certain fixed-rate debt issuances, Duke Energy may execute a series of forward starting interest rate swaps to lock in components of the market interest rates at the time and terminate these derivatives prior to or upon the issuance of the corresponding debt. When these transactions occur within a business that applies regulatory accounting treatment, any pre-tax gain or loss recognized from inception to termination of the hedges may be recorded as a regulatory liability or asset and amortized as a component of interest expense over the life of the debt. Alternatively, Duke Energy may designate these derivatives as hedges. If so, any pre-tax gain or loss recognized from inception to termination of the hedges is recorded in AOCI and amortized as a component of interest expense over the life of the debt.

At December 31, 2009, the total notional amount of Duke Energy's receive fixed/pay-variable interest rate swaps (fair value hedge) was $275 million and the total notional amount of Duke Energy's receive variable/pay-fixed interest rate swaps (cash flow hedge) was $91 million.

Volumes

The following table shows information relating to the volume of Duke Energy's derivative activity outstanding as of December 31, 2009. Amounts disclosed represent the notional volumes of commodities and the notional dollar amounts of debt subject to derivative contracts accounted for at fair value. For option contracts, notional amounts include only the delta-equivalent volumes which represent the notional volumes times the probability of exercising the option based on current price volatility. Volumes associated with contracts qualifying for the NPNS exception have been excluded from the table below. Amounts disclosed represent the absolute value of notional amounts. Duke Energy has netted contractual amounts where offsetting purchase and sale contracts exist with identical delivery locations and times of delivery.

Underlying Notional Amounts for Derivative Instruments Accounted for At Fair Value

	December 31, 2009
Commodity contracts	
Electricity-energy (Gigawatt-hours)	3,687
Emission allowances: SO_2 (thousands of tons)	9
Emission allowances: NO_X (thousands of tons)	2
Natural gas (millions of decatherms)	71
Coal (millions of tons)	2
Financial contracts	
Interest rates (dollars in millions)	$ 366

The following table shows fair value amounts of derivative contracts as of December 31, 2009 and the line item(s) in the Consolidated Balance Sheets in which such amounts are included. The fair values of derivative contracts are presented on a gross basis, even when the derivative instruments are subject to master netting arrangements. Cash collateral payables and receivables associated with the derivative contracts have not been netted against the fair value amounts.

Location and Fair Value Amounts of Derivatives Reflected in the Consolidated Balance Sheets

	December 31, 2009	
(in millions)	Asset Derivatives	Liability Derivatives
Balance Sheet Location		
Derivatives Designated as Hedging Instruments		
Commodity contracts		
Current Assets: Other	$ 1	$ —
Interest rate contracts		
Current Assets: Other	4	—
Current Liabilities: Other	—	1
Deferred Credits and Other Liabilities: Other	—	6
Total Derivatives Designated as Hedging Instruments	$ 5	$ 7
Derivatives Not Designated as Hedging Instruments		
Commodity contracts		
Current Assets: Other	$ 59	$ 1
Investments and Other Assets: Other	59	2
Current Liabilities: Other	85	232
Deferred Credits and Other Liabilities: Other	44	100
Interest rate contracts		
Current Liabilities: Other	—	3
Deferred Credits and Other Liabilities: Other	—	4
Total Derivatives Not Designated as Hedging Instruments	$247	$342
Total Derivatives	$252	$349

The following table shows the amount of the gains and losses recognized on derivative instruments designated and qualifying as cash flow hedges by type of derivative contract during the year ended December 31, 2009 and the financial statement line items in which such gains and losses are included.

Cash Flow Hedges — Location and Amount of Pre-Tax Losses Recognized in Comprehensive Income

(in millions)	Year Ended December 31, 2009
Location of Pre-Tax Losses Reclassified from AOCI into Earnings[a]	
Commodity contracts	
Revenue, non-regulated electric, natural gas and other	$(13)
Fuel used in electric generation and purchased power-non-regulated	(10)
Interest rate contracts	
Interest expense	(5)
Total Pre-Tax Losses Reclassified from AOCI into Earnings	$(28)

(a) Represents the gains and losses on cash flow hedges previously recorded in AOCI during the term of the hedging relationship and reclassified into earnings during the current period.

The effective portion of gains or losses on cash flow hedges that were recognized in AOCI during the year ended December 31, 2009 was insignificant. In addition, there were no losses due to hedge ineffectiveness during the year ended December 31, 2009. No gains or losses have been excluded from the assessment of hedge effectiveness. As of December 31, 2009, an insignificant amount of pre-tax deferred net gains on derivative instruments related to commodity and interest rate cash flow hedges accumulated on the Consolidated Balance Sheets in AOCI are expected to be recognized in earnings during the next 12 months as the hedged transactions occur.

The following table shows the amount of the pre-tax gains and losses recognized on undesignated hedges by type of derivative instrument during the year ended December 31, 2009 and the line item(s) in the Consolidated Statements of Operations in which such gains and losses are included or deferred on the Consolidated Balance Sheets as regulatory assets or liabilities.

Undesignated Hedges — Location and Amount of Pre-Tax Gains and (Losses) Recognized in Income or as Regulatory Assets or Liabilities

(in millions)	Year Ended December 31, 2009
Location of Pre-Tax Gains Recognized in Earnings	
Commodity contracts	
Revenue, regulated electric	$ 1
Revenue, non-regulated electric, natural gas and other	1
Fuel used in electric generation and purchased power-non-regulated	10
Interest rate contracts	
Interest expense	1
Total Pre-Tax Gains Recognized in Earnings	$ 13
Location of Pre-Tax Gains (Losses) Recognized as Regulatory Assets or Liabilities	
Commodity contracts	
Regulatory Asset	$(48)
Regulatory Liability	3
Interest rate contracts	
Regulatory Asset	1
Total Pre-Tax Losses Recognized as Regulatory Assets or Liabilities	$(44)

Credit Risk

Duke Energy's principal customers for power and natural gas marketing and transportation services are industrial end-users, marketers, local distribution companies and utilities located throughout the U.S. and Latin America. Duke Energy has concentrations of receivables from natural gas and electric utilities and their affiliates, as well as industrial customers and marketers throughout these regions. These concentrations of customers may affect Duke Energy's overall credit risk in that risk factors can negatively impact the credit quality of the entire sector. Where exposed to credit risk, Duke Energy analyzes the counterparties' financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of those limits on an ongoing basis.

Duke Energy's industry has historically operated under negotiated credit lines for physical delivery contracts. Duke Energy frequently uses master collateral agreements to mitigate certain credit exposures, primarily related to hedging the risks inherent in its generation portfolio. The collateral agreements provide for a counterparty to post cash or letters of credit to the exposed party for exposure in excess of an established threshold. The threshold amount represents an unsecured credit limit, determined in accordance with the corporate credit policy. Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions.

Duke Energy also obtains cash, letters of credit or surety bonds from customers to provide credit support outside of collateral agreements, where appropriate, based on its financial analysis of the customer and the regulatory or contractual terms and conditions applicable to each transaction.

Certain of Duke Energy's derivative contracts contain contingent credit features, such as material adverse change clauses or payment acceleration clauses that could result in immediate payments, the posting of letters of credit or the termination of the derivative contract before maturity if specific events occur, such as a downgrade of Duke Energy's credit rating below investment grade.

The following table shows information with respect to derivative contracts that are in a net liability position and contain objective credit-risk related payment provisions. The amounts disclosed in the table below represents the aggregate fair value amounts of such derivative instruments at the end of the reporting period, the aggregate fair value of assets that are already posted as collateral under such derivative instruments at the end of the reporting period, and the aggregate fair value of additional assets that would be required to be transferred in the event that credit-risk-related contingent features were triggered at December 31, 2009.

Information Regarding Derivative Instruments that Contain Credit-risk Related Contingent Features

(in millions)	December 31, 2009
Aggregate Fair Value Amounts of Derivative Instruments in a Net Liability Position	$208
Collateral Already Posted	$130
Additional Cash Collateral or Letters of Credit in the Event Credit-risk-related Contingent Features were Triggered at the End of the Reporting Period	$ 6

Netting of Cash Collateral and Derivative Assets and Liabilities Under Master Netting Arrangements.

Duke Energy offsets fair value amounts (or amounts that approximate fair value) recognized on its Consolidated Balance Sheets related to cash collateral amounts receivable or payable against fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting agreement. At December 31, 2009 and 2008, Duke Energy had receivables related to the right to reclaim cash collateral of approximately $112 million and $86 million, respectively, and had payables related to obligations to return cash collateral of insignificant amounts that have been offset against net derivative positions in the Consolidated Balance Sheets. Duke Energy had collateral receivables of approximately $19 million and $64 million under master netting arrangements that have not been offset against net derivative positions at December 31, 2009 and 2008, respectively. Duke Energy had insignificant cash collateral payables under master netting arrangements that have not been offset against net derivative positions at December 31, 2009 and 2008.

See Note 9 for additional information on fair value disclosures related to derivatives.

9. FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

On January 1, 2008, Duke Energy adopted the new fair value disclosure requirements for financial instruments and non-financial derivatives. On January 1, 2009, Duke Energy adopted the new fair value disclosure requirements for non-financial assets and liabilities measured at fair value on a non-recurring basis. Duke Energy did not record any cumulative effect adjustment to retained earnings as a result of the adoption of the new fair value standards.

The accounting guidance for fair value defines fair value, establishes a framework for measuring fair value in GAAP in the U.S. and expands disclosure requirements about fair value measurements. Under the accounting guidance for fair value, fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received by Duke Energy to sell an asset or paid to transfer a liability versus an entry price, which would be the price paid to acquire an asset or received to assume a liability. Although the accounting guidance for fair value does not require additional fair value measurements, it applies to other accounting pronouncements that require or permit fair value measurements.

Duke Energy classifies recurring and non-recurring fair value measurements based on the following fair value hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 — unadjusted quoted prices in active markets for identical assets or liabilities that Duke Energy has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information. Duke Energy does not adjust quoted market prices on Level 1 for any blockage factor.

Level 2 — a fair value measurement utilizing inputs other than a quoted market price that are observable, either directly or indirectly, for the asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 — any fair value measurements which include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A level 3 measurement may be based primarily on level 2 inputs.

The fair value accounting guidance for financial instruments, which was effective for Duke Energy as of January 1, 2008, permits entities to elect to measure many financial instruments and certain other items at fair value that are not required to be accounted for at fair value under existing GAAP. Duke Energy does not currently have any financial assets or financial liabilities that are not required to be accounted for at fair value under GAAP for which it elected to use the option to record at fair value. However, in the future, Duke Energy may elect to measure certain financial instruments at fair value in accordance with this accounting guidance.

The following tables provide the fair value measurement amounts for assets and liabilities recorded on Duke Energy's Consolidated Balance Sheets at fair value at December 31, 2009 and 2008. Derivative amounts in the table below exclude cash collateral amounts which are disclosed in Note 8.

(in millions)	Total Fair Value Amounts at December 31, 2009	Level 1	Level 2	Level 3
Description				
Investments in available-for-sale auction rate securities[a][b]	$ 198	$ —	$ —	$198
Nuclear decommissioning trust fund equity securities[b]	1,156	1,156	—	—
Nuclear decommissioning trust fund debt securities[b]	609	36	573	—
Other long-term trading and available-for-sale equity securities[a][b]	66	60	6	—
Other long-term trading and available-for-sale debt securities[a][b]	258	32	226	—
Derivative assets[c]	120	1	24	95
Total Assets	$2,407	$1,285	$829	$293
Derivative liabilities[d]	(217)	(112)	(35)	(70)
Net Assets	$2,190	$1,173	$794	$223

(a) Included in Other within Investments and Other Assets on the Consolidated Balance Sheets.
(b) See Note 10 for additional information related to investments by major security type.
(c) Included in Other within Current Assets and Other within Investments and Other Assets on the Consolidated Balance Sheets. See Note 8 for additional information regarding derivatives.
(d) Included in Other within Current Liabilities and Other within Deferred Credits and Other Liabilities on the Consolidated Balance Sheets. See Note 8 for additional information regarding derivatives.

(in millions)	Total Fair Value Amounts at December 31, 2008	Level 1	Level 2	Level 3
Description				
Investments in available-for-sale auction rate securities[a][b]	$ 224	$ —	$ —	$ 224
Nuclear decommissioning trust fund equity securities[b]	831	831	—	—
Nuclear decommissioning trust fund debt securities[b]	605	22	583	—
Other long-term trading and available-for-sale equity securities[b][c]	80	49	31	—
Other long-term trading and available-for-sale debt securities[b][c]	234	25	209	—
Derivative assets[d]	251	9	70	172
Total Assets	$2,225	$936	$ 893	$ 396
Derivative liabilities[e]	(341)	(88)	(115)	(138)
Net Assets	$1,884	$848	$ 778	$ 258

(a) Approximately $173 million of auction rate securities are included in Other within Investments and Other Assets and approximately $51 million are classified as Short-Term Investments within Current Assets on the Consolidated Balance Sheets.
(b) See Note 10 for additional information related to investments by major security type.
(c) Included in Other within Investments and Other Assets on the Consolidated Balance Sheets.
(d) Included in Other within Current Assets and Other within Investments and Other Assets on the Consolidated Balance Sheets.
(e) Included in Other within Current Liabilities and Other within Deferred Credits and Other Liabilities on the Consolidated Balance Sheets

DUKE ENERGY CORPORATION
Notes to Consolidated Financial Statements – (Continued)

The following table provides a reconciliation of beginning and ending balances of assets and liabilities measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3):

Rollforward of Level 3 Measurements

(in millions)	Available-for-Sale Auction Rate Securities	Derivatives (net)	Total
Year Ended December 31, 2009			
Balance at January 1, 2009	$224	$ 34	$ 258
Total pre-tax realized or unrealized gains (losses) included in earnings:			
Revenue, non-regulated electric, natural gas, and other	—	(5)	(5)
Fuel used in electric generation and purchased power-non-regulated	—	16	16
Total pre-tax (losses) gains included in other comprehensive income	(10)	1	(9)
Net purchases, sales, issuances and settlements	(16)	(7)	(23)
Total losses included on balance sheet as regulatory asset or liability or as non-current liability	—	(14)	(14)
Balance at December 31, 2009	$198	$ 25	$ 223
Pre-tax amounts included in the Consolidated Statements of Operations related to Level 3 measurements outstanding at December 31, 2009:			
Revenue, non-regulated electric, natural gas, and other	$ —	$(14)	$ (14)
Fuel used in electric generation and purchased power-non-regulated	—	(12)	(12)
Total	$ —	$(26)	$ (26)
Year Ended December 31, 2008			
Balance at January 1, 2008	$ 15	$ 8	$ 23
Transfers in to Level 3	285	—	285
Total pre-tax realized or unrealized gains (losses) included in earnings:			
Revenue, non-regulated electric, natural gas, and other	—	(11)	(11)
Fuel used in electric generation and purchased power-non-regulated	—	96	96
Other income and expense, net	(3)	—	(3)
Total pre-tax losses included in other comprehensive income	(43)	(1)	(44)
Net purchases, sales, issuances and settlements	(30)	(84)	(114)
Total gains included on balance sheet as regulatory asset or liability or as non-current liability	—	26	26
Balance at December 31, 2008	$224	$ 34	$ 258
Pre-tax amounts included in the Consolidated Statements of Operations related to Level 3 measurements outstanding at December 31, 2008:			
Revenue, non-regulated electric, natural gas, and other	$ —	$ (3)	$ (3)
Fuel used in electric generation and purchased power-non-regulated	—	30	30
Other income and expense, net	(3)	—	(3)
Total	$ (3)	$ 27	$ 24

Valuation methods of the primary fair value measurements disclosed above are as follows:

Investments in equity securities:

Investments in equity securities are typically valued at the closing price in the principal active market as of the last business day of the quarter. Principal active markets for equity prices include published exchanges such as NASDAQ and NYSE. Foreign equity prices are translated from their trading currency using the currency exchange rate in effect at the close of the principal active market. Duke Energy has not adjusted prices to reflect for after-hours market activity. The majority of Duke Energy's investments in equity securities are valued using Level 1 measurements.

Investments in available-for-sale auction rate securities:

At December 31, 2009 and 2008, Duke Energy has approximately $251 million par value (approximately $198 million fair value) and approximately $270 million par value (approximately $224 million fair value), respectively, of auction rate securities for which an active market does not currently exist. The majority of these auction rate securities are AAA rated student loan securities for which substantially all the values are ultimately backed by the U.S. government. All of these securities were valued as of December 31, 2009 and 2008 using measurements appropriate for Level 3 investments. The methods and significant assumptions used to determine the fair values of Duke Energy's investment in auction rate debt securities represented a combination of broker-provided quotations and estimations of fair value using validation of such quotations through internal discounted cash flow models which incorporated primarily Duke Energy's own assumptions as to the term over which such investments will be recovered at par, the current level of interest rates, and the appropriate risk-adjusted (for liquidity and credit) discount rates when relevant observable inputs are not available to determine present value of such cash flows. In preparing the valuations, all significant value drivers were considered, including the underlying collateral.

See Note 10 for a discussion of other-than-temporary impairments associated with investments in auction rate debt securities during the year ended December 31, 2008.

Investments in debt securities:

Most debt investments are valued based on a calculation using interest rate curves and credit spreads applied to the terms of the debt instrument (maturity and coupon interest rate) and consider the counterparty credit rating. Most debt valuations are Level 2 measures. If the market for a particular fixed income security is relatively inactive or illiquid, the measurement is a Level 3 measurement. U.S. Treasury debt is typically a Level 1 measurement.

Commodity derivatives:

The pricing for commodity derivatives is primarily a calculated value which incorporates the forward price and is adjusted for liquidity (bid-ask spread), credit or non-performance risk (after reflecting credit enhancements such as collateral) and discounted to present value. The primary difference between a Level 2 and a Level 3 measurement has to do with the level of activity in forward markets for the commodity. If the market is relatively inactive, the measurement is deemed to be a Level 3 measurement. Some commodity derivatives are New York Mercantile Exchange (NYMEX) contracts, which Duke Energy classifies as Level 1 measurements.

Additional fair value disclosures.

The fair value of financial instruments, excluding financial assets and certain financial liabilities included in the scope of the accounting guidance for fair value measurements disclosed in the tables above, is summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 2009 and 2008 are not necessarily indicative of the amounts Duke Energy could have realized in current markets.

	As of December 31,			
	2009		2008	
(in millions)	Book Value	Approximate Fair Value	Book Value	Approximate Fair Value
Long-term debt, including current maturities	$17,015	$16,899	$13,896	$13,981

The fair value of cash and cash equivalents, accounts and notes receivable, accounts payable and commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments and/or because the stated rates approximate market rates.

See Note 11 for a discussion of non-recurring fair value measurements related to goodwill and other long-lived assets for which impairment charges were recorded during the third quarter of 2009.

See Note 20 for disclosure of fair value measurements for investments that support Duke Energy's qualified, non-qualified and other post-retirement benefit plans.

10. INVESTMENTS IN DEBT AND EQUITY SECURITIES

Duke Energy classifies its investments in debt and equity securities into two categories — trading and available-for-sale. Investments in debt and equity securities held in grantor trusts associated with certain deferred compensation plans are classified as trading securities and are reported at fair value in the Consolidated Balance Sheets with net realized and unrealized gains and losses included in earnings each period. All other investments in debt and equity securities are classified as available-for-sale securities, which are also reported at fair value on the Consolidated Balance Sheets with unrealized gains and losses excluded from earnings and reported either as a regulatory asset or liability, as discussed further below, or as a component of other comprehensive income until realized.

Duke Energy's available-for-sale securities are primarily comprised of investments held in the NDTF, investments in a grantor trust at Duke Energy Indiana related to other post-retirement benefit plans as required by the IURC, the captive insurance investment portfolio and investments in auction rate debt securities. The investments within the NDTF and Duke Energy Indiana's grantor trust are managed by independent investment managers with discretion to buy, sell and invest pursuant to the objectives set forth by the trust agreements. Therefore, Duke Energy has limited oversight of the day-to-day management of these investments. Since day-to-day investment decisions, including buy and sell decisions, are made by the investment manager, the ability to hold investments in unrealized loss positions is outside the control of Duke Energy. Accordingly, all unrealized losses associated with equity securities within the NDTF and Duke Energy Indiana's grantor trust are considered other-than-temporary and are recognized immediately when the fair value of individual investments is less than the cost basis of the investment. Pursuant to regulatory accounting, substantially all unrealized losses associated with investments in debt and equity securities within the NDTF and Duke Energy Indiana's grantor trust are deferred as a regulatory asset, thus there is no immediate impact on the earnings of Duke Energy as a result of any other-than-temporary impairments that would otherwise be required to be recognized in earnings. For investments in debt and equity securities held in the captive insurance portfolio and investments in auction rate debt securities, unrealized gains and losses are included in other comprehensive income until realized, unless it is determined that the carrying value of an investment is other-than-temporarily impaired, at which time the write-down to fair value may be included in earnings based on the criteria discussed below.

For available-for-sale securities outside of the NDTF and Duke Energy Indiana grantor trust, which are discussed separately above, Duke Energy analyzes all investment holdings each reporting period to determine whether a decline in fair value should be considered other-than-temporary. Criteria used to evaluate whether an impairment associated with equity securities is other-than-temporary includes, but is not limited to, the length of time over which the market value has been lower than the cost basis of the investment, the percentage decline compared to the cost of the investment and management's intent and ability to retain its investment in the issuer for a period of time sufficient to allow for any anticipated recovery in market value. If a decline in fair value is determined to be other-than-temporary, the investment is written down to its fair value through a charge to earnings.

With respect to investments in debt securities, during the first quarter of 2009, Duke Energy adopted the modified other-than-temporary impairment accounting guidance issued by the FASB, which changed the other-than-temporary impairment guidance related to investments in debt securities. Under this modified other-than-temporary impairment guidance, if the entity does not have an intent to sell the security and it is not more likely than not that management will be required to sell the debt security before the recovery of its cost basis, the impairment write-down to fair value would be recorded as a component of other comprehensive income, except for when it is determined that a credit loss exists. In determining whether a credit loss exists, management considers, among other things, the length of time and the extent to which the fair value has been less than the amortized cost basis, changes in the financial condition of the issuer of the security, or in the case of an asset backed security, the financial condition of the underlying loan obligors, consideration of underlying collateral and guarantees of amounts by government entities, ability of the issuer of the security to make scheduled interest or principal payments and any changes to the rating of the security by rating agencies. If it is determined that a credit loss exists, the amount of impairment write-down to fair value would be split between the credit loss, which would be recognized in earnings, and the amount attributable to all other factors, which would be recognized in other comprehensive income. The adoption of the modified other-than-temporary impairment guidance primarily impacts Duke Energy's investments in auction rate debt securities and the investments held in the captive insurance portfolio since, as discussed above, the debt securities held in the NDTF and Duke Energy Indiana's grantor trust receive regulatory deferral treatment of all unrealized losses including other-than-temporary impairments. Since management believes, based on consideration of the criteria above, that no credit loss exists as of December 31, 2009 and management does not have the intent to sell its investments in auction rate debt securities and the investments in debt securities within its captive insurance portfolio, and it is not more likely than not that management will be required to sell these securities before the anticipated recovery of their cost basis, management concluded that there were no other-than-temporary impairments necessary as of December 31, 2009. Accordingly, all changes in the market value of investments in auction rate debt securities and captive insurance investments were reflected as a component of other comprehensive income in 2009. However, during the year ended December 31, 2008, Duke Energy recorded a pre-tax impairment charge to earnings of approximately $13 million related to the credit risk of certain investments including auction rate debt securities. The remaining changes in fair value of investments in auction rate debt securities and captive insurance investments in 2008 were considered temporary and were reflected as a component of other comprehensive income. See Note 9 for additional information related to fair value measurements for investments in auction rate debt securities that were not part of its NDTF or captive insurance portfolio.

Management will continue to monitor the carrying value of its entire portfolio of investments in the future to determine if any additional other-than-temporary impairment losses should be recorded.

Investments in debt and equity securities are classified as either short-term investments or long-term investments based on management's intent and ability to sell these securities, taking into consideration illiquidity factors in the current markets with respect to certain short-term investments that have historically provided for a high degree of liquidity, such as investments in auction rate debt securities.

Short-term investments.

At December 31, 2008, Duke Energy had approximately $51 million carrying value (approximately $55 million par value) of short-term investments. The balance at December 31, 2008 consisted of investments in auction rate debt securities that either had a stated maturity within the next 12 months or Duke Energy believed the investments were reasonably expected to be refunded within the next 12 months based on notification of a refunding plan by the issuer. At December 31, 2008, management believed that approximately $49 million par value of investments in auction rate debt securities were reasonably expected to be refunded within the next 12 months based on notification of refunding by the issuer. However, due to an ongoing delay in that refunding plan, Duke Energy reclassified these securities to long-term investments in the second quarter of 2009. Duke Energy continues to hold these securities at December 31, 2009. The remaining balance of investments in auction rate debt securities at December 31, 2008 were included in long-term investments and are discussed below. During the year ended December 31, 2009 there were no purchases or sales of short-term investments. During the years ended December 31, 2008 and 2007, Duke Energy purchased short-term investments of approximately $4,277 million and $21,661 million, respectively. During the years ended December 31, 2008 and 2007, Duke Energy received proceeds on sales of approximately $4,424 million and $22,685 million, respectively.

Long-term investments.

Duke Energy classifies its investments in debt and equity securities held in the NDTF (see Note 7 for further information), in the Duke Energy Indiana grantor trust and the captive insurance investment portfolio as long-term. Additionally, approximately $198 million carrying value (approximately $251 million par value) and approximately $173 million carrying value (approximately $215 million par value) of investments in auction rate debt securities have been classified as long-term at December 31, 2009 and 2008, respectively, due to market illiquidity factors as a result of continued failed auctions. All of these investments are classified as available-for-sale and, therefore, are reflected on the Consolidated Balance Sheets at estimated fair value based on either quoted market prices or management's best estimate of fair value based on expected future cash flow using appropriate risk-adjusted discount rates. Since management does not intend to use these investments in current operations, these investments are classified as long-term. At December 31, 2009 and 2008, Duke Energy's long-term available-for-sale investments had a fair market value of $2,254 million and $1,855 million, respectively.

The cost of securities sold is determined using the specific identification method. During the years ended December 31, 2009, 2008 and 2007, Duke Energy purchased long-term investments of approximately $3,013 million, $3,076 million and $1,978 million, respectively, and received proceeds on sales of approximately $2,988 million $3,030 million and $1,928 million, respectively. The majority of these purchases and sales relate to activity within the NDTF, including annual contributions to the NDTF of approximately $48 million pursuant to an order by the NCUC (see Note 7).

The estimated fair values of short-term and long-term investments classified as available-for-sale are as follows (in millions):

	As of December 31,					
	2009			2008		
	Gross Unrealized Holding Gains[(a)]	Gross Unrealized Holding Losses[(a)]	Estimated Fair Value	Gross Unrealized Holding Gains[(a)]	Gross Unrealized Holding Losses[(a)]	Estimated Fair Value
Short-term Investments	$ —	$ —	$ —	$ —	$ (4)	$ 51
Total short-term investments	$ —	$ —	$ —	$ —	$ (4)	$ 51
Equity Securities	$337	$ (30)	$1,216	$161	$(163)	$ 880
Corporate Debt Securities	14	(2)	256	5	(7)	124
Municipal Bonds	2	(8)	83	2	(10)	150
U.S. Government Bonds	11	(1)	290	18	—	292
Auction Rate Securities	—	(53)	198	—	(42)	173
Other	18	(18)	211	3	(31)	236
Total long-term investments	$382	$(112)	$2,254	$189	$(253)	$1,855

(a) The table above includes unrealized gains and losses of approximately $374 million and $56 million, respectively, at December 31, 2009 and unrealized gains and losses of approximately $182 million and $190 million, respectively, at December 31, 2008 associated with investments held in the NDTF. Additionally, the table above includes unrealized gains of approximately $1 million and an insignificant amount of unrealized losses at December 31, 2009 and unrealized gains and losses of approximately $1 million and $14 million, respectively, at December 31, 2008 associated with investments held in the Duke Energy Indiana Grantor Trust. As discussed above, unrealized losses on investments within the NDTF and Duke Energy Indiana Grantor Trust are deferred as regulatory assets pursuant to regulatory accounting.

For the years ended December 31, 2009, 2008, and 2007, a pre-tax gain of approximately $7 million, a pre-tax loss of approx- imately $1 million, and a pre-tax gain of less than $1 million, respectively, were reclassified out of AOCI into earnings.

Debt securities held at December 31, 2009, which includes auction rate securities based on the stated maturity date, mature as follows: $44 million in less than one year, $173 million in one to five years, $156 million in six to 10 years and $657 million thereafter.

The fair values and gross unrealized losses of available-for-sale debt and equity securities which are in an unrealized loss position for which other-than-temporary impairment losses have not been recorded, summarized by investment type and length of time that the securities have been in a continuous loss position, are presented in the table below as of December 31, 2009 and 2008.

	As of December 31, 2009		
(in millions)	Fair Value[a]	Unrealized Loss Position >12 months	Unrealized Loss Position <12 months
Equity Securities	$164	$ (7)	$(23)
Corporate Debt Securities	38	—	(2)
Municipal Bonds	59	—	(8)
U.S. Government Bonds	93	(1)	—
Auction Rate Securities[b]	198	(53)	—
Other	51	(15)	(3)
Total	$603	$(76)	$(36)

	As of December 31, 2008		
(in millions)	Fair Value[a]	Unrealized Loss Position >12 months	Unrealized Loss Position <12 months
Equity Securities	$353	$(12)	$(151)
Corporate Debt Securities	38	(3)	(4)
Municipal Bonds	66	—	(10)
Auction Rate Securities[b]	224	—	(46)
Other	108	(3)	(28)
Total	$789	$(18)	$(239)

(a) The table above includes fair values of approximately $298 million and $486 million at December 31, 2009 and 2008, respectively, associated with investments held in the NDTF. Additionally, the table above includes fair values of approximately $27 million and $33 million at December 31, 2009 and 2008, respectively, associated with investments held in the Duke Energy Indiana Grantor Trust.

(b) See Note 9 for information about fair value measurements related to investments in auction rate debt securities.

11. GOODWILL AND INTANGIBLE ASSETS

Goodwill.

The following table shows goodwill by business segment at December 31, 2009 and 2008:

(in millions)	Balance January 1, 2009	Impairment of Goodwill	Acquisitions, Foreign Exchange and Other Changes	Balance December 31, 2009
U.S. Franchised Electric and Gas	$3,500	$ —	$(17)	$3,483
Commercial Power[a]	960	(371)	(20)	569
International Energy	260	—	38	298
Total consolidated	$4,720	$(371)	$ 1	$4,350

(in millions)	Balance January 1, 2008	Impairment of Goodwill	Acquisitions, Foreign Exchange and Other Changes	Balance December 31, 2008
U.S. Franchised Electric and Gas	$3,478	$—	$ 22	$3,500
Commercial Power	871	—	89	960
International Energy	293	—	(33)	260
Total consolidated	$4,642	$—	$ 78	$4,720

(a) The 2009 impairment charge, which is disclosed below, is the first goodwill impairment charge recorded by Duke Energy since the initial transaction occurred that resulted in the recognition of goodwill.

Duke Energy is required to perform an annual goodwill impairment test as of the same date each year and, accordingly, performs its annual impairment testing of goodwill as of August 31. Duke Energy updates the test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. The annual analysis of the potential impairment of goodwill requires a two step process. Step one of the impairment test involves comparing the fair values of reporting units with their aggregate carrying values, including goodwill. If the carrying amount of a reporting unit exceeds the reporting unit's fair value, step two must be performed to determine the amount, if any, of the goodwill impairment loss. If the carrying amount is less than fair value, further testing of goodwill impairment is not performed.

Step two of the goodwill impairment test involves comparing the implied fair value of the reporting unit's goodwill against the carrying value of the goodwill. Under step two, determining the implied fair value of goodwill requires the valuation of a reporting unit's identifiable tangible and intangible assets and liabilities as if the reporting unit had been acquired in a business combination on the testing date. The difference between the fair value of the entire reporting unit as determined in step one and the net fair value of all identifiable assets and liabilities represents the implied fair value of goodwill. The goodwill impairment charge, if any, would be the difference between the carrying amount of goodwill and the implied fair value of goodwill upon the completion of step two.

For purposes of the step one analyses, determination of reporting units' fair value was based on a combination of the income approach, which estimates the fair value of Duke Energy's reporting units based on discounted future cash flows, and the market approach, which estimates the fair value of Duke Energy's reporting units based on market comparables within the utility and energy industries. Based on completion of step one of the annual impairment analysis, management determined that the fair values of all reporting units except for Commercial Power's non-regulated Midwest generation reporting unit, for which the carrying value of goodwill was approximately $890 million as of August 31, 2009, were greater than their respective carrying values. Accordingly, only Commercial Power's non-regulated Midwest generation reporting unit required management to perform step two of the goodwill impairment test to determine the amount of the goodwill impairment.

Commercial Power's non-regulated Midwest generation reporting unit includes nearly 4,000 MW of coal-fired generation capacity in Ohio dedicated to serve Ohio native load customers under the ESP through December 31, 2011. These assets, as excess capacity allows, also generate revenues through sales outside the native load customer base, and such revenue is termed non-native. Additionally, this reporting unit has approximately 3,600 MW of gas-fired generation capacity in Ohio, Pennsylvania, Illinois and Indiana. The businesses within Commercial Power's non-regulated generation reporting unit operate in an unregulated environment in Ohio. As a result, the operations within this reporting unit are subjected to competitive pressures that do not exist in any of Duke Energy's regulated jurisdictions.

Commercial Power's other businesses, including the wind generation assets, are in a separate reporting unit for goodwill impairment testing purposes. No impairment exists with respect to Commercial Power's wind generation assets.

The fair value of the non-regulated Midwest generation reporting unit is impacted by a multitude of factors, including current and forecasted customer demand, current and forecasted power and commodity prices, impact of the economy on discount rates, valuation of peer companies, competition, and regulatory and legislative developments. Management's assumptions and views of these factors continually evolves, and such views and assumptions used in determining the step one fair value of the reporting unit in 2009 changed significantly from those used in the 2008 annual impairment test. These factors had a significant impact on the risk-adjusted discount rate and other inputs used to value the non-regulated Midwest generation reporting unit. More specifically, as of August 31, 2009, the following factors significantly impacted management's valuation of the reporting unit that consequently resulted in an approximate $371 million non-cash goodwill impairment charge during the third quarter of 2009:

- *Decline in load (electricity demand) forecast* — As a result of lower demand due to the continuing economic recession, forecasts evolved throughout 2009 that indicate that lower demand levels may persist longer than previously anticipated. The potential for prolonged suppressed sales growth, lower sales volume forecasts and greater uncertainty with respect to sales volume forecasts had a significant impact to the valuation of this reporting unit.
- *Depressed market power prices* — Low natural gas and coal prices have put downward pressure on market prices for power. As the economic recession continued throughout 2009, demand for power remained low and market prices were at lower levels than previously forecasted. In Ohio, Duke Energy provides power to retail customers under the ESP, which utilizes rates approved by the PUCO through 2011. These rates are currently above market prices for generation services. The current low levels of market prices impact price forecasts and places uncertainty over the pricing of power after the expiration of the ESP at the end of 2011. Additionally, customers have recently begun to select alternative energy generation service providers, as allowed by Ohio legislation, which further erodes margins on sales.
- *Carbon legislation/regulation developments* — On June 26, 2009, the U.S. House of Representatives passed The American Clean Energy and Security Act of 2009 (ACES) to encourage the development of clean energy sources and reduce greenhouse gas emissions. The ACES would create an economy-wide cap and trade program for large sources of greenhouse gas emissions. In September 2009, the U.S. Senate made significant progress towards their own version of climate legislation and, also in 2009, the EPA began actions that could lead to its regulation of greenhouse gas emissions absent carbon legislation. Climate legislation has the potential to significantly increase the costs of coal and other carbon-intensive electricity generation throughout the U.S., which could impact the value of the coal fired generating plants, particularly in non-regulated environments.

In addition to the goodwill impairment charge, and as a result of factors similar to those described above, Commercial Power recorded approximately $42 million of pre-tax impairment charges related to certain generating assets in the Midwest to write-down the value of these assets to their estimated fair value. These impairment charges are recorded in Goodwill and Other Impairment Charges on the Consolidated Statement of Operations. As management is not aware of any recent market transactions for comparable assets with sufficient transparency to develop a market approach fair value, Duke Energy relied on the income approach to estimate the fair value of the impaired assets.

The fair values of Commercial Power's non-regulated generation reporting unit and generating assets for which impairments were recorded were determined using significant unobservable inputs (i.e., Level 3 inputs) as defined by the accounting guidance for fair value measurements.

Intangibles.

The carrying amount and accumulated amortization of intangible assets as of December 31, 2009 and 2008 are as follows:

(in millions)	December 31, 2009	December 31, 2008
Emission allowances	$ 274	$ 300
Gas, coal and power contracts	296	296
Wind development rights[(a)]	127	161
Other	66	68
Total gross carrying amount	763	825
Accumulated amortization — gas, coal and power contracts	(140)	(117)
Accumulated amortization — wind development rights	(2)	—
Accumulated amortization — other	(28)	(28)
Total accumulated amortization	(170)	(145)
Total intangible assets, net	$ 593	$ 680

(a) As discussed further below and in Note 3, the decrease in wind development rights primarily relates to the sale of certain projects that were acquired as part of Catamount in September 2008.

Emission allowances in the table above include emission allowances acquired by Duke Energy as part of its merger with Cinergy, which were recorded at the then fair value on the date of the merger in April 2006, and emission allowances purchased by Duke Energy. Additionally, Duke Energy is allocated certain zero cost emission allowances on an annual basis. The change in the gross carrying value of emission allowances during the years ended December 31, 2009 and 2008 are as follows:

(in millions)	December 31, 2009	December 31, 2008
Gross carrying value at beginning of period	$ 300	$ 426
Purchases of emission allowances	93	62
Sales and consumption of emission allowances [(a)(b)]	(120)	(116)
Impairment of emission allowances	—	(82)
Other changes	1	10
Gross carrying value at end of period	$ 274	$ 300

(a) Carrying value of emission allowances are recognized via a charge to expense when consumed.
(b) See Note 3 for a discussion of gains and losses on sales of emission allowances by U.S. Franchised Electric and Gas and Commercial Power.

Amortization expense for gas, coal and power contracts, wind development rights and other intangible assets for the years ended December 31, 2009, 2008 and 2007 was approximately $25 million, $27 million and $57 million, respectively.

The table below shows the expected amortization expense for the next five years for intangible assets as of December 31, 2009. The expected amortization expense includes estimates of emission allowances consumption and estimates of consumption of commodities such as gas and coal under existing contracts, as well as estimated amortization related to the wind development projects acquired from Catamount. The amortization amounts discussed below are estimates and actual amounts may differ from these estimates due to such factors as changes in consumption patterns, sales or impairments of emission allowances or other intangible assets, delays in the in-service dates of wind assets, additional intangible acquisitions and other events.

(in millions)	2010	2011	2012	2013	2014
Amortization expense	$136	$38	$34	$31	$30

As discussed in Note 3, Duke Energy completed the acquisition of Catamount in September 2008, resulting in the recognition of approximately $117 million of intangible assets related to wind farm development rights. Of this amount, a portion of the intangible asset value was assigned to projects that Duke Energy disposed of through sale during the year ended December 31, 2009. The intangible assets recorded in connection with the Catamount acquisition primarily represent land use rights and interconnection agreements acquired by Duke Energy as part of the purchase price. Since these intangible assets relate to development projects for which commercial operations have not commenced, amortization of the intangible asset value assigned to each of these projects will not begin until commercial operation is achieved. Duke Energy will evaluate the useful lives of these intangible assets as the projects begin commercial operations, which is anticipated to be in the years 2010 through 2012. Duke Energy currently estimates the useful lives of these projects, once in commercial operation, will be the shorter of the lease term of the land or the estimated lives of the projects, which is approximately 25 years.

In connection with the merger with Cinergy in April 2006, Duke Energy recorded an intangible liability of approximately $113 million associated with the RSP in Ohio, which was recognized in earnings over the regulatory period that ended on December 31, 2008. Duke Energy also recorded approximately $56 million of intangible liabilities associated with other power sale contracts in connection with its merger with Cinergy. The carrying amount of these intangible liabilities associated with other power sale contracts was approximately $10 million and $16 million at December 31, 2009 and 2008, respectively. During the years ended December 31, 2009, 2008 and 2007, Duke Energy amortized approximately $6 million, $73 million and $45 million, respectively, to income related to these intangible liabilities. The remaining balance of approximately $10 million will be amortized to income as follows: approximately $6 million in 2010 and approximately $4 million in 2011. Intangible liabilities are classified as Other within Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Impairment of Emission Allowances.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia issued a decision vacating the Clean Air Interstate Rule (CAIR). Subsequently, in December 2008, a federal appeals court reinstated the CAIR while the EPA develops a new clean air program. See Note 16 for additional information on the CAIR. However, as a result of the July 11, 2008 decision temporarily vacating the CAIR, there were sharp declines in market prices of SO_2 and NO_x allowances in the third quarter of 2008 due to uncertainty associated with future federal requirements to reduce emissions. Accordingly, Duke Energy evaluated the carrying value of emission allowances held by its regulated and unregulated businesses for impairment during the third quarter of 2008.

At the time of its temporary repeal, the CAIR required 50% reductions in SO_2 emissions beginning in 2010 and further 30% reductions in SO_2 emissions in 2015 beyond specified requirements. These reductions were to be achieved by requiring the surrender of SO_2 allowances in a ratio of two allowances per ton of SO_2 emitted beginning in 2010, up from a current one-to-one ratio, escalating to 2.86 allowances per ton of SO_2 emitted beginning in 2015. Taking into account these increases in emission allowance requirements under CAIR, Commercial Power's forecasted SO_2 emissions needed through 2037 exceeded the number of emission allowances held prior to the vacating of the CAIR. Subsequent to the temporary decision to vacate CAIR, Commercial Power determined that it had SO_2 allowances in excess of forecasted emissions and those allowances held in excess of forecasted emissions from future generation required an impairment evaluation. In performing the impairment evaluation for SO_2 allowances at September 30, 2008, management compared quoted market prices for each vintage year allowance to the carrying value of the related allowances in excess of forecasted emissions through 2038. Due to the sharp decline in market prices of SO_2 allowances, as discussed above, Commercial Power recorded pre-tax impairment charges of approximately $77 million related to forecasted excess SO_2 allowances held at September 30, 2008. Additionally, Commercial Power recorded pre-tax impairment charges of approximately $5 million related to annual NO_x allowances during the third quarter of 2008 as these were also affected by the decision to vacate the CAIR. These impairment charges are recorded in Goodwill and Other Impairment Charges within Operating Expenses on the Consolidated Statements of Operations.

Additionally, U.S. Franchised Electric and Gas has emission allowances and certain commitments to purchase emission allowances that, based on management's best estimate at September 30, 2008, resulted in a quantity of emission allowances in excess of the amounts projected to be utilized for operations. The excess emission allowances include forward contracts to purchase SO_2 allowances to cover forecasted shortfalls in emission allowances necessary for operations that were entered into prior to the July 11, 2008 CAIR decision. Prior to the temporary vacating of the CAIR, these forward contracts, which primarily settled in the fourth quarter of 2008 or in 2009, qualified for the NPNS exception within the accounting rules for derivatives. However, since certain of these forward contracts would no longer be considered probable of use in the normal course of operations due to the excess over forecasted needs, in September 2008, U.S. Franchised Electric and Gas determined that these contracts no longer qualified for the NPNS exception. At the time this determination was made, the fair value of the contracts was a liability of approximately $34 million. Since U.S. Franchised Electric and Gas anticipates regulatory recovery of the cost of these emission allowances in normal course, a corresponding regulatory asset was recorded on the Consolidated Balance Sheets. These forward contracts have continued to be marked-to-market, with an offset to the regulatory asset balance, until ultimate settlement.

As a result of the reinstatement of the CAIR in December 2008, as discussed above, all emission allowances and certain commitments to purchase emission allowances held by U.S. Franchised Electric and Gas and Commercial Power are anticipated to be utilized for future emission allowance requirements under the CAIR, unless the EPA develops a new clean air program that changes the existing requirements under the CAIR.

12. INVESTMENTS IN UNCONSOLIDATED AFFILIATES AND RELATED PARTY TRANSACTIONS

Investments in domestic and international affiliates that are not controlled by Duke Energy, but over which it has significant influence, are accounted for using the equity method. Significant investments in affiliates accounted for under the equity method are as follows:

Commercial Power.

As of December 31, 2009 and 2008, investments accounted for under the equity method primarily consist of Duke Energy's approximate 50% ownership interest in the five Sweetwater projects (Phase I-V), which are wind power assets located in Texas that were acquired as part of the acquisition of Catamount, which is further described in Note 3.

International Energy.

As of both December 31, 2009 and 2008, investments accounted for under the equity method primarily include a 25% indirect interest in NMC, which owns and operates a methanol and MTBE business in Jubail, Saudi Arabia, and a 25% indirect interest in Attiki, a natural gas distributor in Athens, Greece.

Duke Energy's wholly-owned subsidiary, CGP Global Greece Holdings S.A. (CGP Greece) has as its only asset the 25% indirect interest in Attiki, and its only third-party liability is a debt obligation that is secured by the 25% indirect interest in Attiki. The debt obligation is also secured by Duke Energy's indirect wholly-owned interest in CGP Greece. This debt obligation of approximately $71 million, which is reflected in Current Maturities of Long-Term Debt on Duke Energy's Consolidated Balance Sheets, is otherwise non-recourse to Duke Energy. In December 2009, Duke Energy decided to abandon its investment in Attiki and the related non-recourse debt. The decision to abandon Attiki was made in part due to the non-strategic nature of the investment and insufficient cash flow from the investee to cover non-recourse debt obligations.

In November 2009, CGP Greece failed to make a scheduled semi-annual installment payment of principal and interest on the debt, and in January 2010 the counterparty to the debt issued a Notice of Event of Default, asserting voting rights and rights to dividends in CGP Greece and thereby its 25% indirect interest in Attiki. As of December 31, 2009, Duke Energy's investment balance in Attiki was approximately $71 million, reflecting an approximate $18 million impairment charge recognized in the fourth quarter of 2009 to reduce the carrying amount of the investment to its estimated fair value.

Other.

As of December 31, 2009 and 2008, investments accounted for under the equity method primarily include telecommunications investments. Additionally, Other includes Duke Energy's effective 50% interest in Crescent which, as discussed further below, has a carrying value of zero.

In connection with the renegotiation of its debt agreements in June 2008, Crescent management modified its existing business strategy to focus some of its efforts on producing near-term cash flows from its non-strategic real estate projects in order to improve liquidity. As a result of its revised business strategy to accelerate certain cash flows resulting from the June 2008 amendments to its debt agreements, Crescent updated its recoverability assessments for its real estate projects as required under the accounting guidance for asset impairments. Under the accounting guidance for asset impairments, the carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. For certain of Crescent's non-strategic assets, it was determined that some projects' projected undiscounted cash flows did not exceed the carrying value of the projects based on the revised business strategy assumptions, and an impairment loss was recorded equal to the amount by which the carrying amount of each impaired project exceeded its estimated fair value. The methods for determining fair value included discounted cash flow models, as well as valuing certain properties based on recent offer prices for bulk-sale transactions and other price data for similar assets. During the year ended December 31, 2008, Crescent recorded impairment charges on certain of its property holdings, primarily in its residential division, of which Duke Energy's proportionate pre-tax share was approximately $238 million. Duke Energy's proportionate share of these impairment charges are recorded in Equity in Earnings (Losses) of Unconsolidated Affiliates in Duke Energy's Consolidated Statements of Operations.

As a result of the impairment charges recorded during the year ended December 31, 2008, the carrying value of Duke Energy's investment in Crescent was reduced to zero. Accordingly, Duke Energy discontinued applying the equity method of accounting to its investment in Crescent during the year ended December 31, 2008 and did not record its proportionate share of any Crescent earnings or losses in subsequent periods.

See Note 17 for a discussion of charges recorded in 2009 related to performance guarantees issued by Duke Energy on behalf of Crescent. Crescent filed Chapter 11 petitions in a U.S. Bankruptcy Court in June 2009.

As of December 31, 2009 and 2008, the carrying amount of investments in affiliates with carrying amounts greater than zero approximated the amount of underlying equity in net assets.

Impairments.

During the years ended December 31, 2009 and 2008, Duke Energy recorded pre-tax impairment charges to the carrying value of investments in unconsolidated affiliates of approximately $21 million and $9 million, respectively. Approximately $18 million of the impairment charge recorded during the year ended December 31, 2009 relates to International Energy's investment in Attiki, as discussed above. These impairment charges, which were recorded in Losses on Sales and Impairments of Unconsolidated Affiliates on the Consolidated Statements of Operations, were recorded as a result of Duke Energy concluding that it would not be able to recover its carrying value in these investments, thus the carrying value of these investments were written down to their estimated fair value.

Investments in Equity Method Unconsolidated Affiliates

	As of:					
	December 31, 2009			December 31, 2008		
(in millions)	Domestic	International	Total	Domestic	International	Total
U.S. Franchised Electric and Gas	$ 4	$ —	$ 4	$ 3	$ —	$ 3
Commercial Power	198	—	198	226	—	226
International Energy[(a)]	—	153	153	—	161	161
Other	71	10	81	73	10	83
Total	$273	$163	$436	$302	$171	$473

(a) As discussed above, International Energy recorded an approximate $18 million pre-tax impairment to write-down the value of its Attiki investment to fair value.

Equity in Earnings (Losses) of Equity Method Unconsolidated Affiliates

	For the Years Ended:								
	December 31, 2009			December 31, 2008			December 31, 2007		
(in millions)	Domestic	International	Total[a]	Domestic	International	Total[a]	Domestic	International	Total[a]
U.S. Franchised Electric and Gas	$(10)	$—	$(10)	$ (16)	$ —	$ (16)	$ (2)	$ —	$ (2)
Commercial Power	7	—	7	16	—	16	17	—	17
International Energy	—	72	72	—	127	127	—	102	102
Other[b]	—	1	1	(230)	1	(229)	38	2	40
Total	$ (3)	$73	$ 70	$(230)	$128	$(102)	$53	$104	$157

(a) Duke Energy's share of net earnings from these unconsolidated affiliates is reflected in the Consolidated Statements of Operations as Equity in Earnings (Losses) of Unconsolidated Affiliates.
(b) Amounts for the year ended December 31, 2008 and 2007 include Duke Energy's proportionate share of impairment charges recorded by Crescent of approximately $238 million and $32 million pre-tax, respectively.

During the years ended December 31, 2009, 2008 and 2007, Duke Energy received distributions from equity investments of approximately $83 million, $195 million and $147 million, respectively, which are included in Other assets within Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows.

Summarized Combined Financial Information of Equity Method Unconsolidated Affiliates

	As of December 31,	
(in millions)	2009	2008
Balance Sheet		
Current assets	$ 1,154	$ 1,399
Non-current assets	2,353	4,072
Current liabilities	(920)	(1,489)
Non-current liabilities	(744)	(2,038)
Net assets	$ 1,843	$ 1,944

	For the Years Ended December 31,		
(in millions)	2009	2008	2007
Income Statement			
Operating revenues	$1,509	$2,683	$2,284
Operating expenses	1,252	2,407	1,634
Net income	257	58	462

Other Investments.

Commercial Power has an interest in South Houston Green Power, L.P. (SHGP), which is a cogeneration facility containing three combustion turbines in Texas City, Texas. Although Duke Energy owned a significant portion of SHGP, it was not consolidated as Duke Energy did not hold a majority voting control or have the ability to exercise control over SHGP, nor was Duke Energy the primary beneficiary. In the fourth quarter of 2008, Duke Energy finalized an asset swap agreement with the other joint venture owner of SHGP, which gives Duke Energy the option to receive either wind assets or a cash settlement, both of which have a value of approximately $180 million and which approximates the carrying value of Duke Energy's investment in SHGP. The cash settlement feature will be utilized if the option to receive the wind assets is not exercised within a nine-month window following the commercialization date of the wind assets. In exchange Duke Energy would surrender its remaining interest in SHGP on the future transaction date. Duke Energy anticipates finalizing this transaction in 2010, either by receiving the wind asset or opting for the cash settlement. This transaction was considered a non-monetary exchange of productive assets with commercial substance for accounting purposes. Duke Energy does not currently expect a significant gain or loss associated with the completion of this transaction.

Effective with the finalization of the asset swap agreement in December 2008, Duke Energy turned over of the operations of SHGP to its equity partner, and Duke Energy's 50% common equity interest in SHGP was converted to a preferred equity interest, which is considered a cost method investment. Commencing on the turnover date and continuing until either the wind asset is transferred to Duke Energy or ultimate cash settlement, Duke Energy will receive a fixed monthly payment in lieu of the economic benefit it would have otherwise received as a common equity member of SHGP. This payment is intended to compensate Duke Energy for normal distributions that it would otherwise be entitled to as an equity owner of SHGP; however, this payment is not economically linked to the actual earnings and operating results of SHGP.

Related Party Transactions.

See Note 21 for information related to Duke Energy Ohio's, Duke Energy Indiana's and Duke Energy Kentucky's sale of receivables to Cinergy Receivables.

Advance SC LLC, which provides funding for economic development projects, educational initiatives, and other programs, was formed during 2004. U.S. Franchised Electric and Gas made donations of approximately $11 million, $11 million and $8 million to the unconsolidated subsidiary during the years ended December 31, 2009, 2008 and 2007, respectively. Additionally, at December 31, 2009 and 2008, U.S. Franchised Electric and Gas had a trade payable to Advance SC LLC of approximately $1 million and $11 million, respectively.

In early 2008, Duke Energy began discussions with Crescent to purchase certain parcels of land in North Carolina and South Carolina that potentially have strategic value to Duke Energy's regulated operations in those states. During the second quarter of 2008, Duke Energy had independent third party appraisals performed for each parcel of land in order to assist in the determination of a potential purchase price. In June 2008, Duke Energy acquired approximately 12,700 acres of land for a purchase price of approximately $51 million. Crescent recorded a gain on the sale. Since Duke Energy is a joint venture owner in Crescent, its proportionate share of the gain was eliminated and instead recorded as a reduction in the carrying amount of the purchased real estate.

Prior to August 2007, International Energy loaned money to Cómpañia de Servicios de Compresión de Campeche, S.A. de C.V. (Campeche) to assist in the costs to build. International Energy received principal and interest payments of approximately $28 million from Campeche during 2007.

Summary Condensed Financial Information

Item 4-08(g) of Regulation S-X requires the presentation of summarized financial information for individual equity method investments that meet certain quantitative thresholds.

Summarized financial information for Crescent has not been presented for the year ended December 31, 2009 since, as discussed above, Duke Energy suspended applying the equity method of accounting to its investment in Crescent in the third quarter of 2008 as its investment in Crescent had been written down to zero. Accordingly, there were no amounts related to the operations of Crescent included in the Consolidated Statements of Operations for the year ended December 31, 2009. Summarized financial information for Crescent for the years ended December 31, 2008 and 2007 is as follows:

(in millions)	Year Ended December 31, 2008	Year Ended December 31, 2007
Operating revenues	$ 407	$536
Operating expenses	$ 754	$415
Operating income	$(347)	$121
Net income[(a)]	$(420)	$ 76

(a) 2008 net income includes the gain recorded by Crescent on the sale of land to Duke Energy that was eliminated by Duke Energy, as discussed further above.

(in millions)	December 31, 2008
Current assets	$ 77
Non-current assets	$ 1,685
Current liabilities	$ 471
Non-current liabilities	$ 1,341
Noncontrolling interest	$ (1)

13. DISCONTINUED OPERATIONS

Income (loss) from discontinued operations was income of approximately $12 million and $16 million for 2009 and 2008, respectively, and a loss of approximately $22 million for 2007. Significant transactions occurring during the years ended December 31, 2008 and 2007 that resulted in discontinued operations presentation are discussed below.

Year Ended December 31, 2008

Commercial Power

In February 2008, Duke Energy entered into an agreement to sell its 480 MW natural gas-fired peaking generating station located near Brownsville, Tennessee to Tennessee Valley Authority for approximately $55 million. This transaction closed in April 2008 and resulted in Duke Energy recognizing an approximate $23 million pre-tax gain at closing.

Year Ended December 31, 2007

Commercial Power

Due to the expiration of certain tax credits, Duke Energy ceased all synthetic fuel (synfuel) operations as of December 31, 2007. Accordingly, the results of operations for synfuel were reclassified to discontinued operations. For the year ended December 31, 2007, synfuel operations had after-tax earnings of approximately $23 million, which includes tax benefits of approximately $84 million.

International Energy

In February 2007, International Energy finalized the approximate $20 million sale of it 50% ownership interest in two hydroelectric power plants near Cochabamba, Bolivia to Econergy International. International Energy recorded an impairment charge in 2006 related to certain assets in Bolivia in connection with this sale. As a result of the sale, International Energy no longer has any assets in Bolivia.

Spin-off of Natural Gas Businesses

As discussed in Note 1, on January 2, 2007, Duke Energy completed the spin-off of Spectra Energy, which principally consisted of Duke Energy's former Natural Gas Transmission business segment and Duke Energy's former 50% ownership interest in DCP Midstream, LLC (DCP Midstream), to Duke Energy shareholders. *Income (Loss) From Discontinued Operations, net of tax*, for the year ended December 31, 2007 includes a pre-tax amount of approximately $18 million related to costs to achieve the Spectra Energy spin-off, primarily fees to outside service providers.

Other Transactions and Balances with Spectra Energy

Effective with the spin-off, Duke Energy and Spectra Energy entered into a Transition Services Agreement (TSA), which expired on December 31, 2007, whereby Duke Energy provided certain support services to Spectra Energy. The amount received by Duke Energy during the year ended December 31, 2007 under this TSA was approximately $15 million. Additionally, as anticipated, Duke Energy has had very limited commercial business activities with Spectra Energy subsequent to the spin-off.

Additionally, effective with the spin-off, Duke Energy and Spectra Energy entered into various reinsurance and other related agreements that allocated certain assets to Spectra Energy and DCP

Midstream created under insurance coverage provided prior to the spin-off by Duke Energy's captive insurance subsidiary and third party reinsurance companies. Under these agreements, Spectra Energy's captive insurance subsidiary reinsured 100% of Duke Energy's retained risk under the insurance coverage provided prior to the spin-off. Consistent with the terms of the reinsurance agreement entered into while all parties were under the common control of Duke Energy, Duke Energy paid approximately $95 million in cash to Spectra Energy's captive insurance company, which was placed in a grantor trust to secure Spectra Energy's obligation to Duke Energy under the Spectra Energy reinsurance agreements. This transfer is reflected in Cash distributed to Spectra Energy within Net cash provided by (used in) financing activities on the Consolidated Statements of Cash Flows. As of December 31, 2009, Duke Energy had a total liability to Spectra Energy and DCP Midstream related to these agreements of approximately $21 million, which is reflected in both Other within Current Liabilities and Other within Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. This liability is offset by a corresponding receivable, of which approximately $4 million was due from Spectra Energy's captive insurance subsidiary under the Spectra Energy reinsurance agreement and approximately $17 million was due from third party reinsurance companies. These amounts are reflected in both Other within Current Assets and Other within Investments and Other Assets in the Consolidated Balance Sheets. In the event any of the reinsurance companies deny coverage for any of the claims covered under these agreements, Duke Energy is not obligated to pay Spectra Energy or DCP Midstream. Further, Duke Energy is providing no insurance coverage to Spectra Energy or DCP Midstream for events which occur subsequent to the spin-off date.

At December 31, 2009 and 2008, Duke Energy had an approximate $50 million and $49 million receivable, respectively, from Spectra Energy related to certain income tax items.

14. PROPERTY, PLANT AND EQUIPMENT

(in millions)	Estimated Useful Life	December 31, 2009	December 31, 2008
	(Years)		
Land	—	$ 725	$ 687
Plant — Regulated			
Electric generation, distribution and transmission[a]	8 – 125	35,983	34,005
Natural gas transmission and distribution	12 – 60	1,694	1,566
Other buildings and improvements[a]	25 –100	617	564
Plant — Unregulated			
Electric generation, distribution and transmission[a]	8 – 100	5,120	3,989
Other buildings and improvements[a]	20 – 90	1,855	1,698
Nuclear fuel	—	1,079	966
Equipment[a]	4 – 33	799	658
Vehicles	5 – 26	77	81
Construction in process	—	5,336	4,379
Other[a]	5 – 33	2,077	1,711
Total property, plant and equipment		55,362	50,304
Total accumulated depreciation — regulated[b], [c]		(15,526)	(14,681)
Total accumulated depreciation — unregulated[c]		(1,886)	(1,587)
Total net property, plant and equipment		$ 37,950	$ 34,036

(a) Includes capitalized leases of approximately $384 million and $208 million at December 31, 2009 and 2008, respectively.
(b) Includes accumulated amortization of nuclear fuel of approximately $603 million and $484 million at December 31, 2009 and 2008, respectively.
(c) Includes aggregate accumulated amortization of capitalized leases of approximately $20 million and $37 million for 2009 and 2008, respectively.

Capitalized interest, which includes the debt component of AFUDC, amounted to approximately $102 million, $93 million and $71 million for 2009, 2008 and 2007, respectively.

DUKE ENERGY CORPORATION

Notes to Consolidated Financial Statements – (Continued)

15. DEBT AND CREDIT FACILITIES

Summary of Debt and Related Terms

(in millions)	Weighted-Average Rate	Year Due	December 31, 2009	December 31, 2008
Unsecured debt	6.1%	2010 – 2037	**$ 7,922**	$ 6,360
Secured debt	3.4%	2010 – 2017	**660**	737
First mortgage bonds[a]	5.7%	2010 – 2040	**5,940**	4,165
Capital leases	6.7%	2010 – 2046	**248**	137
Other debt[b]	1.1%	2010 – 2041	**1,843**	2,084
Notes payable and commercial paper[c][d]	0.4%		**450**	993
Fair value hedge carrying value adjustment			**18**	25
Unamortized debt discount and premium, net			**(66)**	(62)
Total debt[e]			**17,015**	14,439
Current maturities of long-term debt			**(902)**	(646)
Short-term notes payable and commercial paper[f]			**—**	(543)
Total long-term debt			**$16,113**	$13,250

(a) As of December 31, 2009, substantially all of U.S. Franchised Electric and Gas' electric plant in service is mortgaged under the mortgage bond indenture of Duke Energy Carolinas, Duke Energy Ohio and Duke Energy Indiana.
(b) Includes $1,410 million and $1,569 million of Duke Energy tax-exempt bonds as of December 31, 2009 and 2008, respectively. As of December 31, 2009 and 2008, $331 million and $404 million, respectively, was secured by first mortgage bonds and $433 million and $494 million, respectively, was secured by a letter of credit.
(c) Includes $450 million as of both December 31, 2009 and 2008 that was classified as Long-term Debt on the Consolidated Balance Sheets due to the existence of long-term credit facilities which back-stop these commercial paper balances, along with Duke Energy's ability and intent to refinance these balances on a long-term basis. The weighted-average days to maturity was 14 days as of December 31, 2009 and 10 days as of December 31, 2008.
(d) Includes approximately $279 million at December 31, 2008 related to Duke Energy Ohio's drawdown under the master credit facility.
(e) As of December 31, 2009 and 2008, $479 million and $414 million, respectively, of debt was denominated in Brazilian Reals.
(f) Weighted-average rates on outstanding short-term notes payable and commercial paper was 3.4% as of December 31, 2008.

Unsecured Debt.

In September 2009, Duke Energy Kentucky issued $100 million of senior debentures, which carry a fixed interest rate of 4.65% and mature October 1, 2019. Proceeds from the issuance were used to repay Duke Energy Kentucky's borrowings under Duke Energy's master credit facility, to replenish cash used to repay $20 million principal amount of debt due September 15, 2009 and for general corporate purposes.

In August 2009, Duke Energy issued $1 billion principal amount of senior notes, of which $500 million carry a fixed interest rate of 3.95% and mature September 15, 2014 and $500 million carry a fixed interest rate of 5.05% and mature September 15, 2019. Proceeds from the issuance were used to redeem commercial paper, to fund capital expenditures in Duke Energy's unregulated businesses in the U.S. and for general corporate purposes.

In January 2009, Duke Energy issued $750 million principal amount of 6.30% senior notes due February 1, 2014. Proceeds from the issuance were used to redeem commercial paper and for general corporate purposes.

In June 2008, Duke Energy issued $500 million principal amount of senior notes, of which $250 million carry a fixed interest rate of 5.65% and mature June 15, 2013 and $250 million carry a fixed interest rate of 6.25% and mature June 15, 2018. Proceeds from the issuance were used to redeem commercial paper, to fund capital expenditures in Duke Energy's unregulated businesses in the U.S. and for general corporate purposes.

First Mortgage Bonds.

In December 2009, Duke Energy Ohio issued $250 million principal amount of first mortgage bonds, which carry a fixed interest rate of 2.10% and mature June 15, 2013. Proceeds from this issuance, together with cash on hand, were used to repay Duke Energy Ohio's borrowing under Duke Energy's master credit facility. In conjunction with this debt issuance, Duke Energy Ohio entered into an interest rate swap agreement that converted interest on this debt issuance from the fixed coupon rate to a variable rate. The initial variable rate was set at 0.31%.

In November 2009, Duke Energy Carolinas issued $750 million principal amount of first mortgage bonds, which carry a fixed interest rate of 5.30% and mature February 15, 2040. Proceeds from this issuance will be used to fund capital expenditures and general corporate purposes, including the repayment at maturity of $500 million of senior notes and first mortgage bonds in the first half of 2010.

In March 2009, Duke Energy Ohio issued $450 million principal amount of first mortgage bonds, which carry a fixed interest rate of 5.45% and mature April 1, 2019. Proceeds from this issuance were used to repay short-term notes and for general corporate purposes, including funding capital expenditures.

In March 2009, Duke Energy Indiana issued $450 million principal amount of first mortgage bonds, which carry a fixed interest rate of 6.45% and mature April 1, 2039. Proceeds from this issuance were used to fund capital expenditures, to replenish cash used to repay $97 million of senior notes which matured on March 15, 2009, to fund the repayment at maturity of $125 million of first mortgage bonds due July 15, 2009, and for general corporate purposes, including the repayment of short-term notes.

In November 2008, Duke Energy Carolinas issued $900 million principal amount of first mortgage bonds, of which $500 million carry a fixed interest rate of 7.00% and mature November 15, 2018 and $400 million carry a fixed interest rate of 5.75% and mature November 15, 2013. The net proceeds from issuance were used to repay amounts borrowed under the master credit facility, to repay senior notes due January 1, 2009, to replenish cash used to repay senior notes at their scheduled maturity in October 2008 and for general corporate purposes.

In August 2008, Duke Energy Indiana issued $500 million principal amount of first mortgage bonds, which carry a fixed interest rate of 6.35% and mature August 15, 2038. Proceeds from this issuance were used to fund capital expenditures and for general corporate purposes, including the repayment of short-term notes and to redeem first mortgage bonds maturing in September 2008.

In April 2008, Duke Energy Carolinas issued $900 million principal amount of first mortgage bonds, of which $300 million carry a fixed interest rate of 5.10% and mature April 15, 2018 and $600 million carry a fixed interest rate of 6.05% and mature April 15, 2038. Proceeds from the issuance were used to fund capital expenditures and for general corporate purposes. In anticipation of this debt issuance, Duke Energy Carolinas executed a series of interest rate swaps in 2007 to lock in the market interest rates at that time. The value of these interest rate swaps, which were terminated prior to issuance of the fixed rate debt, was a pre-tax loss of approximately $23 million. This amount was recorded as a component of Accumulated Other Comprehensive Loss and is being amortized as a component of Interest Expense over the life of the debt.

In January 2008, Duke Energy Carolinas issued $900 million principal amount of first mortgage bonds, of which $400 million carry a fixed interest rate of 5.25% and mature January 15, 2018 and $500 million carry a fixed interest rate of 6.00% and mature January 15, 2038. Proceeds from the issuance were used to fund capital expenditures and for general corporate purposes, including the repayment of commercial paper. In anticipation of this debt issuance, Duke Energy Carolinas executed a series of interest rate swaps in 2007 to lock in the market interest rates at that time. The value of these interest rate swaps, which were terminated prior to issuance of the fixed rate debt, was a pre-tax loss of approximately $18 million. This amount was recorded as a component of Accumulated Other Comprehensive Loss and is being amortized as a component of Interest Expense over the life of the debt.

Other Debt.

In October 2009, Duke Energy Indiana refunded $50 million of tax-exempt variable-rate demand bonds through the issuance of $50 million principal amount of tax-exempt term bonds, which carry a fixed interest rate of 4.95% and mature October 1, 2040. The tax-exempt bonds are secured by a series of Duke Energy Indiana's first mortgage bonds.

In September 2009, Duke Energy Carolinas converted $77 million of tax-exempt variable-rate demand bonds to tax-exempt term bonds, which carry a fixed interest rate of 3.60% and mature February 1, 2017. In connection with the conversion, the tax-exempt bonds were secured by a series of Duke Energy Carolinas' first mortgage bonds.

In June 2009, Duke Energy Indiana refunded $55 million of tax-exempt variable-rate demand bonds through the issuance of $55 million principal amount of tax-exempt term bonds due August 1, 2039, which carry a fixed interest rate of 6.00% and are secured by a series of Duke Energy Indiana's first mortgage bonds. The refunded bonds were redeemed July 1, 2009.

In January 2009, Duke Energy Indiana refunded $271 million of tax-exempt auction rate bonds through the issuance of $271 million of tax-exempt variable-rate demand bonds, which are supported by direct-pay letters of credit, of which $144 million had initial rates of 0.7% reset on a weekly basis with $44 million maturing May 2035, $23 million maturing March 2031 and $77 million maturing December 2039. The remaining $127 million had initial rates of 0.5% reset on a daily basis with $77 million maturing December 2039 and $50 million maturing October 2040.

In December 2008, Duke Energy Kentucky refunded $50 million of tax-exempt auction rate bonds through the issuance of $50 million of tax-exempt variable-rate demand bonds, which are supported by a direct-pay letter of credit. The variable-rate demand bonds, which are due August 1, 2027, had an initial interest rate of 0.65% which is reset on a weekly basis.

In October 2008, International Energy issued approximately $153 million of debt in Brazil, of which approximately $112 million mature in September 2013 and carry a variable interest rate equal to the Brazil interbank rate plus 2.15%, and approximately $41 million mature in September 2015 and carry a fixed interest rate of 11.6% plus an annual inflation index. International Energy used these proceeds to pre-pay existing long-term debt balances.

In April 2008, Duke Energy Carolinas refunded $100 million of tax-exempt auction rate bonds through the issuance of $100 million of tax-exempt variable-rate demand bonds, which are supported by a direct-pay letter of credit. The variable-rate demand bonds, which are due November 1, 2040, had an initial interest rate of 2.15% which will be reset on a weekly basis.

Auction Rate Debt.

As of December 31, 2009, Duke Energy had auction rate tax-exempt bonds outstanding of approximately $461 million. While these debt instruments are long-term in nature and cannot be put back to Duke Energy prior to maturity, the interest rates on these instruments are designed to reset periodically through an auction process. In February 2008, Duke Energy began to experience failed auctions for these debt instruments. When failed auctions occur on a series of this debt, Duke Energy is required to begin paying a failed-auction interest rate on the instrument. The failed-auction interest rate for the majority of the auction rate debt is 2.0 times one-month London Interbank Offered Rate (LIBOR). Payment of the failed-auction interest rates will continue until Duke Energy is able to either successfully remarket these instruments through the auction process, or refund and refinance the existing debt. While Duke Energy has plans to refund and refinance its remaining auction rate tax-exempt bonds, the timing of such refinancing activities is uncertain and subject to market conditions. If Duke Energy is unable to successfully refund and refinance these debt instruments, the impact of paying higher interest rates on the outstanding auction rate debt is not expected to materially affect Duke Energy's overall financial position, results of operations or cash flows.

Convertible Senior Notes.

In May 2003, Duke Energy issued approximately $770 million of 1.75% convertible senior notes that were convertible into Duke Energy common stock at a premium of 40% above the May 1, 2003 closing common stock market price of $16.85 per share. The conversion of these senior notes into shares of Duke Energy common stock was contingent upon the occurrence of certain events during specified periods. During 2006, Duke Energy issued shares of common stock to settle a portion of the convertible senior notes. In May 2007, pursuant to the terms of the debt agreement, substantially all of the holders of the Duke Energy convertible senior notes required Duke Energy to repurchase the then outstanding balance of approximately $110 million at a price equal to 100% of the principal amount plus accrued interest.

In connection with the spin-off of Spectra Energy on January 2, 2007 (see Note 1), Duke Energy distributed approximately 2 million shares of Spectra Energy common stock to the holders of the convertible senior notes pursuant to the antidilution provisions of the indenture agreement, resulting in a pre-tax charge of approximately $21 million during the three months ended March 31, 2007, which is recorded in Other Income and Expenses, net in the Consolidated Statements of Operations.

Accounts Receivable Securitization.

Duke Energy securitizes certain accounts receivable through Duke Energy Receivables Finance Company, LLC (DERF), a bankruptcy remote, special purpose subsidiary. DERF is a wholly-owned limited liability company with a separate legal existence from its parent, and its assets are not intended to be generally available to creditors of Duke Energy. As a result of the securitization, on a daily basis Duke Energy sells certain accounts receivable, arising from the sale of electricity and/or related services as part of Duke Energy's franchised electric business, to DERF. In order to fund its purchases of accounts receivable, DERF has a $300 million secured credit facility with a commercial paper conduit administered by Citibank, N.A., which terminates in September 2011. The credit facility and related securitization documentation contain several covenants, including covenants with respect to the accounts receivable held by DERF, as well as a covenant requiring that the ratio of Duke Energy consolidated indebtedness to Duke Energy consolidated capitalization not exceed 65%. As of December 31, 2009 and 2008, the interest rate associated with the credit facility, which is based on commercial paper rates, was 1.6% and 3.3%, respectively, and $300 million was outstanding under the credit facility as of both December 31, 2009 and 2008. The securitization transaction was not structured to meet the criteria for sale accounting treatment under the accounting guidance for transfers and servicing of financial assets and, accordingly, is reflected as a secured borrowing in the Consolidated Balance Sheets. As of December 31, 2009 and 2008, the $300 million outstanding balance of the credit facility was secured by approximately $556 million and $518 million, respectively, of accounts receivable held by DERF. The obligations of DERF under the credit facility are non-recourse to Duke Energy. DERF meets the accounting definition of a VIE and is subject to the new accounting rules for consolidation and transfers of financial assets effective January 1, 2010; however, the new accounting rules will not result in a substantial change to the accounting for DERF. See Note 21 for further information on VIEs.

Floating Rate Debt.

Unsecured debt, secured debt and other debt included approximately $2.8 billion and $3.2 billion of floating-rate debt as of December 31, 2009 and 2008, respectively, which excludes approximately $336 million and $300 million of Brazilian debt at December 31, 2009 and 2008, respectively, that is indexed annually to Brazilian inflation. Floating-rate debt is primarily based on commercial paper rates or a spread relative to an index such as LIBOR for debt denominated in U.S. dollars. As of December 31, 2009 and 2008, the average interest rate associated with floating-rate debt was approximately 1.5% and 3.2%, respectively.

Maturities, Call Options and Acceleration Clauses.

Annual Maturities as of December 31, 2009

(in millions)	
2010	$ 902
2011	602
2012	2,247
2013	1,443
2014	1,398
Thereafter	10,423
Total long-term debt, including current maturities	$17,015

Duke Energy has the ability under certain debt facilities to call and repay the obligation prior to its scheduled maturity. Therefore, the actual timing of future cash repayments could be materially different than the above as a result of Duke Energy's ability to repay these obligations prior to their scheduled maturity.

Duke Energy may be required to repay certain debt should the credit ratings at Duke Energy Carolinas fall to a certain level at Standard & Poor's (S&P) or Moody's Investors Service (Moody's). As of December 31, 2009, Duke Energy had approximately $6 million of senior unsecured notes which mature serially through 2012 that may be required to be repaid if Duke Energy Carolinas' senior unsecured debt ratings fall below BBB- at S&P or Baa3 at Moody's, and $16 million of senior unsecured notes which mature serially through 2016 that may be required to be repaid if Duke Energy Carolinas' senior unsecured debt ratings fall below BBB at S&P or Baa2 at Moody's. As of February 1, 2010, Duke Energy Carolinas' senior unsecured credit rating was A- at S&P and A3 at Moody's.

Available Credit Facilities.

The total capacity under Duke Energy's master credit facility, which expires in June 2012, is approximately $3.14 billion. The credit facility contains an option allowing borrowing up to the full amount of the facility on the day of initial expiration for up to one year. Duke Energy and its wholly-owned subsidiaries, Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky (collectively referred to as the borrowers), each have borrowing capacity under the master credit facility up to specified sub limits for each borrower. However, Duke Energy has the unilateral ability to increase or decrease the borrowing sub limits of each borrower, subject to per borrower maximum cap limitations, at any time. See footnote (c) to the table below for the borrowing sub limits for each of the borrowers as of December 31, 2009. The amount available under the master credit facility has been reduced by draw downs of cash and the use of the master credit facility to backstop the issuances of commercial paper, letters of credit and certain tax-exempt bonds.

Master Credit Facility Summary as of December 31, 2009 (in millions)[a]

	Credit Facility Capacity	Commercial Paper	Draw Down on Credit Facility	Letters of Credit	Tax-Exempt Bonds	Total Amount Utilized	Available Credit Facility Capacity
Duke Energy Corporation							
$3,137 multi-year syndicated[b][c]	$3,137	$450	$397	$121	$285	$1,253	$1,884

(a) This summary excludes certain demand facilities and committed facilities that are insignificant in size or which generally support very specific requirements, which primarily include facilities that backstop various outstanding tax-exempt bonds.
(b) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65% for each borrower.
(c) Contains sub limits at December 31, 2009 as follows: $1,097 million for Duke Energy, $840 million for Duke Energy Carolinas, $650 million for Duke Energy Ohio, $450 million for Duke Energy Indiana and $100 million for Duke Energy Kentucky.

In September 2008, Duke Energy and its wholly-owned subsidiaries, Duke Energy Carolinas, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky, borrowed a total of approximately $1 billion under Duke Energy's master credit facility. The following borrowings under Duke Energy's master credit facility remained outstanding at December 31, 2009:

(in millions)	Amounts Borrowed Under Master Credit Facility
Duke Energy Corporation	$274
Duke Energy Indiana	123
Total	$397

The loans under the master credit facility are revolving credit loans that currently bear interest at one-month LIBOR plus an applicable spread ranging from 19 to 23 basis points. The loan for Duke Energy has a stated maturity of June 2012, while the loans for all of the other borrowers had stated maturities of September 2009; however, the borrowers have the ability under the master credit facility to renew the loans due in September 2009 on an annual basis up through the date the master credit facility matures in June 2012. As a result of these annual renewal provisions, in September 2009, Duke Energy Ohio and Duke Energy Indiana repaid and immediately re-borrowed approximately $279 million and $123 million, respectively, under the master credit facility. Duke Energy Indiana has the intent and ability to refinance these obligations on a long-term basis, either through renewal of the terms of the loan through the master credit facility, which has non-cancelable terms in excess of one-year, or through issuance of long-term debt to replace the amounts drawn under the master credit facility. Accordingly, total borrowings by Duke Energy Indiana of $123 million are reflected as Long-Term Debt on the Consolidated Balance Sheets at both December 31, 2009 and 2008. Additionally, Duke Energy Kentucky's borrowings of $74 million, which was repaid in 2009 through funds obtained from the issuance of long-term debt as discussed above, was included in Long-Term Debt on the Consolidated Balance Sheets at December 31, 2008. Duke Energy Ohio's borrowing under the master credit facility was repaid in the fourth quarter of 2009, as discussed above. As Duke Energy Ohio did not have the intent to refinance its borrowings on a long-term basis, amounts outstanding at December 31, 2008 of $279 million were reflected in Notes Payable and Commercial Paper within Current Liabilities on the Consolidated Balance Sheets.

At December 31, 2009 and 2008, approximately $706 million and $779 million, respectively, of tax-exempt bonds were classified as Long-Term Debt on the Consolidated Balance Sheets. Of this amount, the master credit facility served as a backstop for approximately $385 million of these pollution control bonds (of which approximately $100 million is in the form of letters of credit), with the remaining balance backstopped by other specific long-term credit facilities separate from the master credit facility. Additionally, at both December 31, 2009 and 2008, approximately $450 million of commercial paper issuances were classified as Long-Term Debt on the Consolidated Balance Sheets. These tax-exempt bonds and commercial paper issuances, which are short-term obligations by nature, are classified as long-term due to Duke Energy's intent and ability to utilize such borrowings as long-term financing. As Duke Energy's master credit facility and other specific purpose credit facilities have non-cancelable terms in excess of one year as of the balance sheet date, Duke Energy has the ability to refinance these short-term obligations on a long-term basis.

In September 2008, Duke Energy Indiana and Duke Energy Kentucky collectively entered into a $330 million three-year letter of credit agreement with a syndicate of banks, under which Duke Energy Indiana and Duke Energy Kentucky may request the issuance of letters of credit up to $279 million and $51 million, respectively, on their behalf to support various series of variable rate demand bonds issued or to be issued on behalf of either Duke Energy Indiana or Duke Energy Kentucky. This credit facility, which is not part of Duke Energy's master credit facility, may not be used for any purpose other than to support the variable rate demand bonds issued by Duke Energy Indiana and Duke Energy Kentucky.

Restrictive Debt Covenants.

Duke Energy's debt and credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2009, Duke Energy was in compliance with all covenants related to its significant debt agreements. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or the acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

Other Loans.

During 2009 and 2008, Duke Energy had loans outstanding against the cash surrender value of the life insurance policies that it owns on the lives of its executives. The amounts outstanding were $411 million as of December 31, 2009 and $384 million as of December 31, 2008. The amounts outstanding were carried as a reduction of the related cash surrender value that is included in Other within Investments and Other Assets on the Consolidated Balance Sheets.

16. COMMITMENTS AND CONTINGENCIES

General Insurance

Duke Energy carries insurance and reinsurance coverage either directly or through its captive insurance company, Bison, and its affiliates, consistent with companies engaged in similar commercial operations with similar type properties. Duke Energy's insurance coverage includes (i) commercial general public liability insurance for liabilities arising to third parties for bodily injury and property damage resulting from Duke Energy's operations; (ii) workers' compensation liability coverage to statutory limits; (iii) automobile liability insurance for all owned, non-owned and hired vehicles covering liabilities to third parties for bodily injury and property damage; (iv) insurance policies in support of the indemnification provisions of Duke Energy's by-laws and (v) property insurance covering the replacement value of all real and personal property damage, excluding electric transmission and distribution lines, including damages arising from boiler and machinery breakdowns, earthquake, flood damage and extra expense. All coverage is subject to certain deductibles or retentions, sublimits, terms and conditions common for companies with similar types of operations.

In 2006, Bison was a member of sEnergy Insurance Limited (sEnergy), which provided business interruption reinsurance coverage for Duke Energy's non-nuclear facilities. Duke Energy accounted for these memberships under the cost method, as it did not have the ability to exert significant influence over these investments. sEnergy ceased insuring events subsequent to May 15, 2006, and is currently winding down its operations and settling its outstanding claims. Bison will continue to pay additional premiums to sEnergy as it settles its outstanding claims during its wind-down; however, Duke Energy does not anticipate that the payments associated with the settlement of these outstanding claims will have a material impact on its consolidated results of operations, cash flows or financial position.

Duke Energy also maintains excess liability insurance coverage above the established primary limits for commercial general liability and automobile liability insurance. Limits, terms, conditions and deductibles are comparable to those carried by other energy companies of similar size.

The cost of Duke Energy's general insurance coverage can fluctuate year to year reflecting the changing conditions of the insurance markets.

Nuclear Insurance

Duke Energy Carolinas owns and operates the McGuire and Oconee Nuclear Stations and operates and has a partial ownership interest in the Catawba Nuclear Station. The McGuire and Catawba

Nuclear Stations have two nuclear reactors each and Oconee has three. Nuclear insurance includes: nuclear liability coverage; property, decontamination and premature decommissioning coverage; and business interruption and/or extra expense coverage. The other joint owners of the Catawba Nuclear Station reimburse Duke Energy Carolinas for certain expenses associated with nuclear insurance premiums. The Price-Anderson Act requires Duke Energy to provide for public liability claims resulting from nuclear incidents to the maximum total financial protection liability, which was approximately $12.5 billion and increased to approximately $12.6 billion effective January 1, 2010.

Primary Liability Insurance.

Duke Energy has purchased the maximum reasonably available private primary liability insurance as required by law, which was $300 million and increased to $375 million effective January 1, 2010.

Excess Liability Program.

This program provides approximately $12.2 billion of coverage through the Price-Anderson Act's mandatory industry-wide excess secondary financial protection program of risk pooling. The $12.2 billion is the sum of the current potential cumulative retrospective premium assessments of $117.5 million per licensed commercial nuclear reactor. This would be increased by $117.5 million for each additional commercial nuclear reactor licensed, or reduced by $117.5 million for nuclear reactors no longer operational and may be exempted from the risk pooling program. Under this program, licensees could be assessed retrospective premiums to compensate for public liability damages in the event of a nuclear incident at any licensed facility in the U.S. If such an incident should occur and public liability damages exceed primary liability insurance, licensees may be assessed up to $117.5 million for each of their licensed reactors, payable at a rate not to exceed $17.5 million a year per licensed reactor for each incident. The assessment and rate are subject to indexing for inflation and may be subject to state premium taxes. The Price-Anderson Act provides for an inflation adjustment at least every five years with the last adjustment effective October 2008.

Duke Energy is a member of Nuclear Electric Insurance Limited (NEIL), which provides property and accidental outage insurance coverage for Duke Energy's nuclear facilities under three policy programs:

Primary Property Insurance.

This policy provides $500 million of primary property damage coverage for each of Duke Energy's nuclear facilities.

Excess Property Insurance.

This policy provides excess property, decontamination and decommissioning liability insurance: $2.25 billion for the Catawba Nuclear Station and $1.0 billion each for the Oconee and McGuire Nuclear Stations. The Oconee and McGuire Nuclear Stations also share an additional $1.0 billion insurance limit above this excess. This shared limit is not subject to reinstatement in the event of a loss.

Accidental Outage Insurance.

This policy provides business interruption and/or extra expense coverage resulting from an accidental outage of a nuclear unit. Each McGuire and Catawba unit is insured for up to $3.5 million per week, and the Oconee units are insured for up to $2.8 million per week. Coverage amounts decline if more than one unit is involved in an accidental outage. Initial coverage begins after a 12-week deductible period for Catawba and a 26-week deductible period for McGuire and Oconee and continues at 100% for 52 weeks and 80% for the next 110 weeks. The McGuire and Catawba policy limit is $490 million and the Oconee policy limit is $392 million.

In the event of large industry losses, NEIL's Board of Directors may assess Duke Energy for amounts up to 10 times its annual premiums. The current potential maximum assessments are: Primary Property Insurance — $37 million, Excess Property Insurance — $43 million and Accidental Outage Insurance — $22 million.

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 a qualifying accident, and second, to decontaminate before any proceeds can be used for decommissioning, plant repair or restoration.

In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered by other sources, could have a material adverse effect on Duke Energy's results of operations, cash flows or financial position.

The maximum assessment amounts include 100% of Duke Energy's potential obligation to NEIL for the Catawba Nuclear Station. However, the other joint owners of the Catawba Nuclear Station are obligated to assume their pro rata share of liability for retrospective premiums and other premium assessments resulting from the Price-Anderson Act's excess secondary financial protection program of risk pooling, or the NEIL policies.

Environmental

Duke Energy is subject to international, federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. These regulations can be changed from time to time, imposing new obligations on Duke Energy.

Remediation Activities.

Duke Energy and its affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of ongoing Duke Energy operations, sites formerly owned or used by Duke Energy entities, and sites owned by third parties. Remediation typically involves management of contaminated soils and may involve groundwater remediation. Managed in conjunction with relevant federal, state and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, Duke Energy or its affiliates could potentially be held responsible for contamination caused by other parties. In some instances, Duke Energy may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. All of these sites generally are managed in the normal course of business or affiliate operations. During 2009, Duke Energy recorded additional reserves associated with remediation activities at certain manufactured gas plant sites and it is anticipated that additional costs associated with remediation activities at certain of its sites will be incurred in the future.

Included in Other within Deferred Credits and Other Liabilities and Other within Current Liabilities on the Consolidated Balance Sheets were total accruals related to extended environmental-related activities of approximately $65 million and $55 million as of December 31, 2009 and December 31, 2008, respectively. These accruals represent Duke Energy's provisions for costs associated with remediation activities at some of its current and former sites, as well as other relevant environmental contingent liabilities. Management, in the normal course of business, continually assesses the nature and extent of known or potential environmental-related contingencies and records liabilities when losses become probable and are reasonably estimable. Costs associated with remediation activities within Duke Energy's regulated operations are typically expensed unless recovery of the costs is deemed probable.

Clean Water Act 316(b).

The EPA finalized its cooling water intake structures rule in July 2004. The rule established aquatic protection requirements for existing facilities that withdraw 50 million gallons or more of water per day from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters for cooling purposes. Fourteen of the 23 coal and nuclear-fueled generating facilities in which Duke Energy is either a whole or partial owner are affected sources under that rule. On April 1, 2009, the U.S. Supreme Court ruled in favor of the appellants that the EPA may consider costs when determining which technology option each site should implement. Depending on how the cost-benefit analysis is incorporated into the revised EPA rule, the analysis could narrow the range of technology options required for each of the 14 affected facilities. Because of the wide range of potential outcomes, Duke Energy is unable to estimate its costs to comply at this time.

Clean Air Interstate Rule (CAIR).

The EPA finalized its CAIR in May 2005. The CAIR limits total annual and summertime NO_x emissions and annual SO_2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. Phase 1 began in 2009 for NO_x and begins in 2010 for SO_2. Phase 2 begins in 2015 for both NO_x and SO_2. On March 25, 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) heard oral argument in a case involving multiple challenges to the CAIR. On July 11, 2008, the D.C. Circuit issued its decision in *North Carolina v. EPA* No. 05-1244 vacating the CAIR. The EPA filed a petition for rehearing on September 24, 2008 with the D.C. Circuit asking the court to reconsider various parts of its ruling vacating the CAIR. In December 2008, the D.C. Circuit issued a decision remanding the CAIR to the EPA without vacatur. The EPA must now conduct a new rulemaking to modify the CAIR in accordance with the court's July 11, 2008 opinion. This decision means that the CAIR as initially finalized in 2005 remains in effect until the new EPA rule takes effect. The EPA has indicated that it currently plans on issuing a proposed rule in the April-May 2010 timeframe. It is uncertain how long the current CAIR will remain in effect or how the new rulemaking will alter the CAIR.

The emission controls Duke Energy is installing to comply with state specific clean air legislation will contribute significantly to achieving compliance with the CAIR requirements. Additionally, Duke Energy plans to spend approximately $75 million between 2010 and 2014 (approximately $65 million in Ohio and $10 million in Indiana) to comply with Phase 1 of the CAIR. Duke Energy is currently unable to estimate the costs to comply with any new rule the EPA will issue in the future as a result of the D.C. District Court's December 2008 decision discussed above. The IURC issued an order in 2006 granting Duke Energy Indiana approximately $1.07 billion in rate recovery to cover its estimated Phase 1 compliance costs of the CAIR and the Clean Air Mercury Rule in Indiana. Duke Energy Ohio will recover most of the depreciation and financing costs related to environmental compliance projects for 2009-2011 through its ESP.

Coal Combustion Product (CCP) Management.

Duke Energy currently estimates that it will spend approximately $373 million over the period 2010-2014 to install synthetic caps and liners at existing and new CCP landfills and to convert some of its CCP handling systems from wet to dry systems. The EPA and a number of states are considering additional regulatory measures that will contain specific and more detailed requirements for the management and disposal of coal combustion products, primarily ash, from Duke Energy's coal-fired power plants. The EPA has indicated that it intends to propose a rule early in 2010. Additional laws and regulations under consideration which more stringently regulate coal ash, including the potential regulation of coal ash as hazardous waste, will likely increase costs for Duke Energy's coal facilities. Duke Energy is unable to estimate its potential costs at this time.

Litigation

New Source Review (NSR).

In 1999-2000, the U.S. Department of Justice (DOJ), acting on behalf of the EPA and joined by various citizen groups and states, filed a number of complaints and notices of violation against multiple utilities across the country for alleged violations of the NSR provisions of the Clean Air Act (CAA). Generally, the government alleges that projects performed at various coal-fired units were major modifications, as defined in the CAA, and that the utilities violated the CAA when they undertook those projects without obtaining permits and installing the best available emission controls for SO_2, NO_x and particulate matter. The complaints seek injunctive relief to require installation of pollution control technology on various generating units that allegedly violated the CAA, and unspecified civil penalties in amounts of up to $32,500 per day for each violation. A number of Duke Energy's plants have been subject to these allegations. Duke Energy asserts that there were no CAA violations because the applicable regulations do not require permitting in cases where the projects undertaken are "routine" or otherwise do not result in a net increase in emissions.

In 2000, the government brought a lawsuit against Duke Energy in the U.S. District Court in Greensboro, North Carolina. The EPA claims that 29 projects performed at 25 of Duke Energy's coal-fired units in the Carolinas violate these NSR provisions. Three environmental groups have intervened in the case. In August 2003, the trial court issued a summary judgment opinion adopting Duke Energy's legal positions on the standard to be used for measuring an increase in emissions, and granted judgment in favor of Duke Energy. The trial court's decision was appealed and ultimately reversed and remanded for trial by the U.S. Supreme Court. At trial, Duke Energy will continue to assert that the projects were routine or not projected to increase emissions. No trial date has been set.

In November 1999, the U.S. brought a lawsuit in the U.S. Federal District Court for the Southern District of Indiana against Cinergy, Duke Energy Ohio, and Duke Energy Indiana alleging various violations of the CAA for various projects at six Duke Energy owned and co-owned generating stations in the Midwest. Three northeast states and two environmental groups have intervened in the case. A jury trial commenced on May 5, 2008 and jury verdict was returned on May 22, 2008. The jury found in favor of Cinergy, Duke Energy Ohio and Duke Energy Indiana on all but three units at Wabash River. Additionally, the plaintiffs had claimed that Duke Energy violated an Administrative Consent Order entered into in 1998 between the EPA and Cinergy relating to alleged violations of Ohio's State Implementation Plan provisions governing particulate matter at Duke Energy Ohio's W.C. Beckjord Station.

A remedy trial for violations previously established at the Wabash River and W.C. Beckjord Stations was held during the week of February 2, 2009. On May 29, 2009, the court issued its remedy ruling and ordered the following relief: (i) Wabash River Units 2, 3 and 5 to be permanently retired by September 30, 2009; (ii) surrender of SO_2 allowances equal to the emissions from Wabash River Units 2, 3 and 5 from May 22, 2008 through September 30, 2009; (iii) civil penalty in the amount of $687,500 for Beckjord violations; and (iv) installation of a particulate continuous emissions monitoring system at the W.C. Beckjord Station Units 1 and 2. The civil penalty has been paid. On September 22, 2009, defendants filed a notice of appeal with the Seventh Circuit Court of Appeals of the judgment relating to Wabash River Units 2, 3 and 5. That appeal is still pending. As of September 30, 2009, Wabash River Units 2, 3 and 5 have been retired. On October 21, 2008, Plaintiffs filed a motion for a new liability trial claiming that defendants misled the plaintiffs and the jury by, among other things, not disclosing a consulting agreement with a fact witness and by referring to that witness as "retired" during the liability trial when in fact he was working for Duke Energy under the referenced consulting agreement in connection with the trial. On December 18, 2008, the court granted plaintiffs' motion for a new liability trial on claims for which Duke Energy was not previously found liable. That new trial commenced on May 11, 2009. On May 19, 2009, the jury announced its verdict finding in favor of Duke Energy on four of the remaining six projects at issue. The two projects in which the jury found violations were undertaken at Units 1 and 3 of the Gallagher Station in Indiana. A remedy trial on those two violations was scheduled to commence on January 25, 2010; however, the parties reached a negotiated agreement on those issues and filed a proposed consent decree with the court on December 22, 2009 for public comment and approval. The substantive terms of the proposed consent decree require: (i) conversion of Gallagher units 1 and 3 to natural gas combustion by 2013; (ii) installation of additional pollution controls at Gallagher units 2 and 4 by 2011; and (iii) additional environmental projects, payments and penalties. Duke Energy estimates that these and other actions in the settlement will cost at least $88 million. The parties anticipate that the court will approve and enter the consent decrees in due course.

On April 3, 2008, the Sierra Club filed another lawsuit in the U.S. District Court for the Southern District of Indiana against Duke Energy Indiana and certain affiliated companies alleging CAA violations at the Edwardsport power station. On June 30, 2008, defendants filed a motion to dismiss, or alternatively to stay, this litigation on jurisdictional grounds. The District Court denied that motion. The defendants subsequently filed a motion for summary judgment alleging that the applicable statute of limitations bars all of plaintiffs' claims. Plaintiffs filed two motions for partial summary judgment requesting rulings on the applicability of certain legal standards. On January 26, 2010, the parties filed a joint motion to stay all proceedings and deadlines pending the court's ruling on the motions for summary judgment. On February 2, 2010, the motion to stay was granted, although the trial is still set to commence on January 10, 2011.

On July 31, 2009, the EPA served a request for information under section 114 of the CAA on Duke Energy, Duke Energy Ohio and Duke Energy Business Services, Inc., requesting information pertaining to various maintenance projects and emissions and operations data relevant to the Miami Fort and W.C. Beckjord stations in Ohio. Duke Energy's objections and responses to the EPA's section 114 request were filed on September 28, 2009 and Duke Energy continues to provide information to the EPA.

It is not possible to estimate the damages, if any, that Duke Energy might incur in connection with the unresolved matters discussed above. Ultimate resolution of these matters relating to NSR, even in settlement, could have a material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position. However, Duke Energy will pursue appropriate regulatory treatment for any costs incurred in connection with such resolution.

Duke Energy Carolinas' Cliffside Unit 6 Permit.

On July 16, 2008, the Southern Alliance for Clean Energy, Environmental Defense Fund, National Parks Conservation Association, Natural Resources Defenses Council, and Sierra Club (collectively referred to as Citizen Groups) filed suit in federal court alleging that Duke Energy Carolinas violated the CAA when it commenced construction of Cliffside Unit 6 at Cliffside Steam Station in Rutherford County, North Carolina without obtaining a determination that the MACT emission limits will be met for all prospective hazardous air emissions at that plant. The Citizen Groups claim the right to injunctive relief against further construction at the plant as well as civil penalties in the amount of up to $32,500 per day for each alleged violation. In July 2008, Duke Energy Carolinas voluntarily performed a MACT assessment of air emission controls planned for Cliffside Unit 6 and submitted the results to the DENR. On August 8, 2008 the plaintiffs filed a motion for summary judgment. On December 2, 2008, the Court granted summary judgment in favor of the Plaintiffs and entered judgment ordering Duke Energy Carolinas to initiate a MACT process before the DAQ. The court did not order an injunction against further construction, but retained jurisdiction to monitor the MACT proceedings. On December 4, 2008, Duke Energy Carolinas submitted its MACT filing and supporting information to the DAQ specifically seeking DAQ's concurrence as a threshold matter that construction of Cliffside Unit 6 is not a major source subject to section 112 of the CAA and submitting a MACT determination application. Concurrent with the initiation of the MACT process, Duke Energy Carolinas filed a notice of appeal to the Fourth Circuit Court of Appeals of the Court's December 2, 2008 order to reverse the Court's determination that Duke Energy Carolinas violated the CAA. The DAQ issued the revised permit on March 13, 2009, as discussed above. Based upon DAQ's minor-source determination, Duke Energy Carolinas filed a motion requesting that the court abstain from further action on the matter and dismiss the plaintiffs' complaint. The court granted Duke Energy Carolinas motion to abstain and dismissed the plaintiffs' complaint without prejudice. On August 3, 2009, plaintiffs filed a notice of appeal of the court's order and Duke Energy Carolinas likewise appealed on the grounds, among others, that the dismissal should have been with prejudice to any future filing.

It is not possible to predict with certainty whether Duke Energy Carolinas will incur any liability or to estimate the damages, if any, that Duke Energy Carolinas might incur in connection with this matter. To the extent that a court of proper jurisdiction halts construction of the plant, Duke Energy Carolinas will seek to meet customers' needs for power through other resources. In addition, Duke Energy Carolinas will seek appropriate regulatory treatment for the investment in the plant.

Carbon Dioxide (CO_2) Litigation.

In July 2004, the states of Connecticut, New York, California, Iowa, New Jersey, Rhode Island, Vermont, Wisconsin and the City of New York brought a lawsuit in the U.S. District Court for the Southern District of New York against Cinergy, American Electric Power Company, Inc., American Electric Power Service Corporation, The Southern Company, Tennessee Valley Authority, and Xcel Energy Inc. A similar lawsuit was filed in the U.S. District Court for the Southern District of New York against the same companies by Open Space Institute, Inc., Open Space Conservancy, Inc., and The Audubon Society of New Hampshire. These lawsuits allege that the defendants' emissions of CO_2 from the combustion of fossil fuels at electric generating facilities contribute to global warming and amount to a public nuisance. The complaints also allege that the defendants could generate the same amount of electricity while emitting significantly less CO_2. The plaintiffs are seeking an injunction requiring each defendant to cap its CO_2 emissions and then reduce them by a specified percentage each year for at least a decade. In September 2005, the District Court granted the defendants' motion to dismiss the lawsuit. The plaintiffs have appealed this ruling to the Second Circuit Court of Appeals. Oral arguments were held before the Second Circuit Court of Appeals on June 7, 2006. In September, 2009, the Court of Appeals issued an opinion reversing the district court and reinstating the lawsuit. Defendants filed a petition for rehearing en banc. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with this matter.

Alaskan Global Warming Lawsuit.

On February 26, 2008, plaintiffs filed suit against Peabody Coal and various oil and power company defendants, including Duke Energy and certain of its subsidiaries. Plaintiffs, the governing bodies of an Inupiat village in Alaska brought the action on their own behalf and on behalf of the village's approximately 400 residents. The lawsuit alleges that defendants' emissions of CO_2 contributed to global warming and constitute a private and public nuisance. Plaintiffs also allege that certain defendants, including Duke Energy, conspired to mislead the public with respect to global warming. Plaintiffs seek unspecified monetary damages, attorney's fees and expenses. On June 30, 2008, the defendants filed a motion to dismiss on jurisdictional grounds, together with a motion to dismiss the conspiracy claims. On October 15, 2009, the District Court granted defendants motion to dismiss and plaintiffs filed a notice of appeal. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with this matter.

Hurricane Katrina Lawsuit.

In April 2006, Duke Energy and Cinergy were named in the third amended complaint of a purported class action lawsuit filed in the U.S. District Court for the Southern District of Mississippi. Plaintiffs claim that Duke Energy and Cinergy, along with numerous other utilities, oil companies, coal companies and chemical companies, are liable for damages relating to losses suffered by victims of Hurricane Katrina. Plaintiffs claim that defendants' greenhouse gas emissions contributed to the frequency and intensity of storms such as Hurricane Katrina. On August 30, 2007, the court dismissed the case and plaintiffs filed a notice of appeal. In October 2009, the Court of Appeals issued an opinion reversing the district court and reinstating the lawsuit. Defendants filed a petition for rehearing en banc. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with this matter.

Price Reporting Cases.

A total of 13 lawsuits have been filed against Duke Energy affiliates and other energy companies. Of the 13 lawsuits, 11 have been consolidated into a single proceeding, including the case originally filed in Wisconsin state court in March 2009. In February 2008, the judge in this proceeding granted a motion to dismiss one of the cases and entered judgment in favor of DETM. Plaintiffs' motion to reconsider was, in large part, denied and on January 9, 2009, the court ruled that plaintiffs lacked standing to pursue their remaining claims and granted certain defendants' motion for summary judgment. In February 2009, the same judge dismissed Duke Energy Carolinas from that case as well as four other of the consolidated cases. In November 2009, the judge granted Defendants' motion for reconsideration of the denial of Defendants' summary judgment motion in two of the remaining 10 cases to which Duke Energy affiliates are a party. In December 2009, plaintiffs in the consolidated cases filed a motion to amend their complaints in the individual cases to add a claim for treble damages under the Sherman Act, including additional factual allegations regarding fraudulent concealment of defendants' allegedly conspiratorial conduct.

One case was filed in Tennessee state court, which dismissed the case based on the filed rate doctrine and federal preemption grounds. That case was appealed to the Tennessee Court of Appeals, which reversed this lower court ruling in October 2008. Defendants' application for permission to appeal to the Tennessee Supreme Court was granted and oral argument occurred in November 2009. On January 13, 2009, another case pending in Missouri state court, was dismissed on the grounds that the plaintiff lacked standing to bring the case and the plaintiff's appeal was heard by the Missouri Court of Appeals in November 2009. In December 2009, the Court of Appeals affirmed the trial court ruling. On February 2, 2010, plaintiffs' motion for rehearing and application for transfer to the Missouri Supreme Court was denied. Plaintiffs have filed a motion to transfer directly for the Missouri Supreme Court. Each of these cases contains similar claims, that the respective plaintiffs, and the classes they claim to represent, were harmed by the defendants' alleged manipulation of the natural gas markets by various means, including providing false information to natural gas trade publications and entering into unlawful arrangements and agreements in violation of the antitrust laws of the respective states. Plaintiffs seek damages in unspecified amounts.

A settlement agreement was executed with the class plaintiffs in five of the 11 consolidated cases in September 2009. The settlement did not have a material adverse effect on Duke Energy's consolidated results of operations, cash flows or financial position. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with the remaining matters.

Western Electricity Litigation.

Plaintiffs, on behalf of themselves and others, in three lawsuits allege that Duke Energy affiliates, among other energy companies, artificially inflated the price of electricity in certain western states. Two of the cases were dismissed and plaintiffs appealed to the U.S. Court of Appeal for the Ninth Circuit. Of those two cases, one was dismissed by agreement in March 2007. In November 2007, the court issued an opinion affirming dismissal of the other case, plaintiffs' motion for reconsideration was denied and plaintiffs did not file a petition for certiorari to the Supreme Court. Plaintiffs in the remaining case seek damages in unspecified amounts. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with these lawsuits, but Duke Energy does not presently believe the outcome of these matters will have a material adverse effect on its consolidated results of operations, cash flows or financial position.

Duke Energy Retirement Cash Balance Plan.

A class action lawsuit was filed in federal court in South Carolina against Duke Energy and the Duke Energy Retirement Cash Balance Plan, alleging violations of Employee Retirement Income Security Act (ERISA) and the Age Discrimination in Employment Act (ADEA). These allegations arise out of the conversion of the Duke Energy Company Employees' Retirement Plan into the Duke Energy Retirement Cash Balance Plan. The case also raises some Plan administration issues, alleging errors in the application of Plan provisions (i.e., the calculation of interest rate credits in 1997 and 1998 and the calculation of lump-sum distributions). The plaintiffs seek to represent present and former participants in the Duke Energy Retirement Cash Balance Plan. This group is estimated to include approximately 36,000 persons. The plaintiffs also seek to divide the putative class into sub-classes based on age. Six causes of action are alleged, ranging from age discrimination, to various alleged ERISA violations, to allegations of breach of fiduciary duty. Plaintiffs seek a broad array of remedies, including a retroactive reformation of the Duke Energy Retirement Cash Balance Plan and a recalculation of participants'/ beneficiaries' benefits under the revised and reformed plan. Duke Energy filed its answer in March 2006. A portion of this contingent liability was assigned to Spectra Energy in connection with the spin-off in January 2007. A hearing on the plaintiffs' motion to amend the complaint to add an additional age discrimination claim, defendant's motion to dismiss and the respective motions for summary judgment was held in December 2007. On June 2, 2008, the court issued its ruling denying plaintiffs' motion to add the additional claim and dismissing a number of plaintiffs' claims, including the claims for ERISA age discrimination. Since that date, plaintiffs have notified Duke Energy that they are withdrawing their ADEA claim. On September 4, 2009, the court issued its order certifying classes for three of the remaining claims but not certifying their claims as to plaintiffs' fiduciary duty claims. At an unsuccessful mediation in September 2008, Plaintiffs quantified their claims as being in excess of $150 million. It is not possible to predict with certainty the damages, if any, that Duke Energy might incur in connection with this matter.

Ohio Antitrust Lawsuit

In January 2008, four plaintiffs, including individual, industrial and non-profit customers, filed a lawsuit against Duke Energy Ohio in federal court in the Southern District of Ohio. Plaintiffs allege that Duke Energy Ohio (then The Cincinnati Gas & Electric Company (CG&E)), conspired to provide inequitable and unfair price advantages for certain large business consumers by entering into non-public option agreements with such consumers in exchange for their withdrawal of challenges to Duke Energy Ohio's (then CG&E's) pending RSP, which was implemented in early 2005. Duke Energy Ohio denies the allegations made in the lawsuit. Following Duke Energy Ohio's filing of a motion to dismiss plaintiffs' claims, plaintiffs amended their complaint on May 30, 2008. Plaintiffs now contend that the contracts at issue were an illegal rebate which violate antitrust and Racketeer Influenced and Corrupt Organizations (RICO) statutes. Defendants have again moved to dismiss the claims. On March 31, 2009, the District Court granted Duke Energy Ohio's motion to dismiss. Plaintiffs have filed a motion to alter or set aside the judgment.

Duke Energy International Paranapanema Lawsuit

On July 16, 2008, Duke Energy International Geracao Paranapanema S.A. (DEIGP) filed a lawsuit in the Brazilian federal court challenging the merits of two resolutions promulgated by the Brazilian electricity regulatory agency (ANEEL) (collectively, the "Resolutions"). The Resolutions purport to impose additional transmission fees (retroactive to July 1, 2004 and effective through June 30, 2009) on generation companies located in the State of São Paulo for utilization of the electric transmission system. The new assessments are based upon a flat-fee charge that fails to take into account the locational usage by each generator. DEIGP has been assessed approximately $45 million, inclusive of interest. DEIGP challenged the assessment in Brazilian federal court. Based on DEIGP's continuing refusal to tender payment of the disputed sums, on April 1, 2009, ANEEL assessed an additional fine against DEIGP in the amount of approximately $7 million. DEIGP filed a request to enjoin payment of the fine and for an expedited decision on the merits or, alternatively, a result that all disputed sums be deposited in the court's registry in lieu of direct payment to the distribution companies.

On June 30, 2009, the court issued a ruling in which it granted DEIGP's request for injunction regarding the second fine and denied DEIGP's request for an expedited decision or payment into the court registry. Under the court's order, DEIGP was required to make payment directly to the distribution companies on the approximate $45 million assessment pending resolution on the merits. As a result of the court's ruling, in the second quarter of 2009, Duke Energy recorded a pre-tax charge of approximately $33 million associated with this matter. The court's ruling also allowed DEIGP to make 31 monthly installment payments on the outstanding obligation. DEIGP filed an appeal and on August 28, 2009, the order requiring installment payments was modified to allow DEIGP to deposit the disputed portion, which was most of the assessed amount, into an escrow account pending resolution on the merits.

Asbestos-related Injuries and Damages Claims.

Duke Energy has experienced numerous claims for indemnification and medical cost reimbursement relating to damages for bodily injuries alleged to have arisen from the exposure to or use of asbestos in connection with construction and maintenance activities conducted by Duke Energy Carolinas on its electric generation plants prior to 1985.

Amounts recognized as asbestos-related reserves related to Duke Energy Carolinas in the Consolidated Balance Sheets totaled approximately $980 million and $1,031 million as of December 31, 2009 and 2008, respectively, and are classified in Other within Deferred Credits and Other Liabilities and Other within Current Liabilities. These reserves are based upon the minimum amount in Duke Energy's best estimate of the range of loss for current and future asbestos claims through 2027. Management believes that it is possible there will be additional claims filed against Duke Energy Carolinas after 2027. In light of the uncertainties inherent in a longer-term forecast, management does not believe that they can reasonably estimate the indemnity and medical costs that might be incurred after 2027 related to such potential claims. Asbestos-related loss estimates incorporate anticipated inflation, if applicable, and are recorded on an undiscounted basis. These reserves are based upon current estimates and are subject to greater uncertainty as the projection period lengthens. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change our estimated liability, as could any substantial adverse or favorable verdict at trial. A federal legislative solution, further state tort reform or structured settlement transactions could also change the estimated liability. Given the uncertainties associated with projecting matters into the future and numerous other factors outside our control, management believes that it is possible Duke Energy Carolinas may incur asbestos liabilities in excess of the recorded reserves.

Duke Energy has a third-party insurance policy to cover certain losses related to Duke Energy Carolinas' asbestos-related injuries and damages above an aggregate self insured retention of $476 million. Duke Energy Carolinas' cumulative payments began to exceed the self insurance retention on its insurance policy during the second quarter of 2008. Future payments up to the policy limit will be reimbursed by Duke Energy's third party insurance carrier. The insurance policy limit for potential future insurance recoveries for indemnification and medical cost claim payments is $1,051 million in excess of the self insured retention. Insurance recoveries of approximately $984 million and $1,032 million related to this policy are classified in the Consolidated Balance Sheets in Other within Investments and Other Assets and Receivables as of December 31, 2009 and 2008, respectively. Duke Energy is not aware of any uncertainties regarding the legal sufficiency of insurance claims. Management believes the insurance recovery asset is probable of recovery as the insurance carrier continues to have a strong financial strength rating.

Duke Energy Indiana and Duke Energy Ohio have also been named as defendants or co-defendants in lawsuits related to asbestos at their electric generating stations. The impact on Duke Energy's consolidated results of operations, cash flows or financial position of these cases to date has not been material. Based on estimates under varying assumptions concerning uncertainties, such as, among others: (i) the number of contractors potentially exposed to asbestos during construction or maintenance of Duke Energy Indiana and Duke Energy Ohio generating plants; (ii) the possible incidence of various illnesses among exposed workers, and (iii) the potential settlement costs without federal or other legislation that addresses asbestos tort actions, Duke Energy estimates that the range of reasonably possible exposure in existing and future suits over the foreseeable future is not material. This estimated range of exposure may change as additional settlements occur and claims are made and more case law is established.

Other Litigation and Legal Proceedings.

Duke Energy and its subsidiaries are involved in other legal, tax and regulatory proceedings arising in the ordinary course of business, some of which involve substantial amounts. Duke Energy believes that the final disposition of these proceedings will not have a material adverse effect on its consolidated results of operations, cash flows or financial position.

Duke Energy has exposure to certain legal matters that are described herein. As of December 31, 2009 and 2008, Duke Energy has recorded reserves, including reserves related to the aforementioned asbestos-related injuries and damages claims, of approximately $1 billion and $1.1 billion, respectively, for these proceedings and exposures. These reserves represent management's best estimate of probable loss as defined in the accounting guidance for contingencies. Duke Energy has insurance coverage for certain of these losses incurred. As of December 31, 2009 and 2008, Duke Energy recognized approximately $984 million and $1,032 million, respectively, of probable insurance recoveries related to these losses.

Duke Energy expenses legal costs related to the defense of loss contingencies as incurred.

Other Commitments and Contingencies

DEGS of Narrows, L.L.C. Investigation.

In October 2006, Duke Energy began an internal investigation into improper data reporting to the EPA regarding air emissions under the NO_x Budget Program at Duke Energy's DEGS of Narrows, L.L.C. power plant facility in Narrows, Virginia. The investigation has revealed evidence of falsification of data by an employee relating to the quality assurance testing of its continuous emissions monitoring system to monitor heat input and NO_x emissions. In December 2006, Duke Energy voluntarily disclosed the potential violations to the EPA and Virginia Department of Environmental Quality (VDEQ), and in January 2007, Duke Energy made a full written disclosure of the investigation's findings to the EPA and the VDEQ. In December 2007, the EPA issued a notice of violation. On March 19, 2009, the EPA advised that it will not pursue criminal charges against Duke Energy, and negotiations can resume resolving the civil violation of the CAA identified in the December 2007 notice of violation. Duke Energy has taken appropriate disciplinary action, including termination, with respect to the employees involved with the false reporting. It is not possible to predict with certainty whether Duke Energy will incur any liability or to estimate the damages, if any, that Duke Energy might incur in connection with this matter. DEGS has reached an agreement in principle to settle the CAA civil violation for an amount that is not material.

General.

As part of its normal business, Duke Energy is a party to various financial guarantees, performance guarantees and other contractual commitments to extend guarantees of credit and other assistance to various subsidiaries, investees and other third parties. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheets. The possibility of Duke Energy having to honor its contingencies is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events. For further information see Note 17.

In addition, Duke Energy enters into various fixed-price, non-cancelable commitments to purchase or sell power (tolling arrangements or power purchase contracts), take-or-pay arrangements, transportation or throughput agreements and other contracts that may or may not be recognized on the Consolidated Balance Sheets. Some of these arrangements may be recognized at market value on the Consolidated Balance Sheets as trading contracts or qualifying hedge positions.

Operating and Capital Lease Commitments

Duke Energy leases assets in several areas of its operations. Consolidated rental expense for operating leases included in income from continuing operations was $129 million in 2009, $164 million in 2008 and $138 million in 2007 which is included in Operation, Maintenance and Other on the Consolidated Statements of Operations. Amortization of assets recorded under capital leases is included in Depreciation and Amortization on the Consolidated Statements of Operations. The following is a summary of future minimum lease payments under operating leases, which at inception had a non-cancelable term of more than one year, and capital leases as of December 31, 2009:

(in millions)	Operating Leases	Capital Leases
2010	$108	$ 26
2011	78	29
2012	64	27
2013	52	25
2014	37	22
Thereafter	197	119
Total future minimum lease payments	$536	$248

17. GUARANTEES AND INDEMNIFICATIONS

Duke Energy and its subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Duke Energy and its subsidiaries enter into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party.

As discussed in Note 1, on January 2, 2007, Duke Energy completed the spin-off of its natural gas businesses to shareholders. Guarantees that were issued by Duke Energy, Cinergy or International Energy, or were assigned to Duke Energy prior to the spin-off remained with Duke Energy subsequent to the spin-off. Guarantees issued by Spectra Energy Capital, LLC (Spectra Capital) or its affiliates prior to the spin-off remained with Spectra Capital subsequent to the spin-off, except for certain guarantees that are in the process of being assigned to Duke Energy. During this assignment period, Duke Energy has indemnified Spectra Capital against any losses incurred under these guarantee obligations. The maximum potential amount of future payments associated with the guarantees issued by Spectra Capital is approximately $250 million.

Duke Energy has issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly-owned entities, as well as guarantees of debt of certain non-consolidated entities and less than wholly-owned consolidated entities. If such entities were to default on payments or performance, Duke Energy would be required under the guarantees to make payments on the obligations of the less than wholly-owned entity. The maximum potential amount of future payments Duke Energy could have been required to make under these guarantees as of December 31, 2009 was approximately $455 million. Of this amount, approximately $195 million relates to guarantees issued on behalf of less than wholly-owned consolidated entities, with the remainder related to guarantees issued on behalf of third parties and unconsolidated affiliates of Duke Energy. Approximately $285 million of the guarantees expire between 2010 and 2021, with the remaining performance guarantees having no contractual expiration.

Included in the maximum potential amount of future payments discussed above is approximately $61 million of maximum potential amounts of future payments associated with guarantees issued to customers or other third parties related to the payment or performance obligations of certain entities that were previously wholly-owned by Duke Energy but which have been sold to third parties, such as DukeSolutions, Inc. (DukeSolutions) and Duke Engineering & Services, Inc. (DE&S). These guarantees are primarily related to payment of lease obligations, debt obligations, and performance guarantees related to provision of goods and services. Duke Energy has received back-to-back indemnification from the buyer of DE&S indemnifying Duke Energy for any amounts paid related to the DE&S guarantees. Duke Energy also received indemnification from the buyer of DukeSolutions for the first $2.5 million paid by Duke Energy related to the DukeSolutions guarantees. Further, Duke Energy granted indemnification to the buyer of DukeSolutions with respect to losses arising under some energy services agreements retained by DukeSolutions after the sale, provided that the buyer agreed to bear 100% of the performance risk and 50% of any other risk up to an aggregate maximum of $2.5 million (less any amounts paid by the buyer under the indemnity discussed above). Additionally, for certain performance guarantees, Duke Energy has recourse to subcontractors involved in providing services to a customer. These guarantees have various terms ranging from 2012 to 2021, with others having no specific term.

Duke Energy has guaranteed certain issuers of surety bonds, obligating itself to make payment upon the failure of a non-wholly-owned entity to honor its obligations to a third party, as well as used bank-issued stand-by letters of credit to secure the performance of non-wholly-owned entities to a third party or customer. Under these arrangements, Duke Energy has payment obligations which are triggered by a draw by the third party or customer due to the failure of the non-wholly-owned entity to perform according to the terms of its underlying contract. Substantially all of these guarantees issued by Duke Energy relate to projects at Crescent that were under development at the time of the joint venture creation in 2006. Crescent filed Chapter 11 petitions in a U.S. Bankruptcy Court in June 2009. During 2009, Duke Energy determined that it was probable that it will be required to perform under certain of these guarantee obligations and recorded a charge of approximately $26 million associated with these obligations, which represented Duke Energy's best estimate of its exposure under these guarantee obligations. At the time the charge was recorded, the face value of the guarantees was approximately $70 million, which has since been reduced to approximately $50 million as of December 31, 2009 as Crescent continues to complete some of its obligations under these guarantees.

Duke Energy has entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time, depending on the nature of the claim. Duke Energy's potential exposure under these indemnification agreements can range from a specified amount, such as the purchase price, to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Duke Energy is unable to estimate the total potential amount of future payments under these indemnification agreements due to several factors, such as the unlimited exposure under certain guarantees.

At December 31, 2009, the amounts recorded on the Consolidated Balance Sheets for the guarantees and indemnifications mentioned above, including performance guarantees associated with projects at Crescent for which it is probable that Duke Energy will be required to perform, is approximately $35 million. This amount is primarily recorded in Other within Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

18. EARNINGS PER SHARE

Basic earnings per share (EPS) is computed by dividing net income attributable to Duke Energy common stockholders, adjusted for distributed and undistributed earnings allocated to participating securities, by the weighted-average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income attributable to Duke Energy common stockholders, as adjusted, by the diluted weighted-average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options, phantom shares and stock-based performance unit awards were exercised or settled.

Effective January 1, 2009, Duke Energy began applying revised accounting guidance for EPS related to participating securities, whereby unvested share-based payment awards that have non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) when dividends are paid to common stockholders, irrespective of whether the award ultimately vests, constitute participation rights and should be included in the computation of basic EPS using the two-class method. All prior period EPS data was retrospectively adjusted to conform to these revised accounting provisions.

The following table illustrates Duke Energy's basic and diluted EPS calculations and reconciles the weighted-average number of common shares outstanding to the diluted weighted-average number of common shares outstanding for the years ended December 31, 2009, 2008, and 2007.

(in millions, except per share amounts)	Income	Average Shares	EPS
2009			
Income from continuing operations attributable to Duke Energy common shareholders, as adjusted for participating securities — basic	$1,061	1,293	$0.82
Effect of dilutive securities:			
Stock options, phantom, performance and unvested stock		1	
Income from continuing operations attributable to Duke Energy common shareholders, as adjusted for participating securities — diluted	$1,061	1,294	$0.82
2008			
Income from continuing operations attributable to Duke Energy common shareholders, as adjusted for participating securities — basic	$1,276	1,265	$1.01
Effect of dilutive securities:			
Stock options, phantom, performance and restricted stock		2	
Income from continuing operations attributable to Duke Energy common shareholders, as adjusted for participating securities — diluted	$1,276	1,267	$1.01
2007			
Income from continuing operations attributable to Duke Energy common shareholders, as adjusted for participating securities — basic	$1,518	1,260	$1.21
Effect of dilutive securities:			
Stock options, phantom, performance and restricted stock		4	
Contingently convertible bond		1	
Income from continuing operations attributable to Duke Energy common shareholders, as adjusted for participating securities — diluted	$1,518	1,265	$1.20

As of December 31, 2009, 2008 and 2007, approximately 20 million, 15 million and 13 million, respectively, of stock options, unvested stock and performance awards were not included in the "effect of dilutive securities" in the above table because either the option exercise prices were greater than the average market price of the common shares during those periods, or performance measures related to the awards had not yet been met.

Beginning in the fourth quarter of 2008, Duke Energy began issuing authorized but previously unissued shares of common stock to fulfill obligations under its Dividend Reinvestment Plan (DRIP) and other internal plans, including 401(k) plans. During the years ended December 31, 2009 and 2008, Duke Energy received proceeds of approximately $494 million and $100 million, respectively, from the sale of common stock associated with these plans.

During 2010, Duke Energy anticipates issuing approximately $400 million of additional authorized but previously unissued shares of common stock under its DRIP and other internal plans.

19. STOCK-BASED COMPENSATION

For employee awards, equity classified stock-based compensation cost is measured at the grant date, based on the fair value of the award, and is recognized as expense or capitalized as a component of property, plant and equipment over the requisite service period.

Duke Energy's 2006 Long-Term Incentive Plan (the 2006 Plan) reserved 60 million shares of common stock for awards to employees and outside directors. The 2006 Plan superseded the 1998 Long-Term Incentive Plan, as amended (the 1998 Plan), and no additional grants will be made from the 1998 Plan. Under the 2006 Plan, the exercise price of each option granted cannot be less than the market price of Duke Energy's common stock on the date of grant and the maximum option term is 10 years. The vesting periods range from immediate to five years. Duke Energy has historically issued new shares upon exercising or vesting of share-based awards. In 2010, Duke Energy may use a combination of new share issuances and open market repurchases for share-based awards which are exercised or become vested; however Duke Energy has not determined with certainty the amount of such new share issuances or open market repurchases.

The 2006 Plan allows for a maximum of 15 million shares of common stock to be issued under various stock-based awards other than options and stock appreciation rights.

Stock-Based Compensation Expense

Pre-tax stock-based compensation expense recorded in the Consolidated Statements of Operations is as follows:

	For the Years Ended December 31,		
(in millions)	2009[a]	2008[a]	2007
Stock Options	$ 2	$ 2	$ 5
Phantom Awards	17	17	20
Performance Awards	20	23	12
Other Stock Awards	1	1	2
Total	$40	$43	$39

(a) Excludes stock-based compensation cost capitalized as a component of property, plant and equipment of approximately $4 million and $3 million for the years ended December 31, 2009 and 2008, respectively.

The tax benefit associated with the stock-based compensation expense for the years ended December 31, 2009, 2008 and 2007 was approximately $16 million, $17 million and $15 million, respectively.

Stock Option Activity

	Options (in thousands)	Weighted-Average Exercise Price	Weighted-Average Remaining Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2008	19,790	$17		
Granted	603	15		
Exercised	(1,822)	13		
Forfeited or expired	(1,265)	17		
Outstanding at December 31, 2009	17,306	$18	3.1	$37
Exercisable at December 31, 2009	16,703	$18	2.8	$36
Options Expected to Vest	603	$15	9.1	$ 2

On December 31, 2008 and 2007, Duke Energy had approximately 19 million and 20 million exercisable options, respectively, with a weighted-average exercise price of approximately $17 at each date. The total intrinsic value of options exercised during the years ended December 31, 2009, 2008 and 2007 was approximately $6 million, $11 million and $26 million, respectively, with a related tax benefit of approximately $2 million, $4 million and $10 million, respectively. Cash received from options exercised during the years ended December 31, 2009, 2008 and 2007 was approximately $24 million, $30 million and $50 million, respectively. There were 603,015 stock options granted during the year ended December 31, 2009, and no stock options granted during the years ended December 31, 2008 or 2007. The options granted in 2009 were expensed immediately, therefore, there is no future compensation cost associated with these options.

These assumptions were used to determine the grant date fair value of the stock options granted during 2009:

Weighted-Average Assumptions for Option Pricing	
Risk-free interest rate[a]	2.0%
Expected dividend yield[b]	5.4%
Expected life[c]	6.0 yrs.
Expected volatility[d]	26.7%

(a) The risk free rate is based upon the U.S. Treasury Constant Maturity rates as of the grant date.
(b) The expected dividend yield is based upon annualized dividends and the 1-year average closing stock price.
(c) The expected term of options is derived from historical data.
(d) Volatility is based upon 50% historical and 50% implied volatility. Historic volatility is based on Duke Energy's historical volatility over the expected life using daily stock prices. Implied volatility is the average for all option contracts with a term greater than six months using the strike price closest to the stock price on the valuation date.

Phantom Stock Awards

Phantom stock awards issued and outstanding under the 2006 Plan generally vest over periods from immediate to three years. Phantom stock awards issued and outstanding under the 1998 Plan generally vest over periods from immediate to five years. Duke Energy awarded 1,095,935 shares (fair value of approximately $16 million, based on the market price of Duke Energy's common stock at the grant date) during the year ended December 31, 2009, 973,515 shares (fair value of approximately $17 million based on the market price of Duke Energy's common stock at the grant date) during the year ended December 31, 2008, and 1,163,180 shares (fair value of approximately $23 million based on the market price of Duke Energy's common stock at the grant date) during the year ended December 31, 2007.

The following table summarizes information about phantom stock awards outstanding at December 31, 2009:

	Shares (in thousands)	Weighted Average Grant Date Fair Value
Number of Phantom Stock Awards:		
Outstanding at December 31, 2008	2,446	$22
Granted	1,096	14
Vested	(1,108)	21
Forfeited	(68)	19
Outstanding at December 31, 2009	2,366	$19
Phantom Stock Awards Expected to Vest	2,286	$19

The total grant date fair value of the shares vested during the years ended December 31, 2009, 2008 and 2007 was approximately $23 million, $20 million and $31 million, respectively. At December 31, 2009, Duke Energy had approximately $8 million of unrecognized compensation cost which is expected to be recognized over a weighted-average period of 1.4 years.

Performance Awards

Stock-based awards issued and outstanding under both the 2006 Plan and the 1998 Plan generally vest over three years if performance targets are met. Vesting for certain stock-based performance awards can occur in three years, at the earliest, if performance is met Certain performance awards granted in 2009, 2008 and 2007 contain market conditions based on the total shareholder return (TSR) of Duke Energy stock relative to a pre-defined peer group (relative TSR). These awards are valued using a path-dependent model that incorporates expected relative TSR into the fair value determination of Duke Energy's performance-based share awards. The model uses three year historical volatilities and correlations for all companies in the pre-defined peer group, including Duke Energy, to simulate Duke Energy's relative TSR as of the end of the performance period. For each simulation, Duke Energy's relative TSR associated with the simulated stock price at the end of the performance period plus expected dividends within the period results in a value per share for the award portfolio. The average of these simulations is the expected portfolio value per share. Actual life to date results of Duke Energy's relative TSR for each grant is incorporated within the model. Other performance awards not containing market conditions were awarded in 2009, 2008 and 2007. The performance goal for these awards is Duke Energy's compounded annual growth rate (CAGR) of annual diluted EPS, adjusted for certain items, over a three year period. These awards are measured at grant date price. Duke Energy awarded 3,426,244 shares (fair value of approximately $44 million) during the year ended December 31, 2009, 2,407,755 shares (fair value of approximately $37 million) during the year ended December 31, 2008, and 1,534,510 shares (fair value of approximately $23 million) during the year ended December 31, 2007.

The following table summarizes information about stock-based performance awards outstanding at December 31, 2009:

	Shares (in thousands)	Weighted Average Grant Date Fair Value
Number of Stock-based Performance Awards:		
Outstanding at December 31, 2008	4,980	$16
Granted	3,426	13
Vested	(1,069)	19
Forfeited	(468)	16
Outstanding at December 31, 2009	6,869	$14
Stock-based Performance Awards Expected to Vest	4,177	$14

The total grant date fair value of the shares vested during the years ended December 31, 2009, 2008 and 2007 was approximately $20 million, $20 million and $34 million, respectively. At December 31, 2009, Duke Energy had approximately $28 million of unrecognized compensation cost which is expected to be recognized over a weighted-average period of 1.2 years.

Other Stock Awards

Other stock awards issued and outstanding under the 1998 Plan vest over periods from three to five years. There were no other stock awards issued during the years ended December 31, 2009, 2008 or 2007.

The following table summarizes information about other stock awards outstanding at December 31, 2009:

	Shares (in thousands)	Weighted Average Grant Date Fair Value
Number of Other Stock Awards:		
Outstanding at December 31, 2008	219	$29
Vested	(48)	29
Forfeited	(3)	28
Outstanding at December 31, 2009	168	$28
Other Stock Awards Expected to Vest	162	$28

The total fair value of the shares vested during the years ended December 31, 2009, 2008 and 2007 was approximately $1 million, $2 million, and $2 million, respectively. At December 31, 2009, Duke Energy had approximately $1 million of unrecognized compensation cost which is expected to be recognized over a weighted-average period of 1.0 year.

20. EMPLOYEE BENEFIT PLANS

Defined Benefit Retirement Plans

Duke Energy and its subsidiaries (including legacy Cinergy businesses) maintain qualified, non-contributory defined benefit retirement plans. The plans cover most U.S. employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits that are based upon a percentage (which varies with age and years of service) of current eligible earnings and current interest credits. Certain legacy Cinergy U.S. employees are covered under plans that use a final average earnings formula. Under a final average earnings formula, a plan participant accumulates a retirement benefit equal to a percentage of their highest 3-year average earnings, plus a percentage of their highest 3-year average earnings in excess of covered compensation per year of participation (maximum of 35 years), plus a percentage of their highest 3-year average earnings times years of participation in excess of 35 years. Duke Energy also maintains non-qualified, non-contributory defined benefit retirement plans which cover certain executives.

Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefit payments to be paid to plan participants. During 2009, Duke Energy made contributions to its U.S. qualified pension plans of approximately $800 million. There were no contributions to the U.S. qualified pension plans during the year ended December 31, 2008. Duke Energy made a contribution of approximately $350 million to the legacy Cinergy qualified pension plans during the year ended December 31, 2007.

Actuarial gains and losses are amortized over the average remaining service period of the active employees. The average remaining service period of active employees covered by the qualified retirement plans is 11 years. The average remaining service period of active employees covered by the non-qualified retirement plans is nine years. Duke Energy determines the market-related value of plan assets using a calculated value that recognizes changes in fair value of the plan assets in a particular year on a straight line basis over the next five years.

Net periodic benefit costs disclosed in the tables below for the qualified, non-qualified and other post-retirement benefit plans represent the cost of the respective benefit plan for the periods presented. However, portions of the net periodic benefit costs disclosed in the tables below have been capitalized as a component of property, plant and equipment.

As required by the applicable accounting rules, Duke Energy uses a December 31 measurement date for its plan assets.

Qualified Pension Plans

Components of Net Periodic Pension Costs: Qualified Pension Plans

	For the Years Ended December 31,		
(in millions)	2009[a]	2008[a]	2007[a]
Service cost	$ 85	$ 92	$ 96
Interest cost on projected benefit obligation	257	254	246
Expected return on plan assets	(362)	(340)	(319)
Amortization of prior service cost	7	7	5
Amortization of loss	2	13	32
Other	17	20	20
Net periodic pension costs	$ 6	$ 46	$ 80

(a) These amounts exclude approximately $10 million, $13 million and $17 million for the years ended December 31, 2009, 2008 and 2007, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

Qualified Pension Plans — Other Changes in Plan Assets and Projected Benefit Obligations

Recognized in Accumulated Other Comprehensive Income and Regulatory Assets[a]

(in millions)	For the year ended December 31, 2009
Regulatory assets, net decrease	$(22)
Accumulated other comprehensive (income)/loss	
Deferred income tax asset	9
Actuarial gain arising during 2009	(8)
Prior service credit arising during 2009	(7)
Amortization of prior year actuarial losses	(1)
Amortization of prior year prior service cost	(4)
Net amount recognized in accumulated other comprehensive (income)/loss	$(11)

(a) Excludes actuarial gains recognized in other accumulated comprehensive income of approximately $9 million, net of tax, associated with a Brazilian retirement plan.

Reconciliation of Funded Status to Net Amount Recognized: Qualified Pension Plans

	As of and for the Years Ended December 31,	
(in millions)	2009	2008
Change in Projected Benefit Obligation		
Obligation at prior measurement date	$4,161	$4,301
Service cost	85	92
Interest cost	257	254
Actuarial losses (gains)	415	(182)
Plan amendments	(9)	—
Obligation assumed from plan merger	7	—
Benefits paid	(221)	(304)
Obligation at measurement date	$4,695	$4,161

The accumulated benefit obligation was approximately $4,409 million and $3,823 million at December 31, 2009 and 2008, respectively.

	As of and for the Years Ended December 31,	
(in millions)	2009	2008
Change in Fair Value of Plan Assets		
Plan assets at prior measurement date	$2,853	$ 4,321
Actual return on plan assets	787	(1,164)
Benefits paid	(221)	(304)
Assets received from plan merger	5	—
Employer contributions	800	—
Plan assets at measurement date	$4,224	$ 2,853

Qualified Pension Plans — Amounts Recognized in the Consolidated Balance Sheets Consist of:

(in millions)	As of and for the Years Ended December 31, 2009	2008
Accrued pension liability	$(471)	$(1,308)

The following table provides the amounts related to Duke Energy's qualified pension plans that are reflected in Other within *Regulatory Assets and Deferred Debits and AOCI on the Consolidated* Balance Sheets at December 31, 2009 and 2008:

(in millions)	As of December 31, 2009	2008
Regulatory assets	$ 909	$ 931
Accumulated other comprehensive (income) loss		
Deferred income tax asset	(206)	(215)
Prior service cost	27	38
Net actuarial loss	528	537
Net amount recognized in accumulated other comprehensive (income) loss[a]	$ 349	$ 360

(a) Excludes accumulated other comprehensive income of approximately $21 million and $12 million, respectively, net of tax, associated with a Brazilian retirement plan.

Of the amounts above, approximately $48 million of unrecognized net actuarial loss and approximately $5 million of unrecognized prior service cost will be recognized in net periodic pension costs in 2010.

Additional Information:

Qualified Pension Plans — Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

(in millions)	As of December 31, 2009	2008
Projected benefit obligation	$4,695	$4,161
Accumulated benefit obligation	4,409	3,823
Fair value of plan assets	4,224	2,853

Qualified Pension Plans — Assumptions Used for Pension Benefits Accounting

(percentages)	2009	2008	2007
Benefit Obligations			
Discount rate	5.50	6.50	6.00
Salary increase (graded by age)	4.50	4.50	5.00

	2009	2008	2007
Determined Expense			
Discount rate	6.50	6.00	5.75
Salary increase	4.50	5.00	5.00
Expected long-term rate of return on plan assets	8.50	8.50	8.50

The discount rate used to determine the current year pension obligation and following year's pension expense is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on a bond universe of AA and AAA-rated long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

Non-Qualified Pension Plans

Components of Net Periodic Pension Costs: Non-Qualified Pension Plans

(in millions)	For the Years Ended December 31, 2009	2008	2007
Service cost	$ 2	$ 2	$ 2
Interest cost on projected benefit obligation	10	10	10
Amortization of prior service cost	2	3	2
Amortization of actuarial loss	—	1	—
Settlement credit	(1)	—	—
Net periodic pension costs	$13	$16	$14

Non-qualified Pension Plans — Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Accumulated Other Comprehensive Income

(in millions)	For the year ended December 31, 2009
Accumulated other comprehensive (income)/loss	
Deferred income tax asset	$ (4)
Actuarial losses arising during 2009	15
Amortization of prior year actuarial losses	(1)
Amortization of prior year prior service cost	(3)
Net amount recognized in accumulated other comprehensive (income)/loss	$ 7

Reconciliation of Funded Status to Net Amount Recognized: Non-Qualified Pension Plans

(in millions)	As of and for the Years Ended December 31, 2009	2008
Change in Projected Benefit Obligation		
Obligation at prior measurement date	$166	$172
Service cost	2	2
Interest cost	10	10
Actuarial losses (gains)	14	(4)
Benefits paid	(19)	(14)
Obligation at measurement date	$173	$166

(in millions)	As of and for the Years Ended December 31, 2009	2008
Change in Fair Value of Plan Assets		
Benefits paid	$(19)	$(14)
Employer contributions	19	14
Plan assets at measurement date	$ —	$ —

The accumulated benefit obligation was approximately $159 million and $154 million at December 31, 2009 and 2008, respectively.

Non-Qualified Pension Plans — Amounts Recognized in the Consolidated Balance Sheets Consist of:

(in millions)	As of December 31, 2009	2008
Accrued pension liability[a]	$(173)	$(166)

(a) Includes approximately $15 million and $20 million recognized in Other within Current Liabilities on the Consolidated Balance Sheets as of December 31, 2009 and 2008, respectively.

The following table provides the amounts related to Duke Energy's non-qualified pension plans that are reflected in AOCI on the Consolidated Balance Sheets at December 31, 2009 and 2008:

(in millions)	As of December 31, 2009	2008
Accumulated other comprehensive (income) loss		
Deferred income tax asset	$ (7)	$ (3)
Prior service cost	12	15
Net actuarial loss (gain)	8	(6)
Net amount recognized in accumulated other comprehensive (income) loss	$13	$ 6

Of the amounts above, approximately $2 million of unrecognized prior service cost and approximately $1 million of unrecognized net actuarial loss will be recognized in net periodic pension costs in 2010

Additional Information:

Non-Qualified Pension Plans — Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

(in millions)	As of December 31, 2009	2008
Projected benefit obligation	$173	$166
Accumulated benefit obligation	159	154
Fair value of plan assets	—	—

Non-Qualified Pension Plans — Assumptions Used for Pension Benefits Accounting

(percentages)	2009	2008	2007
Benefit Obligations			
Discount rate	5.50	6.50	6.00
Salary increase	4.50	4.50	5.00
	2009	2008	2007
Determined Expense			
Discount rate	6.50	6.00	5.75
Salary increase	4.50	5.00	5.00

The discount rate used to determine the current year pension obligation and following year's pension expense is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on a bond universe of AA and AAA-rated long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

Other Post-Retirement Benefit Plans

Duke Energy and most of its subsidiaries provide some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans.

Duke Energy did not make any contributions to its other post-retirement benefit plans in 2009 or 2008. During the year ended December 31, 2007, Duke Energy contributed approximately $62 million to its other post-retirement benefit plans.

These benefit costs are accrued over an employee's active service period to the date of full benefits eligibility. The net unrecognized transition obligation is amortized over approximately 20 years. Actuarial gains and losses are amortized over the average remaining service period of the active employees. The average remaining service period of the active employees covered by the plan is 12 years.

Components of Net Periodic Other Post-Retirement Benefit Costs

	For the Years Ended December 31,		
(in millions)	2009[a]	2008[a]	2007[a]
Service cost	$ 7	$ 7	$11
Interest cost on accumulated post-retirement benefit obligation	46	44	57
Expected return on plan assets	(16)	(16)	(9)
Amortization of prior service (credit) cost	(8)	(8)	2
Amortization of net transition liability	10	11	10
Amortization of (gain) loss	(5)	(2)	6
Special termination benefit cost	—	—	8
Prior period accounting true-up adjustment[b]	—	(55)	—
Net periodic other post-retirement benefit costs	$ 34	$(19)	$85

(a) These amounts exclude approximately $9 million, $9 million and $10 million for the years ended December 31, 2009, 2008 and 2007, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.
(b) Represents the correction of errors, primarily in periods prior to 2008, related to the accounting for Duke Energy's other post-retirement benefit plans that would have reduced amounts recorded as other post-retirement benefit expense during those historical periods. Of this amount, approximately $15 million was capitalized as a component of property, plant and equipment.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 introduced a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans. Accounting guidance issued and adopted by Duke Energy in 2004 prescribes the appropriate accounting for the federal subsidy. The after-tax effect on net periodic post-retirement benefit cost was a decrease of $3 million in 2009, $3 million in 2008 and $3 million in 2007. Duke Energy recognized an approximate $5 million and $8 million subsidy receivable as of December 31, 2009 and 2008, respectively, which is included in Receivables on the Consolidated Balance Sheets.

Other Post-Retirement Benefit Plans — Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Accumulated Other Comprehensive Income, Regulatory Assets and Regulatory Liabilities

(in millions)	For the year ended December 31, 2009
Regulatory assets, net increase	$66
Regulatory liabilities, net increase	91
Accumulated other comprehensive (income)/loss	
Deferred income tax liability	(2)
Actuarial loss arising during 2009	3
Amortization of prior year prior service credit	2
Amortization of prior year actuarial gains	1
Amortization of prior year net transition liability	(2)
Net amount recognized in accumulated other comprehensive (income)/loss	$ 2

Reconciliation of Funded Status to Accrued Other Post-Retirement Benefit Costs

	As of and for the Years Ended December 31,	
(in millions)	2009	2008
Change in Benefit Obligation		
Accumulated post-retirement benefit obligation at prior measurement date	$738	$ 905
Service cost	7	7
Interest cost	46	44
Plan participants' contributions	21	22
Actuarial gain	(11)	(170)
Plan amendments	—	(10)
Plan transfer	2	—
Benefits paid	(80)	(65)
Accrued retiree drug subsidy	5	5
Accumulated post-retirement benefit obligation at measurement date	$728	$ 738

	As of and for the Years Ended December 31,	
(in millions)	2009	2008
Change in Fair Value of Plan Assets		
Plan assets at prior measurement date	$169	$224
Actual return on plan assets	28	(49)
Benefits paid	(80)	(65)
Employer contributions	31	37
Plan participants' contributions	21	22
Plan assets at measurement date	$169	$169

Duke Energy uses a December 31 measurement date for its plan assets.

Other Post-Retirement Benefit Plans- Amounts Recognized in the Consolidated Balance Sheets Consist of:

	As of December 31,	
(in millions)	2009	2008
Accrued other post-retirement liability[a]	$(559)	$(569)

(a) Includes approximately $3 million and $2 million recognized in Other within Current Liabilities on the Consolidated Balance Sheets as of December 31, 2009 and 2008, respectively.

The following table provides the amounts related to Duke Energy's other post-retirement benefit plans that are reflected in Other within Regulatory Assets and Deferred Debits, Other within Deferred Credits and Other Liabilities and AOCI on the Consolidated Balance Sheets at December 31, 2009 and 2008:

	As of December 31,	
(in millions)	2009	2008
Regulatory assets	$ 73	$ 7
Regulatory liabilities	91	—
Accumulated other comprehensive (income)/loss:		
Deferred income tax liability	2	4
Net transition obligation	4	6
Prior service credit	(14)	(16)
Net actuarial loss (gain)	3	(1)
Net amount recognized in accumulated other comprehensive (income)/loss	$ (5)	$ (7)

Of the amounts above, approximately $10 million of unrecognized net transition obligation, approximately $4 million of unrecognized gains and approximately $8 million of unrecognized prior service credit (which will reduce pension expense) will be recognized in net periodic pension costs in 2010.

Assumptions Used for Other Post-Retirement Benefits Accounting

(percentages)	2009	2008	2007
Determined Benefit Obligations			
Discount rate	5.50	6.50	6.00
	2009	2008	2007
Determined Expense			
Discount rate	6.50	6.00	5.75
Expected long-term rate of return on plan assets	5.53-8.50	5.53-8.50	5.53-8.50
Assumed tax rate[(a)]	35.0	35.0	35.0

(a) Applicable to the health care portion of funded post-retirement benefits.

The discount rate used to determine the current year other post-retirement benefits obligation and following year's other post-retirement benefits expense is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on a bond universe of AA and AAA-rated long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

Assumed Health Care Cost Trend Rates[(a)]

	Medicare Trend Rate		Prescription Drug Trend Rate	
	2009	2008	2009	2008
Health care cost trend rate assumed for next year	8.50%	8.50%	11.00%	11.00%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2019	2013	2024	2022

(a) Health care cost trend rates include prescription drug trend rate due to the effect of the Modernization Act.

***Sensitivity to Changes in Assumed Health Care Cost Trend Rates* (in millions)**

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total service and interest costs	$ 3	$ (2)
Effect on post-retirement benefit obligation	38	(34)

Expected Benefit Payments

The following table presents Duke Energy's expected benefit payments to participants in its qualified, non-qualified and other post-retirement benefit plans over the next 10 years, which are primarily paid out of the assets of the various trusts. These benefit payments reflect expected future service, as appropriate.

(in millions)	Qualified Plans	Non-Qualified Plans	Other Post-Retirement Plans[(a)]	Total
Years Ended December 31,				
2010	$ 405	$16	$ 56	$ 477
2011	423	16	60	499
2012	433	15	61	509
2013	431	14	62	507
2014	429	22	63	514
2015 – 2019	2,020	60	323	2,403

(a) Duke Energy expects to receive future subsidies under Medicare Part D of approximately $4 million in each of the years 2010-2013, approximately $5 million in 2014, and a total of approximately $24 million during the years 2015-2019.

Plan Assets

Master Retirement Trust.

Assets for both the qualified pension and other post-retirement benefits are maintained in a Master Retirement Trust (Master Trust). Approximately 97% of Master Trust assets were allocated to qualified pension plans and approximately 3% were allocated to other post-retirement plans, as of December 31, 2009 and 2008, respectively. The investment objective of the Master Trust is to achieve reasonable returns, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The long-term rate of return of 8.5% as of December 31, 2009 for the Master Trust was developed using a weighted-average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers. The weighted-average returns expected by asset classes were 3.2% for U.S. equities, 2.0% for Non-U.S. equities, 1.0% for Global equities, 2.0% for fixed income securities, and 0.3% for real estate. The asset allocation targets were set after considering the investment objective and the risk profile. U.S. equities are held for their high expected return. Non-U.S. equities, debt securities, and real estate are held for diversification. Investments within asset classes are to be diversified to achieve broad market participation and reduce the impact of individual managers or investments. Duke Energy regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate. The following table presents target and actual asset allocations for the Master Trust at December 31, 2009 and 2008:

	Target Allocation	Percentage at December 31, 2009	Percentage at December 31, 2008
Asset Category			
U.S. equity securities	34%	33%	31%
Non-U.S. equity securities	20	20	17
Global equity securities	10	10	10
Debt securities	32	28	36
Real estate and cash	4	9	6
Total	100%	100%	100%

VEBA I/II.

Duke Energy also invests other post-retirement assets in the Duke Energy Corporation Employee Benefits Trust (VEBA I) and the Duke Energy Corporation Post-Retirement Medical Benefits Trust (VEBA II). The investment objective of the VEBAs is to achieve sufficient returns, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants. The VEBAs are passively managed. The following tables present target and actual asset allocations for the VEBAs at December 31, 2009 and 2008:

VEBA I

	Target Allocation	Percentage at December 31, 2009	Percentage at December 31, 2008
Asset Category			
U.S. equity securities	30%	23%	20%
Debt securities	45	37	40
Cash	25	40	40
Total	100%	100%	100%

VEBA II

	Target Allocation	Percentage at December 31, 2009	Percentage at December 31, 2008
Asset Category			
U.S. equity securities	50%	—%	38%
Debt securities	50	92	52
Cash	—	8	10
Total	100%	100%	100%

Fair Value Measurements.

On December 31, 2009, Duke Energy adopted the new fair value disclosure requirements for pension and other post-retirement benefit plan assets. The accounting guidance for fair value defines fair value, establishes a framework for measuring fair value in GAAP in the U.S. and expands disclosure requirements about fair value measurements. Under the accounting guidance for fair value, fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received by Duke Energy to sell an asset or paid to transfer a liability versus an entry price, which would be the price paid to acquire an asset or received to assume a liability. Although the accounting guidance for fair value does not require additional fair value measurements, it applies to other accounting pronouncements that require or permit fair value measurements.

Duke Energy classifies recurring and non-recurring fair value measurements based on the following fair value hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 — unadjusted quoted prices in active markets for identical assets or liabilities that Duke Energy has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occurs with sufficient frequency and volume to provide ongoing pricing information. Duke Energy does not adjust quoted market prices on Level 1 for any blockage factor.

Notes to Consolidated Financial Statements – (Continued)

Level 2 — a fair value measurement utilizing inputs other than a quoted market price that are observable, either directly or indirectly, for the asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 — any fair value measurements which include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A level 3 measurement may be based primarily on level 2 inputs.

The following table provides the fair value measurement amounts for Master Trust qualified pension and other post-retirement assets at December 31, 2009.

(in millions)	Total Fair Value Amounts at December 31, 2009[a]	Level 1	Level 2	Level 3
Description				
Equity securities	$2,587	$1,733	$ 831	$ 23
Corporate bonds	1,008	—	989	19
Short-term investment funds	341	39	302	—
Partnership interests	109	—	—	109
Real estate investment trust	64	—	—	64
U.S. Government securities	57	—	57	—
Other investments	43	38	4	1
Guaranteed investment contracts	38	—	—	38
Government bonds — Foreign	33	—	32	1
Asset backed securities	19	—	18	1
Government and commercial mortgage backed securities	14	—	14	—
Total Assets	$4,313	$1,810	$2,247	$256

(a) Excludes approximately $22 million in net receivables and payables associated with security purchases and sales.

The following table provides the fair value measurement amounts for VEBA I/II other post-retirement assets at December 31, 2009.

(in millions)	Total Fair Value Amounts at December 31, 2009	Level 1	Level 2	Level 3
Description				
Cash and cash equivalents	$27	$—	$27	$—
Equity securities	12	11	1	—
Debt securities	19	—	19	—
Total Assets	$58	$11	$47	$—

The following table provides a reconciliation of beginning and ending balances of Master Trust assets measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3):

Year Ended December 31, 2009

Balance at January 1, 2009	$318
Purchases, sales, issuances and settlements (net)	(23)
Total losses, (realized and unrealized) and other	(39)
Balance at December 31, 2009	$256

Valuation methods of the primary fair value measurements disclosed above are as follows:

Investments in equity securities:

Investments in equity securities are typically valued at the closing price in the principal active market as of the last business day of the quarter. Principal active markets for equity prices include published exchanges such as NASDAQ and NYSE. Foreign equity prices are translated from their trading currency using the currency exchange rate in effect at the close of the principal active market. Duke Energy has not adjusted prices to reflect for after-hours market activity. Most equity security valuations are level 1 measures. Investments in equity securities with unpublished prices are valued as level 2 if they are redeemable at the measurement date. Investments in equity securities with redemption restrictions are valued as level 3.

Investments in corporate bonds and U.S. government securities:

Most debt investments are valued based on a calculation using interest rate curves and credit spreads applied to the terms of the debt instrument (maturity and coupon interest rate) and consider the counterparty credit rating. Most debt valuations are Level 2 measures. If the market for a particular fixed income security is relatively inactive or illiquid, the measurement is a Level 3 measurement.

Investments in short-term investment funds:

Valued at the net asset value of units held at year end. Investments in short-term investment funds with published prices are valued as level 1. Investments in short-term investment funds with unpublished prices are valued as level 2.

Investments in real estate investment trust:

Valued based upon property appraisal reports prepared by independent real estate appraisers. The Chief Real Estate Appraiser of the asset manager is responsible for assuring that the valuation process provides independent and reasonable property market value estimates. An external appraisal management firm not affiliated with the asset manager has been appointed to assist the Chief Real Estate Appraiser in maintaining and monitoring the independence and the accuracy of the appraisal process.

Employee Savings Plans

Duke Energy sponsors employee savings plans that cover substantially all U.S. employees. Most employees participate in a matching contribution formula where Duke Energy provides a matching contribution generally equal to 100% of before-tax employee contributions, of up to 6% of eligible pay per pay period. Duke Energy made pre-tax employer matching contributions of approximately $80 million in 2009, $78 million in 2008 and $68 million in 2007. Dividends on Duke Energy shares held by the savings plans are charged to retained earnings when declared and shares held in the plans are considered outstanding in the calculation of basic and diluted earnings per share.

21. VARIABLE INTEREST ENTITIES

Power Sale Special Purpose Entities (SPEs).

Duke Energy is the primary beneficiary of and consolidates two thinly-capitalized SPEs that have been created to finance and execute individual power sale agreements with Central Maine Power Company (CMP) for approximately 45 MW of capacity, which expired in 2009, and 35 MW of capacity, ending in 2016. In addition, these SPEs have individual power purchase agreements (PPA) with Duke Energy Commercial Enterprises, Inc. (DECE), formerly Cinergy Capital & Trading, Inc., a wholly-owned subsidiary of Duke Energy, to supply the power. DECE also provides various services, including certain credit support facilities. The following summarizes the structure of each entity:

CinCap IV.

CinCap IV was created in July 1998 to facilitate the buyout of a power sales agreement that Stratton Energy Associates (Stratton) held with CMP. Approximately $159 million was paid to Stratton to buyout that contract. This capital was raised through two debt tranches (approximately 96.7% of CinCap IV capitalization) and equity (approximately 3.3% of CinCap IV capitalization). The equity was provided by 1998 CinPower Trust, which is in turned owned 90% by Barclays (3% holder) and 10% by DECE. The capitalization (along with certain miscellaneous fees) of CinCap IV is to be repaid through a monthly reservation payment from CMP. Contemporaneous with the buyout of the Stratton PPA, CinCap IV executed a power sales agreement with CMP (Replacement PPA) to deliver 45 MW of capacity and energy to CMP. CinCap IV also executed a power purchase agreement with DECE (Supply PPA) that contains virtually identical terms, except for the aforementioned reservation payment and a $3 less per MWh energy charge. Cinergy guaranteed the performance of DECE under this PPA (with market-based liquidated damages), but did not guarantee the payment by CinCap IV on its debt obligations. This agreement expired in 2009. As of December, 31, 2009, the balance on the Consolidated Balance Sheets related to CinCap IV was an insignificant amount.

CinCap V.

CinCap V was created in February 1999 to facilitate the buyout of a power sales agreement that Alternative Energy (AEI) held with CMP. Approximately $96 million was paid to AEI to buyout that contract. This capital was raised through two debt tranches (approximately 96.7% of CinCap V capitalization) and equity (approximately 3.3% of CinCap IV capitalization). The equity was provided by two parties: (a) 90% by Franklin Life Insurance Company and (b) 10% by DECE. The capitalization (along with certain miscellaneous fees) of CinCap V is being repaid through a monthly reservation payment from CMP. Contemporaneous with the buyout of the AEI PPA, CinCap V executed a power sales agreement with CMP (Replacement PPA) to deliver 35 MW (only 25 in certain months) of capacity and energy to CMP through December 2016. CinCap V also executed a power purchase agreement with DECE (Supply PPA) that contains virtually identical terms, except for the aforementioned reservation payment and a $0.50 less per MWh energy charge. Cinergy guarantees the performance of DECE under this PPA (with market-based liquidated damages), but does not guarantee the payment by CinCap IV on its debt obligations.

These two SPEs meet the accounting definition of a VIE because the equity investment at risk in these SPEs is insufficient to permit the financing of their activities without additional subordinated financial support (i.e., debt financing). As a result of a quantitative analysis of the contractual, ownership, and other financial interests in the SPEs (i.e., variable interests), Duke Energy has been deemed the primary beneficiary of these entities as it absorbs a majority of the expected losses of these SPEs. Accordingly, Duke Energy consolidates these SPEs and, as such, the transactions between DECE and the two SPEs are eliminated in consolidation.

As a result of the consolidation of these two SPEs, approximately $94 million and $117 million of notes receivable is included on the Consolidated Balance Sheets at December 31, 2009 and 2008, respectively. Of these amounts, $8 million and $24 million are included in Receivables on the Consolidated Balance Sheets and $86 million and $93 million are included in Notes Receivable on the Consolidated Balance Sheets at December 31, 2009 and 2008, respectively. Approximately $89 million and $108 million of non-recourse debt is included on the Consolidated Balance Sheets, of which $8 million and $19 million is included in Current Maturities of Long-Term Debt on the Consolidated Balance Sheets and $81 million and $89 million is included in Long-Term Debt on the Consolidated Balance Sheets at December 31, 2009 and 2008, respectively. In addition, miscellaneous other assets and liabilities are included on Duke Energy's Consolidated Balance Sheets at December 31, 2009 and 2008. The debt was incurred by the SPEs to finance the buyout of the existing power contracts that CMP held with the former suppliers. The notes receivable is comprised of two separate notes with one counterparty, whose credit rating is BBB+. The cash flows from the notes receivable are designed to repay the debt. The first note receivable matured in August 2009, and had a balance of $17 million at December 31, 2008, at an effective interest rate of 7.81%. The second note receivable, with a balance of $94 million and $100 million at December 31, 2009 and 2008, respectively, bears an effective interest rate of 9.23% and matures in December 2016.

The following table reflects the maturities of the Notes Receivable as of December 31, 2009:

Notes Receivable Maturities

(in millions)	
2010	$ 8
2011	10
2012	11
2013	13
2014	15
Thereafter	37
Total	$94

Accounts Receivable Securitization.

Cinergy Receivables Company.

During 2002, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky entered into an agreement to sell certain of their accounts receivable and related collections through Cinergy Receivables, a bankruptcy remote, QSPE. Cinergy Receivables is a wholly-owned limited liability company of Cinergy and was formed in 2002 through a $5 million equity contribution by Cinergy to purchase certain accounts receivable of Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky. The purpose of the formation of Cinergy Receivables was to improve liquidity at the lowest possible financing cost. As a result of the securitization, Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky sell, on a revolving basis, nearly all of their retail accounts receivable and a portion of their wholesale accounts receivable and related collections. The securitization transaction was structured to meet the criteria for sale accounting treatment under the accounting guidance for transfers and servicing of financial assets and, accordingly through December 31, 2009, Duke Energy did not consolidate Cinergy Receivables and the transfers of receivables were accounted for as sales. Accordingly, through December 31, 2009, Duke Energy accounted for Cinergy Receivables under the equity method of accounting and all of the earnings or losses of Cinergy Receivables are therefore reflected in Duke Energy's consolidated earnings. Effective with the adoption of new accounting rules related to consolidations and transfers and servicing of financial assets on January 1, 2010, Duke Energy began consolidating Cinergy Receivables. The consolidation of Cinergy Receivables resulted in increases in net Receivables and Short-term Debt on the Consolidated Balance Sheets. While the impact on the balance sheet in future periods will be based on the amount of receivables sold to Cinergy Receivables, at December 31, 2009, approximately $600 million of receivables were sold to Cinergy Receivables, of which approximately $340 million was reflected in Receivables on the Consolidated Balance Sheets as they represented a retained interest in the receivables sold. Effective with the consolidation of Cinergy Receivables, Duke Energy no longer reflects a retained interest in the receivables sold since all receivable sold to Cinergy Receivables, net of loss on sale, do not qualify for sale accounting treatment under the accounting rules for transfers and servicing of financial assets and, thus, are reflected on the Consolidated Balance Sheets. Additionally, effective January 1, 2010, Duke Energy's Consolidated Balance Sheets reflect Short-term Debt approximating the value of the sold receivables. The consolidation of Cinergy Receivables also impacts Duke Energy's Statements of Operations as the activity of the Cinergy Receivables facility is now being reflected on a gross basis within Operating Expenses and Interest Expense versus on a net basis in Equity in Earnings (Losses) of Unconsolidated Affiliates.

The proceeds obtained from the sales of receivables are largely cash but do include a subordinated note from Cinergy Receivables for a portion of the purchase price (typically approximates 25% of the total proceeds). The note, which amounts to approximately $340 million and $292 million at December 31, 2009 and 2008, respectively, is subordinate to senior loans that Cinergy Receivables obtains from commercial paper conduits controlled by unrelated financial institutions. Cinergy Receivables provides credit enhancement related to senior loans in the form of over-collateralization of the purchased receivables. However, the over-collateralization is calculated monthly and does not extend to the entire pool of receivables held by Cinergy Receivables at any point in time. As such, these senior loans do not have recourse to all assets of Cinergy Receivables. These loans provide the cash portion of the proceeds paid to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky.

This subordinated note is a retained interest (right to receive a specified portion of cash flows from the sold assets) under the accounting guidance for transfers and servicing of financial assets and is classified within Receivables in the accompanying Consolidated Balance Sheets at December 31, 2009 and 2008. In addition, Duke Energy's investment in Cinergy Receivables constitutes a purchased beneficial interest (purchased right to receive specified cash flows, in this case residual cash flows), which is subordinate to the retained interests held by Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky. Effective January 1, 2010, with the consolidation of Cinergy Receivables, this subordinated retained interest as of December 31, 2009 will be replaced on the Consolidated Balance Sheets with the previously transferred accounts receivable balances.

In 2008, Cinergy Receivables and Duke Energy Ohio, Duke Energy Kentucky and Duke Energy Indiana amended the governing purchase and sale agreement to allow Cinergy Receivables to convey its bankrupt receivables to the applicable originator for consideration equal to the fair market value of such receivables as of the disposition date. The amount of bankrupt receivables sold is limited to 1% of aggregate sales of the originator during the most recently completed 12 month period. Cinergy Receivables and Duke Energy Ohio, Duke Energy Kentucky and Duke Energy Indiana completed a sale under this amendment in 2008.

Per the governing purchase and sale agreement, Cinergy Receivables is required to maintain a minimum net worth of $3 million. In December 2008, Cinergy Receivables recorded a $15 million increase in its provision for uncollectible accounts which reduced its net worth below the $3 million threshold. During the first quarter of 2009, Cinergy infused approximately $3.5 million of equity into Cinergy Receivables to remedy the net worth deficiency. In June 2009, Cinergy Receivables recorded a $5 million increase in its provision for uncollectible accounts which reduced its net worth below the $3 million threshold. During July 2009, Cinergy infused $7 million of equity into Cinergy Receivables to remedy the net worth deficiency. In December 2009, Cinergy Receivables recorded a $3 million increase in its provision for uncollectible accounts which reduced its net worth below the $3 million threshold. During February 2010, Cinergy infused approximately $6 million of equity into Cinergy Receivables to remedy the net worth deficiency. The greater amount of receivables in arrears is partially attributable to the economic downturn starting in 2008 having a negative impact on customers' ability to pay their utility bills. Cinergy Receivables, Duke Energy Ohio, Duke Energy Kentucky and Duke Energy Indiana continue to monitor arrearages to determine whether an other-than-temporary impairment has occurred.

Duke Energy Ohio retains servicing responsibilities for its role as a collection agent on the amounts due on the sold receivables. However, Cinergy Receivables assumes the risk of collection on the purchased receivables without recourse to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky in the event of a loss. While no direct recourse to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky exists, these entities risk loss in the event collections are not sufficient to allow for full recovery of their retained interests. No servicing asset or liability is recorded since the servicing fee paid to Duke Energy Ohio approximates a market rate.

The carrying values of the retained interests are determined by allocating the carrying value of the receivables between the assets sold and the interests retained based on relative fair value. The key assumptions used in estimating the fair value for 2009 were an anticipated credit loss ratio of 0.6%, a discount rate of 2.7% and a receivable turnover rate of 11.6%. The key assumptions used in estimating the fair value for 2008 were an anticipated credit loss ratio of 0.6%, a discount rate of 5.3% and a receivable turnover rate of 11.4%. Because (i) the receivables generally turnover in less than two months, (ii) credit losses are reasonably predictable due to the broad customer base and lack of significant concentration, and (iii) the purchased beneficial interest is subordinate to all retained interests and thus would absorb losses first, the allocated bases of the subordinated notes are not materially different than their face value. The hypothetical effect on the fair value of the retained interests assuming both a 10% and a 20% unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history. Interest accrues to Duke Energy Ohio, Duke Energy Indiana and Duke Energy Kentucky on the retained interests using the accretable yield method, which generally approximates the stated rate on the notes since the allocated basis and the face value are nearly equivalent. Duke Energy records income from Cinergy Receivables in a similar manner. An impairment charge would be recorded against the carrying value of both the retained interests and purchased beneficial interest in the event it is determined that an other-than-temporary impairment has occurred.

The following table shows the gross and net receivables sold, retained interests, purchased beneficial interest, sales, and cash flows during the years ended December 31, 2009 and 2008:

(in millions)	2009	2008
Receivables sold as of December 31,	$ 619	$ 748
Less: Retained interests	340	292
Net receivables sold as of December 31,	$ 279	$ 456
Purchased beneficial interest	$ —	$ —
Sales		
Receivables sold	$ 5,506	$ 5,717
Loss recognized on sale	43	60
Cash flows		
Cash proceeds from receivables sold	$ 5,416	$ 5,664
Collection fees received	3	3
Return received on retained interests	27	37

Cash flows from the sale of receivables are reflected within Operating Activities on the Consolidated Statements of Cash Flows.

Collection fees received in connection with the servicing of transferred accounts receivable are included in Operation, maintenance and other on the Consolidated Statements of Operations.

The loss recognized on the sale of receivables is calculated monthly by multiplying the receivables sold during the month by the required discount which is derived monthly utilizing a three year weighted average formula that considers charge-off history, late charge history, and turnover history on the sold receivables, as well as a component for the time value of money. The discount rate, or component for the time value of money, is calculated monthly by summing the prior month-end LIBOR rate plus a fixed rate of 2.39%.

Duke Energy Receivables Finance Company.

See Note 15 for further information.

22. OTHER INCOME AND EXPENSES, NET

The components of Other Income and Expenses, net on the Consolidated Statements of Operations for the years ended December 31, 2009, 2008 and 2007 are as follows:

	For the years ended December 31,		
(in millions)	2009	2008	2007
Income/(Expense):			
Interest income	$ 77	$ 130	$ 192
Foreign exchange gains (losses)[a]	23	(20)	14
AFUDC equity	153	148	69
Deferred returns	(7)	(11)	(15)
Impairments of available-for-sale securities[b]	—	(13)	—
Other	38	(2)	11
Total	$284	$ 232	$ 271

(a) Primarily relates to International Energy's remeasurement of certain cash and debt balances into the functional currency.
(b) See Note 10 for additional information.

23. SUBSEQUENT EVENTS

For information on subsequent events related to regulatory matters, investments in unconsolidated affiliates and related party transactions, commitments and contingencies and variable interest entities, see Notes 4, 12, 16 and 21, respectively.

In January 2010, Duke Energy announced plans to offer a voluntary severance plan to approximately 8,750 eligible employees. As this is a voluntary plan, all severance benefits offered under this plan are considered special termination benefits under GAAP. Special termination benefits are measured upon employee acceptance and recorded immediately absent a significant retention period. If a significant retention period exists, the cost of the special termination benefits are recorded ratably over the remaining service periods of the affected employees. The window for employees to request to voluntarily end their employment under this plan opened on February 3, 2010 and closed on February 24, 2010 for approximately 8,400 eligible employees. For employees affected by the consolidation of Duke Energy's corporate functions in Charlotte, North Carolina, as discussed further below, the window will close March 31, 2010. Duke Energy currently estimates severance payments associated with this voluntary plan, based on employees' requests to voluntarily end their employment received through February 24, 2010, of approximately $130 million. However, until management of Duke Energy approves the requests, it reserves the right to reject any request to volunteer based on business needs and/or excessive participation.

In addition, in January 2010, Duke Energy announced that it will consolidate certain corporate office functions, resulting in transitioning over the next two years of approximately 350 positions from its offices in the Midwest to its corporate headquarters in Charlotte, North Carolina. Employees who do not relocate have the option to elect to participate in the voluntary plan discussed above, find a regional position within Duke Energy or remain with Duke Energy through a transition period, at which time a reduced severance benefit would be paid under Duke Energy's ongoing severance plan. Management cannot currently estimate the costs, if any, of severance benefits which will be paid to its employees due to this office consolidation.

Additionally, Duke Energy believes that it is possible that the voluntary severance plan may trigger settlement accounting or curtailment accounting with respect to its pension and other post-retirement benefit plans. At this time, management is unable to determine the likelihood that settlement or curtailment accounting will be triggered.

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

(in millions, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2009					
Operating revenues	$3,312	$2,913	$3,396	$3,110	$12,731
Operating income	681	528	445	595	2,249
Net income attributable to Duke Energy Corporation	344	276	109	346	1,075
Earnings per share:					
Basic[(a)]	$ 0.27	$ 0.21	$ 0.08	$ 0.26	$ 0.83
Diluted[(a)]	$ 0.27	$ 0.21	$ 0.08	$ 0.26	$ 0.83
2008					
Operating revenues	$3,337	$3,229	$3,508	$3,133	$13,207
Operating income	751	683	577	500	2,511
Income before extraordinary items	465	351	215	260	1,291
Net income attributable to Duke Energy Corporation	465	351	215	331	1,362
Earnings per share (before extraordinary items):					
Basic[(a)]	$ 0.37	$ 0.28	$ 0.17	$ 0.21	$ 1.03
Diluted[(a)]	$ 0.37	$ 0.28	$ 0.17	$ 0.21	$ 1.02
Earnings per share:					
Basic[(a)]	$ 0.37	$ 0.28	$ 0.17	$ 0.26	$ 1.08
Diluted[(a)]	$ 0.37	$ 0.28	$ 0.17	$ 0.26	$ 1.07

(a) Quarterly EPS amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.

During the first quarter of 2009, Duke Energy recorded the following unusual or infrequently occurring item: an approximate $33 million charge associated with performance guarantees issued on behalf of Crescent (see Note 17).

During the second quarter of 2009, Duke Energy recorded the following unusual or infrequently occurring item: an approximate $33 million charge associated with an adverse ruling on prior year's transmission fees in Brazil (see Note 16).

During the third quarter of 2009, Duke Energy recorded the following unusual or infrequently occurring items: an approximate $371 million non-cash goodwill impairment charge related to the non-regulated Midwest generation reporting unit to write-down the value of the goodwill to the estimated fair value (see Note 11); and an approximate $42 million of pre-tax impairment charges related to certain generating assets in the Midwest to write-down the value of these assets to their estimated fair value (see Note 11).

During the fourth quarter of 2009, Duke Energy recorded the following unusual or infrequently occurring item: an approximate $18 million pre-tax impairment charge to write-down the carrying value of International Energy's investment in Attiki (see Note 12).

During the first quarter of 2008, Duke Energy recorded the following unusual or infrequently occurring item: Duke Energy's proportionate share of impairment charges recorded by Crescent, which amounted to a pre-tax charge of approximately $11 million (see Note 12).

During the second quarter of 2008, Duke Energy recorded the following unusual or infrequently occurring items: Duke Energy's proportionate share of impairment charges recorded by Crescent, which amounted to a pre-tax charge of approximately $113 million (see Note 12); an approximate $23 million pre-tax gain related to the sale of Brownsville (see Note 13); and an approximate $4 million charge related to other-than-temporary impairment of investments in auction rate securities (see Note 10).

During the third quarter of 2008, Duke Energy recorded the following unusual or infrequently occurring items: Duke Energy's proportionate share of impairment charges recorded by Crescent, which amounted to a pre-tax charge of approximately $114 million (see Note 12); and an approximate $82 million pre-tax impairment charge related to emission allowances (see Note 11).

During the fourth quarter of 2008, Duke Energy recorded the following unusual or infrequently occurring item: an approximate $67 million after-tax (approximately $103 million pre-tax) extraordinary gain related to the reapplication of regulatory accounting treatment to certain operations of Commercial Power (see Note 1).

DUKE ENERGY CORPORATION

Schedule I — Condensed Parent Company Financial Statements

Condensed Statements of Operations

	Years Ended December 31,		
(in millions, except per-share amounts)	2009	2008	2007
Operating Revenues	$ —	$ —	$ 15
Operating Expenses	1	(4)	(1)
Operating (Loss) Income	(1)	4	16
Equity in Earnings of Subsidiaries	1,095	1,275	1,421
Other Income and Expenses, net	9	(8)	52
Interest Expense	99	42	23
Income Before Income Taxes	1,004	1,229	1,466
Income Tax Benefit	(59)	(50)	(56)
Income From Continuing Operations	1,063	1,279	1,522
Income (Loss) From Discontinued Operations, net of tax	12	16	(22)
Income Before Extraordinary Items	1,075	1,295	1,500
Extraordinary Items, net of tax	—	67	—
Net Income	$1,075	$1,362	$1,500

Common Stock Data

Earnings per share (from continuing operations)			
Basic	$ 0.82	$ 1.01	$ 1.21
Diluted	$ 0.82	$ 1.01	$ 1.20
Earnings (loss) per share (from discontinued operations)			
Basic	$ 0.01	$ 0.02	$ (0.02)
Diluted	$ 0.01	$ 0.01	$ (0.02)
Earnings per share (before extraordinary items)			
Basic	$ 0.83	$ 1.03	$ 1.19
Diluted	$ 0.83	$ 1.02	$ 1.18
Earnings per share (from extraordinary items)			
Basic	$ —	$ 0.05	$ —
Diluted	$ —	$ 0.05	$ —
Earnings per share			
Basic	$ 0.83	$ 1.08	$ 1.19
Diluted	$ 0.83	$ 1.07	$ 1.18
Dividends per share	$ 0.94	$ 0.90	$ 0.86
Weighted-average shares outstanding			
Basic	1,293	1,265	1,260
Diluted	1,294	1,267	1,265

DUKE ENERGY CORPORATION

Schedule I — Condensed Parent Company Financial Statements

Balance Sheets

	December 31,	
(in millions, except per-share amounts)	2009	2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 365	$ 5
Short-term investments	—	5
Receivables	1,240	894
Other	55	175
Total current assets	1,660	1,079
Investments and Other Assets		
Notes receivable	450	450
Investment in consolidated subsidiaries	23,361	21,814
Other	1,099	1,106
Total investments and other assets	24,910	23,370
Total Assets	$26,570	$24,449
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 102	$ 102
Notes payable and commercial paper	—	264
Taxes accrued	—	27
Other	71	92
Total current liabilities	173	485
Long-term Debt	2,971	1,224
Other Long-Term Liabilities		
Deferred income taxes	175	35
Other	1,501	1,717
Total other long-term liabilities	1,676	1,752
Commitments and Contingencies		
Common Stockholders' Equity		
Common Stock, $0.001 par value, 2 billion shares authorized; 1,309 million and 1,272 million shares outstanding at December 31, 2009 and December 31, 2008, respectively	1	1
Additional paid-in capital	20,661	20,106
Retained earnings	1,460	1,607
Accumulated other comprehensive loss	(372)	(726)
Total common stockholders' equity	21,750	20,988
Total Liabilities and Common Stockholders' Equity	$26,570	$24,449

DUKE ENERGY CORPORATION

Schedule I — Condensed Parent Company Financial Statements

Condensed Statements of Cash Flows

	Years Ended December 31,		
(in millions)	2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 1,075	$ 1,362	$ 1,500
Adjustments to reconcile net income to net cash (used in) provided by operating activities	(1,002)	(748)	(1,164)
Net cash (used in) provided by operating activities	73	614	336
CASH FLOWS FROM INVESTING ACTIVITIES			
Purchases of available-for-sale securities	—	(1,117)	(14,881)
Proceeds from sales and maturities of available-for-sale securities	17	1,367	15,740
Investment in wholly-owned subsidiary	(250)	—	(204)
Notes receivable from affiliates, net	(272)	(765)	(548)
Other	9	(19)	(7)
Net cash (used in) provided by investing activities	(496)	(534)	100
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from the:			
Issuance of long-term debt	1,740	771	—
Issuance of common stock related to employee benefit plans	519	133	50
Notes payable and commercial paper	(269)	112	561
Dividends paid	(1,222)	(1,143)	(1,089)
Other	15	27	21
Net cash provided by (used in) financing activities	783	(100)	(457)
Net increase (decrease) in cash and cash equivalents	360	(20)	(21)
Cash and cash equivalents at beginning of period	5	25	46
Cash and cash equivalents at end of period	$ 365	$ 5	$ 25

DUKE ENERGY CORPORATION

Schedule I — Condensed Parent Company Financial Statements

1. BASIS OF PRESENTATION

Duke Energy Corporation (Duke Energy) is a holding company that conducts substantially all of its business operations through its subsidiaries. As specified in the merger conditions issued by various state commissions in connection with Duke Energy's merger with Cinergy Corp. (Cinergy) in April 2006, there are restrictions on Duke Energy's ability to obtain funds from certain of its subsidiaries through dividends, loans or advances. For further information, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters." Accordingly, these condensed financial statements have been prepared on a parent-only basis. Under this parent-only presentation, Duke Energy's investments in its consolidated subsidiaries are presented under the equity method of accounting. In accordance with Rule 12-04 of Regulation S-X, these parent-only financial statements do not include all of the information and footnotes required by Generally Accepted Accounting Principles (GAAP) in the United States (U.S.) for annual financial statements. Because these parent-only financial statements and notes do not include all of the information and footnotes required by GAAP in the U.S. for annual financial statements, these parent-only financial statements and other information included should be read in conjunction with Duke Energy's audited Consolidated Financial Statements contained within Part II, Item 8 of this Form 10-K for the year ended December 31, 2009.

Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and foreign jurisdictional returns as required. The taxable income of Duke Energy's wholly-owned operating subsidiaries is reflected in Duke Energy's U.S. federal and state income tax returns. Duke Energy has a tax sharing agreement with its wholly-owned operating subsidiaries, where the separate return method is used to allocate tax expenses and benefits to the wholly-owned operating subsidiaries whose investments or results of operations provide these tax expenses and benefits. The accounting for income taxes essentially represents the income taxes that Duke Energy's wholly-owned operating subsidiaries would incur if each were a separate company filing its own tax return as a C-Corporation.

2. DEBT

Summary of Debt and Related Terms

(in millions)	Weighted-Average Rate	Year Due	December 31, 2009	2008
Unsecured debt	4.9%	2012 – 2019	$2,521	$ 774
Commercial paper[a]	0.4%		450	714
Total debt			2,971	1,488
Short-term notes payable and commercial paper			—	(264)
Total long-term debt			$2,971	$1,224

(a) Includes $450 million as of both December 31, 2009 and 2008 that was classified as Long-term Debt on the Consolidated Balance Sheets due to the existence of long-term credit facilities which back-stop these commercial paper balances, along with Duke Energy's ability and intent to refinance these balances on a long-term basis. The weighted-average days to maturity was 14 days as of December 31, 2009 and 10 days as of December 31, 2008.

At December 31, 2009, Duke Energy has guaranteed approximately $2.4 billion of debt issued by Duke Energy Carolinas, LLC, one of Duke Energy's wholly-owned operating subsidiaries.

In August 2009, Duke Energy issued $1 billion principal amount of senior notes, of which $500 million carry a fixed interest rate of 3.95% and mature September 15, 2014 and $500 million carry a fixed interest rate of 5.05% and mature September 15, 2019. Proceeds from the issuance were used to redeem commercial paper, to fund capital expenditures in Duke Energy's unregulated businesses in the U.S. and for general corporate purposes.

In January 2009, Duke Energy issued $750 million principal amount of 6.30% senior notes due February 1, 2014. Proceeds from the issuance were used to redeem commercial paper and for general corporate purposes.

In September 2008, Duke Energy borrowed approximately $274 million under its master credit facility and that amount remained outstanding as of December 31, 2009. For additional information on Duke Energy's master credit facility, see Note 15 to the Consolidated Financial Statements, 'Debt and Credit Facilities.' The loans under the master credit facility are revolving credit loans that currently bear interest at one-month LIBOR plus an applicable spread. The loan for Duke Energy has a stated maturity of June 2012.

In June 2008, Duke Energy issued $500 million principal amount of senior notes, of which $250 million carry a fixed interest rate of 5.65% and mature June 15, 2013 and $250 million carry a fixed interest rate of 6.25% and mature June 15, 2018. Proceeds from the issuance were used to redeem commercial paper, to fund capital expenditures in Duke Energy's unregulated businesses in the U.S. and for general corporate purposes.

Annual Maturities as of December 31, 2009

(in millions)	
2010	$ —
2011	—
2012	274
2013	249
2014	1,249
Thereafter	1,199
Total long-term debt, including current maturities	$2,971

DUKE ENERGY CORPORATION

Schedule I — Condensed Parent Company Financial Statements – (Continued)

3. COMMITMENTS AND CONTINGENCIES

Duke Energy and its subsidiaries are a party to litigation, environmental and other matters. For further information, see Note 16 to the Consolidated Financial Statements, "Commitments and Contingencies."

Duke Energy has various financial and performance guarantees and indemnifications which are issued in the normal course of business. These contracts include performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Duke Energy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. The maximum potential amount of future payments Duke Energy could have been required to make under these guarantees as of December 31, 2009 was approximately $4.3 billion. Of this amount, approximately $4.1 billion relates to guarantees of wholly-owned consolidated entities, including debt issued by Duke Energy Carolinas discussed above, and less than wholly-owned consolidated entities. The majority of these guarantees expire at various times between 2009 and 2033, with the remaining performance guarantees having no contractual expiration. See Note 17 to the Consolidated Financial Statements, "Guarantees and Indemnifications," for further discussion of guarantees issued on behalf of unconsolidated affiliates and third parties.

4. RELATED PARTY TRANSACTIONS

Balances due to or due from related parties included in the Balance Sheets as of December 31, 2009 and 2008 are as follows:

	December 31,	
(in millions)	2009	2008
Assets (Liabilities)		
Current assets due from affiliated companies[(a)(b)]	$ 78	$ 8
Current liabilities due to affiliated companies[(c)]	$(101)	$(100)
Non-current liabilities due to affiliated companies[(d)]	$(766)	$(766)

(a) Balance excludes assets or liabilities associated with money pool arrangements, which are discussed below.
(b) The balances at December 31, 2009 and 2008 are classified as Receivables on the Balance Sheets.
(c) The balances at December 31, 2009 and 2008 are classified as Accounts Payable on the Balance Sheets.
(d) The balances at December 31, 2009 and 2008 are classified as Other within Other Long-Term Liabilities on the Balance Sheets.

During 2007, Duke Energy began providing support to certain subsidiaries for their short-term borrowing needs through participation in a money pool arrangement. Under this arrangement, certain subsidiaries with short-term funds may provide short-term loans to affiliates participating under this arrangement. Additionally, Duke Energy provides loans to subsidiaries through the money pool, but is not permitted to borrow funds through the money pool arrangement. Duke Energy had receivables of approximately $1,135 million and $863 million as of December 31, 2009 and 2008, respectively, classified within Receivables in the accompanying Balance Sheets. Additionally, Duke Energy had money pool-related receivables of $450 million classified as Notes Receivable within Investments and Other Assets on the Balance Sheets as of both December 31, 2009 and 2008. The $272 million increase in money pool receivables during 2009 and the $765 million increase during 2008 are reflected as Notes Receivable from Affiliates, net within Net Cash (Used in) Provided by Investing Activities on the Condensed Statements of Cash Flows. In conjunction with the money pool arrangement, Duke Energy recorded interest income of approximately $12 million, $23 million and $16 million in 2009, 2008 and 2007, respectively, which is included in Other Income and Expenses, net on the Condensed Statements of Operations.

Duke Energy also provides funding to and sweeps cash from subsidiaries that do not participate in the money pool. For these subsidiaries, the cash is used in or generated from their operations, capital expenditures, debt payments and other activities. Amounts funded or received are carried as open accounts as either Investments and Advances to Consolidated Subsidiaries or as Other Non-Current Liabilities and do not bear interest. These amounts are included within Net Cash (Used in) Provided by Operating Activities on the Condensed Statements of Cash Flows.

Additionally, Duke Energy recorded $1 million of interest expense in 2007 associated with credit support provided to a subsidiary, which is included in Interest Expense on the Condensed Statements of Operations.

During the years ended December 31, 2009 and 2007, Duke Energy contributed approximately $250 million and $204 million, respectively, of capital to its wholly-owned subsidiary, Cinergy Corp. Additionally, Duke Energy received dividends from Cinergy Corp. of $200 million in 2008 and $135 million in 2007, which are reflected within Net Cash (Used in) Provided by Operating Activities on the Condensed Statements of Cash Flows.

DUKE ENERGY CORPORATION

Schedule II — Valuation and Qualifying Accounts and Reserve

		Additions:			
(in millions)	Balance at Beginning of Period	Charged to Expense	Charged to Other Accounts	Deductions[a]	Balance at End of Period
December 31, 2009:					
Injuries and damages	$1,035	$ —	$ —	$ 51	$ 984
Allowance for doubtful accounts	42	23	9	26	48
Other[b]	555	52	24	235	396
	$1,632	$ 75	$ 33	$312	$1,428
December 31, 2008:					
Injuries and damages	$1,086	$ —	$ —	$ 51	$1,035
Allowance for doubtful accounts	67	34	—	59	42
Other[b]	623	137	36	241	555
	$1,776	$171	$ 36	$351	$1,632
December 31, 2007:					
Injuries and damages	$1,184	$ 5	$ 16	$119	$1,086
Allowance for doubtful accounts	94	37	7	71	67
Other[b]	1,105	98	109	689	623
	$2,383	$140	$132	$879	$1,776

(a) Principally cash payments and reserve reversals. For 2007, this also includes the effects of amounts included in the spin-off of Spectra Energy Corp. (Spectra Energy) on January 2, 2007

(b) Principally nuclear property insurance reserves at Duke Energy Carolinas, insurance reserves at Bison Insurance Company Limited (Bison) and other reserves, included in Other within Current Liabilities or Other within Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

The valuation and reserve amounts above do not include unrecognized tax benefits amounts or deferred tax asset valuation allowance amounts.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by Duke Energy in the reports it files or submits under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported, within the time periods specified by the Securities and Exchange Commission's (SEC) rules and forms.

Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by Duke Energy in the reports it files or submits under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, Duke Energy has evaluated the effectiveness of its disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2009, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in providing reasonable assurance of compliance.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, Duke Energy has evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended December 31, 2009 and, other than the fourth quarter system changes described below, have concluded that no change has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

During the fourth quarter of 2009, Duke Energy implemented a new Enterprise Asset Management system used for asset management, work management and supply chain functions for its Midwest and corporate operations. Additionally, the Southeast operations implemented a new system for online customer billing and payment. These system changes are a result of an evaluation of the previous systems and related processes to support evolving operational needs, and are not the result of any identified deficiencies in the previous systems. Duke Energy reviewed the implementation effort as well as the impact on Duke Energy's internal control over financial reporting and where appropriate, made changes to internal controls over financial reporting to address these system changes.

Management's Annual Report On Internal Control Over Financial Reporting

Duke Energy's management is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with generally accepted accounting principles in the United States. Because of 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 policies and procedures may deteriorate.

Duke Energy's management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2009 based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2009.

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on the effectiveness of Duke Energy's internal control over financial reporting.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Reference to "Executive Officers of Duke Energy" is included in "Item 1. Business" of this report. Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2010 annual meeting of shareholders.

ITEM 11. EXECUTIVE COMPENSATION.

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2010 annual meeting of shareholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2010 annual meeting of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2010 annual meeting of shareholders.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

Information in response to this item is incorporated by reference to Duke Energy's Proxy Statement relating to Duke Energy's 2010 annual meeting of shareholders.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Consolidated Financial Statements, Supplemental Financial Data and Supplemental Schedules included in Part II of this annual report are as follows:

Duke Energy Corporation:

Consolidated Financial Statements

Consolidated Statements of Operations for the Years Ended December 31, 2009, 2008 and 2007

Consolidated Balance Sheets as of December 31, 2009 and 2008

Consolidated Statements of Cash Flows for the Years Ended December 31, 2009, 2008 and 2007

Consolidated Statements of Equity and Comprehensive Income for the Years ended December 31, 2009, 2008 and 2007

Notes to the Consolidated Financial Statements

Quarterly Financial Data, as revised (unaudited, included in Note 24 to the Consolidated Financial Statements)

Consolidated Financial Statement Schedule I — Condensed Parent Company Financial Information for the Years Ended December 31, 2009, 2008 and 2007

Consolidated Financial Statement Schedule II — Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 2009, 2008 and 2007

Report of Independent Registered Public Accounting Firm

(b) Exhibits — See Exhibit Index immediately following the signature page.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 26, 2010

DUKE ENERGY CORPORATION
(Registrant)

By: /s/ JAMES E. ROGERS

James E. Rogers
Chairman, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

(i) James E. Rogers*
Chairman, President and Chief Executive Officer (Principal Executive Officer and Director)

(ii) /s/ Lynn J. Good
Group Executive and Chief Financial Officer (Principal Financial Officer)

(iii) Steven K. Young*
Senior Vice President and Controller (Principal Accounting Officer)

(iv) William Barnet, III*
Director

G. Alex Bernhardt, Sr.*
Director

Michael G. Browning*
Director

Daniel R. DiMicco*
Director

John H. Forsgren*
Director

Ann M. Gray*
Director

James H. Hance, Jr.*
Director

E. James Reinsch*
Director

James T. Rhodes*
Director

Philip R. Sharp*
Director

Dudley S. Taft*
Director

Date: February 26, 2010

Lynn J. Good, by signing her name hereto, does hereby sign this document on behalf of the registrant and on behalf of each of the above-named persons previously indicated by asterisk pursuant to a power of attorney duly executed by the registrant and such persons, filed with the Securities and Exchange Commission as an exhibit hereto.

By: /s/ LYNN J. GOOD

Attorney-In-Fact

PART IV

EXHIBIT INDEX

Exhibits filed herewith are designated by an asterisk (*). All exhibits not so designated are incorporated by reference to a prior filing, as indicated. Items constituting management contracts or compensatory plans or arrangements are designated by a double asterisk (**). Portions of the exhibit designated by a triple asterisk (***) have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities and Exchange Act of 1934.

Exhibit Number	
2.1	Agreement and Plan of Merger, dated as of May 8, 2005, as amended as of July 11, 2005, as of October 3, 2005 and as of March 30, 2006, by and among the registrant, Duke Energy Corporation, Cinergy Corp., Deer Acquisition Corp., and Cougar Acquisition Corp. (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 4, 2006, as Exhibit 2-1).
2.2	Separation and Distribution Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with the Form 8-K of Duke Energy Corporation, File No. 1-32853, December 15, 2006, as Exhibit 2.1).
3.1	Amended and restated Certificate of Incorporation (filed with the Form 8-K of Duke Energy Corporation, File No. 1-32853, April 4, 2006, as Exhibit 3-1).
3.2	Amended and Restated By-Laws of registrant (filed with the Form 8-K of Duke Energy Corporation, File No. 1-32853, March 3, 2008, as Exhibit 3.1).
10.1	Purchase and Sale Agreement dated as of January 8, 2006, by and among Duke Energy Americas, LLC, and LSP Bay II Harbor Holding, LLC (filed with the Form 10-Q of the registrant for the quarter ended March 31, 2006, File No. 1-32853, as Exhibit 10.2).
10.1.1	Amendment to Purchase and Sale Agreement, dated as of May 4, 2006, by and among Duke Energy Americas, LLC, LS Power Generation, LLC (formerly known as LSP Bay II Harbor Holding, LLC), LSP Gen Finance Co, LLC, LSP South Bay Holdings, LLC, LSP Oakland Holdings, LLC, and LSP Morro Bay Holdings, LLC ((filed with the Form 10-Q of the registrant for the quarter ended March 31, 2006, File No. 1-32853, as Exhibit 10.2.1).
10.2 **	Directors' Charitable Giving Program (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 1992, File No. 1-4928, as Exhibit 10-P).
10.2.1**	Amendment to Directors' Charitable Giving Program dated June 18, 1997 (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-1.1).
10.2.2**	Amendment to Directors' Charitable Giving Program dated July 28, 1997 (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-1.2)
10.2.3**	Amendment to Directors' Charitable Giving Program dated February 18, 1998 (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2003, File No. 1-4928, as Exhibit 10-1.3).
10.3 **	Duke Energy Corporation 1998 Long-Term Incentive Plan, as amended (filed as Exhibit 1 to Schedule 14A of Duke Energy Carolinas, LLC, March 28, 2003, File No. 1-4928).
10.4 **	Duke Energy Corporation Executive Short-Term Incentive Plan (filed as Exhibit 2 to Schedule 14A of Duke Energy Carolinas, LLC, March 28, 2003, File No. 1-4928).
10.5 **	Duke Energy Corporation Executive Savings Plan, as amended and restated (filed with Form 8-K of Duke Energy Corporation, October 31, 2007, File No. 1-32853, as Exhibit 10.1).
10.6 **	Non-Qualified Option Agreement dated as of November 17, 2003 pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan, by and between Duke Energy Corporation and Paul M. Anderson (filed with Form 10-K of Duke Energy Carolinas, LLC for the year ended December 31, 2004, File No. 1-4928, as Exhibit 10-18.4).
10.7 **	Form of Phantom Stock Award Agreement dated February 28, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and each of Fred J. Fowler, David L. Hauser, Jimmy W. Mogg and Ruth G. Shaw (filed with the Form 8-K of Duke Energy Carolinas, LLC, File No. 1-4928, February 28, 2005, as Exhibit 10-2).
10.8 **	Form of Phantom Stock Award Agreement dated as of May 11, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and Jimmy W. Mogg. (filed with Form 10-Q of Duke Energy Carolinas, LLC for the quarter ended June 30, 2005, File No. 1-4928, as Exhibit 10-6)
10.9 **	Form of Phantom Stock Award Agreement dated as of May 12, 2005, pursuant to Duke Energy Corporation 1998 Long-Term Incentive Plan by and between Duke Energy Corporation and nonemployee directors (filed in Form 8-K of Duke Energy Carolinas, LLC, May 17, 2005, File No. 1-4928, as Exhibit 10-1).
10.10	Form of Phantom Stock Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 4, 2006, as Exhibit 10.1).
10.11	Form of Performance Share Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 4, 2006, as Exhibit 10.2).
10.12**	Employment Agreement between Duke Energy Corporation and James E. Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.1).

PART IV

Exhibit Number	
10.12.1**	Performance Award Agreement between Duke Energy Corporation and James E. Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.2).
10.12.2**	Phantom Stock Grant Agreement between Duke Energy Corporation and James E. Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.3).
10.13 **	Form Phantom Stock Award Agreement and Election to Defer (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, May 16, 2006, as Exhibit 10.1).
10.14	Agreements with Piedmont Electric Membership Corporation, Rutherford Electric Membership Corporation and Blue Ridge Electric Membership Corporation to provide wholesale electricity and related power scheduling services from September 1, 2006 through December 31, 2021 (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No. 1-32853, as Exhibit 10.15).
10.15	Purchase and Sale Agreement by and among Cinergy Capital & Trading, Inc., as Seller, and Fortis Bank, S.A./N.V., as Buyer, dated as of June 26, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, June 30, 2006, as Exhibit 10.1).
10.16 **	Form of Amendment to Performance Award Agreement and Phantom Stock Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, August 24, 2006, as Exhibit 10.1).
10.17 **	Form of Amendment to Phantom Stock Award Agreement (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, August 24, 2006, as Exhibit 10.2).
10.18	Formation and Sale Agreement by and among Duke Ventures, LLC, Crescent Resources, LLC, Morgan Stanley Real Estate Fund V U.S. L.P., Morgan Stanley Real Estate Fund V Special U.S., L.P., Morgan Stanley Real Estate Investors V U.S., L.P., MSP Real Estate Fund V, L.P., and Morgan Stanley Strategic Investments, Inc., dated as of September 7, 2006 (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2006, File No. 1-32853, as Exhibit 10.3).
10.19	Fifteenth Supplemental Indenture, dated as of April 3, 2006, among the registrant, Duke Energy and JPMorgan Chase Bank, N.A. (as successor to Guaranty Trust Company of New York), as trustee (the "Trustee"), supplementing the Senior Indenture, dated as of September 1, 1998, between Duke Energy Carolinas, LLC (formerly Duke Energy Corporation) and the Trustee (filed with the Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2006, File No. 1-32853, as Exhibit 10.1).
10.19.1	Stock Option Grant Agreement between Duke Energy Corporation and James E. Rogers, dated April 4, 2006 (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, April 6, 2006, as Exhibit 10.4).

Exhibit Number	
10.20 **	Duke Energy Corporation 2006 Long-Term Incentive Plan (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, October 27, 2006, as Exhibit 10.1).
10.21	Tax Matters Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, December 15, 2006, as Exhibit 10.1).
10.22	Transition Services Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, December 15, 2006, as Exhibit 10.2).
10.22.1	Amendment No. 1 to the Transition Services Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp. (filed in Form 10-Q of Duke Energy Corporation for the quarter ended March 31, 2007, File No. 1-32853, as Exhibit 10.4).
10.22.2	Amendment No. 2 to the Transition Services Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp. (filed in Form 10-Q of Duke Energy Corporation for the quarter ended March 31, 2007, File No. 1-32853, as Exhibit 10.5).
10.22.3	Amendment No. 3 to the Transition Services Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp. (filed in Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2007, File No. 1-32853, as Exhibit 10.3).
10.22.4	Amendment No. 4 to the Transition Services Agreement, dated as of June 30, 2007, by and between Duke Energy Corporation and Spectra Energy Corp. (filed in Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2007, File No. 1-32853, as Exhibit 10.1).
10.23	Employee Matters Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp. (filed with Form 8-K of Duke Energy Corporation, File No. 1-32853, December 15, 2006, as Exhibit 10.3).
10.24	First Amendment to Employee Matters Agreement, dated as of September 28, 2007 (filed in Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2007, File No. 1-32853, as Exhibit 10.3).
10.25 **	Duke Energy Corporation Directors' Savings Plan I & II, as amended and restated (filed with Form 8-K of Duke Energy Corporation, dated October 31, 2007, File No. 1-4298, as Exhibit 10.2).
10.26 **	Form of Phantom Stock Award Agreement (filed in Form 8-K of Duke Energy Corporation, March 8, 2007, File No. 1-32853, as item 10.01).

PART IV

Exhibit Number	
10.27 **	Form of Performance Share Award Agreement (filed in Form 8-K of Duke Energy Corporation, March 8, 2007, File No. 1-32853, as item 10.02).
10.28	Separation and Distribution Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp. (filed in Form 8-K of Duke Energy Corporation, File No. 1-32853, December 15, 2006, as item 2.1).
10.28.1	Amendment No. 1 to the Separation and Distribution Agreement, dated as of December 13, 2006, by and between Duke Energy Corporation and Spectra Energy Corp. (filed in Form 10-Q of Duke Energy Corporation for the quarter ended March 31, 2007, File No 1-32853, as Exhibit 10.3).
10.29 **	Amendment to the Duke Energy Corporation 1998 Long-Term Incentive Plan, effective as of February 27, 2007, by and between Duke Energy Corporation and Spectra Energy Corp. (filed in Form 10-Q of Duke Energy Corporation for the quarter ended March 31, 2007, File No. 1-32853, as Exhibit 10.6).
10.30 **	Amendment to the Duke Energy Corporation 2006 Long-Term Incentive Plan, effective as of February 27, 2007, by and between Duke Energy Corporation and Spectra Energy Corp. (filed in Form 10-Q of Duke Energy Corporation for the quarter ended March 31, 2007, File No. 1-32853, as Exhibit 10.7).
10.31	$2,650,000,000 Amended and Restated Credit Agreement, dated as of June 28, 2007, among Duke Energy Corporation, Duke Energy Carolinas, LLC, Duke Energy Ohio, Inc., Duke Energy Indiana, Inc. and Duke Energy Kentucky, Inc., as Borrowers, the banks listed therein, Wachovia Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, National Association, Barclays Bank PLC, Bank of America, N.A. and Citibank, N.A., as Co-Syndication Agents and The Bank of Tokyo-Mitsubishi, Ltd., New York Branch and Credit Suisse, as Co-Documentation Agents (filed in Form 8-K of Duke Energy Corporation, July 5, 2007, File No. 1-32853, as Exhibit 10.1; the agreement was executed June 28).
10.31.1	Amendment No. 1 to Amended and Restated Credit Agreement (filed in Form 8-K of Duke Energy Corporation, March 12, 2008, File No. 1-32853, as Exhibit 10.1).
10.32	Engineering, Procurement and Construction Agreement, dated July 11, 2007, by and between Duke Energy Carolinas, LLC and Stone & Webster National Engineering P.C. (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (filed in Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2007, File No. 1-32853, as Exhibit 10.2)

Exhibit Number	
10.33**	Change in Control Agreement by and between Duke Energy Corporation and James L. Turner, dated April 4, 2006 (filed with Form 10-K of Duke Energy Corporation for the year ended December 31, 2007, File No. 1-32853, as Exhibit 10.64.1).
10.34 **	Change in Control Agreement by and between Duke Energy Corporation and Marc E. Manly, dated April 4, 2006 (filed with Form 10-K of Duke Energy Corporation for the year ended December 31, 2007, File No. 1-32853, as Exhibit 10.66.1).
10.35	Amended and Restated Engineering, Procurement and Construction Agreement, dated February 20, 2008, by and between Duke Energy Carolinas, LLC and Stone & Webster National Engineering P.C. (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (filed in Form 10-Q of Duke Energy Corporation for the quarter ended March 31, 2008, File No. 1-32853, as Exhibit 10.1).
10.36**	Form of Phantom Stock Agreement (filed on Form 8-K of Duke Energy Corporation, February 22, 2008, File No. 1-32853, as Exhibit 10.1).
10.37**	Form of Performance Share Agreement (filed on Form 8-K of Duke Energy Corporation, February 22, 2008, File No. 1-32853, as Exhibit 10.2).
10.38	Amendment No. 1 to the Amended and Restated Credit Agreement (filed on Form 8-K of Duke Energy Corporation, March 12, 2008, File No. 1- 32853, as Exhibit 10.1).
10.39**	Summary of Director Compensation Program (filed in Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2008, File No. 1-32853, as Exhibit 10.1).
10.40	Agreement and Plan of Merger by and among DEGS Wind I, LLC, DEGS Wind Vermont, Inc., Catamount Energy Corporation (filed in Form 10-Q of Duke Energy Corporation for the quarter ended June 30, 2008, File No. 1-32853, as Exhibit 10.2).
*10.41***	Amended and Restated Engineering and Construction Agreement, dated as of December 21, 2009, by and between Duke Energy Carolinas, LLC and Shaw North Carolina, Inc.
10.42	Operating Agreement of Pioneer Transmission, LLC (filed in Form 10-Q of Duke Energy Corporation for the quarter ended September 30, 2008, File No. 1-32583, as Exhibit 10.1).

PART IV

Exhibit Number	
10.43**	Amendment to Duke Energy Corporation Executive Savings Plan, effective as of August 26, 2008 (filed on Form 8-K of Duke Energy Corporation, September 2, 2008, File No. 1-32583, as Exhibit 10.1).
10.44**	Duke Energy Corporation Executive Cash Balance Plan, as Amended and Restated Effective August 26, 2008 (filed on Form 8-K of Duke Energy Corporation, September 2, 2008, File No. 1-32583, as Exhibit 10.2).
10.45**	Amendment to Employment Agreement with James E. Rogers, effective as of August 26, 2008 (filed on Form 8-K of Duke Energy Corporation, September 2, 2008, File No. 1-32583 as Exhibit 10.3).
10.46**	Form of Amended and Restated Change in Control Agreement, effective as of August 26, 2008 (filed on Form 8-K of Duke Energy Corporation, September 2, 2008, File No. 1-32583 as Exhibit 10.4).
10.47**	Amendment to Phantom Stock and Performance Awards with James E. Rogers, effective as of august 26, 2008 (filed on Form 8-K of Duke Energy Corporation September 2, 2008, File No. 1-32853, as Exhibit 10.5).
10.48**	Amendment to Deferred Compensation Agreement with James E. Rogers, effective as of August 26, 2008 (filed on Form 8-K of Duke Energy Corporation, September 2, 2008, File No. 1-32583, as Exhibit 10.6).
10.49**	Amendment to Award Agreements pursuant to the Long-Term Incentive Plans (Employees), effective as of August 26, 2008 (filed on Form 8-K of Duke Energy Corporation, September 2, 2008, File No. 1-32583, as Exhibit 10.7).
10.50**	Amendment to Award Agreements pursuant to the Long-Term Incentive Plans (Directors), effective as of August 26, 2008 (filed on Form 8-K of Duke Energy Corporation, September 2, 2008, File No 1-32583, as Exhibit 99.1).
10.51**	Amendment to Duke Energy Corporation Directors' Savings Plan, effective as of August 26, 2008 (filed on Form 8-K of Duke Energy Corporation, September 2, 2008, File No. 1-32583, as Exhibit 99.2).
10.52**	Deferred Compensation Agreement dated December 16, 1992, between PSI Energy, Inc. and James E. Rogers, Jr.
10.53	Engineering, Procurement and Construction Management Agreement dated December 15, 2008 between Duke Energy Indiana, Inc. and Bechtel Power Corporation. (Portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended).
10.54	Retirement Agreement by and between Duke Energy Business Services LLC and David L. Hauser, effective as of June 22, 2009 (filed on Form 8-K of Duke Energy Corporation, June 26, 2009, File No. 1-32853, as Exhibit 99.1).
*12	Computation of Ratio of Earnings to Fixed Charges.
*21	List of Subsidiaries.
*23.1	Consent of Independent Registered Public Accounting Firm.
*24.1	Power of attorney authorizing Lynn J. Good and others to sign the annual report on behalf of the registrant and certain of its directors and officers.
*24.2	Certified copy of resolution of the Board of Directors of the registrant authorizing power of attorney.
*31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Financials in XBRL Format

The total amount of securities of the registrant or its subsidiaries authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to it.

Investor Information

Annual Meeting
The 2010 Annual Meeting of Duke Energy Shareholders will be:

Date: Thursday, May 6, 2010
Time: 10 a.m.
Place: O.J. Miller Auditorium
Energy Center
526 South Church Street
Charlotte, NC 28202

Shareholder Services
Shareholders may call [illegible] with questions about their stock accounts, legal transfer requirements, address changes, replacement dividend checks, replacement of lost certificates or other services. Additionally, registered shareholders can view their account online through DUK-OnLine, available at www.duke-energy.com.

Send written requests to:
Investor Relations
Duke Energy
P.O. Box 1005
Charlotte, NC 28201-1005

For electronic correspondence, visit
www.duke-energy.com/investors/contactIR

Stock Exchange Listing
Duke Energy's common stock is listed on the New York Stock Exchange. The company's common stock trading symbol is DUK.

Web Site Addresses
Corporate home page
www.duke-energy.com
Investor Relations
www.duke-energy.com/investors

InvestorDirect Choice Plan
The InvestorDirect Choice Plan provides a simple and convenient way to purchase common stock directly through the company, without incurring brokerage fees. Purchases may be made weekly. Bank drafts for monthly purchases, as well as a safekeeping option for depositing certificates into the plan, are available.

The plan also provides for full reinvestment, direct deposit or cash payment of dividends. Additionally, participants may register for DUK-OnLine, our online account management service.

Financial Publications
Duke Energy's annual report and other financial publications can be found on our Web site at www.duke-energy.com/investors. Printed copies are also available free of charge upon request.

Duplicate Mailings
If your shares are registered in different accounts, you may receive duplicate mailings of annual reports, proxy statements and other shareholder information. Call Investor Relations for instructions on eliminating duplications or combining your accounts.

Transfer Agent and Registrar
Duke Energy maintains shareholder records and acts as transfer agent and registrar for the company's common stock.

Dividend Payment
Duke Energy has paid quarterly cash dividends on its common stock for 84 consecutive years. For the remainder of 2010, dividends on common stock are expected to be paid, subject to declaration by the Board of Directors, on June 16, Sept. 16 and Dec. 16, 2010.

Bond Trustee
If you have questions regarding your bond account, call 800-254-2826, or write to:
The Bank of New York Mellon
Global Trust Services
101 Barclay Street – 21st Floor
New York, NY 10286

Send Us Feedback
We welcome your opinion of this annual report. Please visit www.duke-energy.com/investors, where you can view and provide feedback on both the print and online versions of this report. Or contact Investor Relations directly. Duke Energy is an equal opportunity employer. This report is published solely to inform shareholders and is not to be considered an offer, or the solicitation of an offer, to buy or sell securities.

[illegible]

Duke Energy®

526 South Church Street
Charlotte, NC 28202-1802
www.duke-energy.com

OUR MISSION

At Duke Energy, we make people's lives better by providing gas and electric services in a sustainable way — affordable, reliable and clean. This requires us to constantly look for ways to improve, to grow and to reduce our impact on the environment.

OUR VALUES

Caring: We look out for each other. We strive to make the environment and communities around us better places to live.

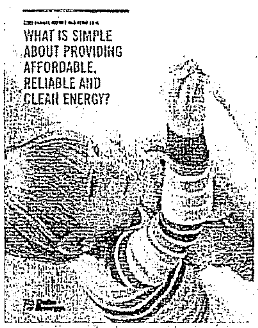
Openness: We're open to change and to new ideas from our co-workers, customers and other stakeholders. We explore ways to grow our business and make it better.

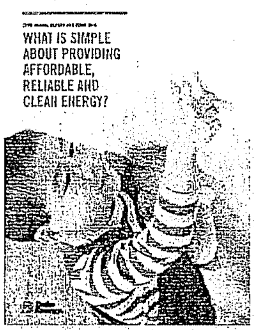
Respect: We value diverse talents, perspectives and experiences. We treat others the way we want to be treated.

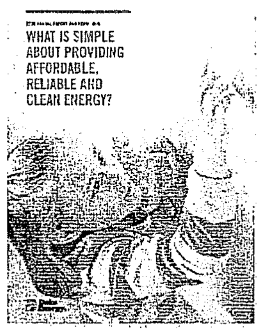
Integrity: We do the right thing. We honor our commitments. We admit when we're wrong.

Passion: We're passionate about what we do. We strive for excellence. We take personal accountability for our actions.

Safety: We put safety first in all we do.







ABOUT THE COVERS

Our children remind us that being concerned about the future has to be part of providing affordable, reliable and cleaner energy today. From left: Jack Hamel, 3, is the son of Stuart Hamel, manager of Valuation and Market Analysis for Duke Energy International. Ty Bailey, 5, is the son of Irene Chin, manager, Information Technology Support. Kennedy Ray, 4, is the daughter of Susan Ray, director, Risk Management for Duke Energy International.

Duke Energy

Investors

Nuclear

Catawba Nuclear Station

- Capacity: 2,258 megawatts
- Location: York County, South Carolina
- Commercial Date: 1985

McGuire Nuclear Station

- Capacity: 2,200 megawatts
- Location: Mecklenburg County, North Carolina
- Commercial Date: 1981

Oconee Nuclear Station

- Capacity: 2,538 megawatts
- Location: Oconee County, South Carolina
- Commercial Date: 1973

Nuclear Generation Fact Sheet (pdf, 103 KB)

Generating Electricity with Nuclear Power

Nuclear Emergency Preparedness

Nuclear Security

New Generation

NuStart Energy Consortium

Duke Energy

Investors

Coal-Fired

Allen Steam Station

- Capacity: 1,140 megawatts
- Location: Gaston County, North Carolina
- Commercial Date: 1957

Belews Creek Steam Station

- Capacity: 2,240 megawatts
- Location: Stokes County, North Carolina
- Commercial Date: 1974

Buck Steam Station

- Capacity: 369 megawatts
- Location: Rowan County, North Carolina
- Commercial Date: 1926

Cayuga Station

- Capacity: 1,104 megawatts
- Location: Vermillion County, Indiana
- Commercial Date: 1970

Cliffside Steam Station

- Capacity: 760 megawatts
- Location: Cleveland and Rutherford counties, North Carolina
- Commercial Date: 1940

Dan River Steam Station

- Capacity: 276 megawatts
- Location: Rockingham County, North Carolina
- Commercial Date: 1949

East Bend Station

- Capacity: 650 megawatts
- Location: Boone County, Kentucky
- Commercial Date: 1981

Edwardsport Station

- Capacity: 160 megawatts
- Location: Knox County, Indiana
- Commercial Date: 1918

Gallagher Station

- Capacity: 560 megawatts
- Location: Floyd County, Indiana
- Commercial Date: 1958

Gibson Station

- Capacity: 3,145 megawatts
- Location: Gibson County, Indiana
- Commercial Date: 1976

Lee Steam Station

- Capacity: 370 megawatts
- Location: Anderson County, South Carolina
- Commercial Date: 1951

Marshall Steam Station

- Capacity: 2,090 megawatts
- Location: Catawba County, North Carolina
- Commercial Date: 1965

Riverbend Steam Station

- Capacity: 454 megawatts
- Location: Gaston County, North Carolina
- Commercial Date: 1929

Wabash River Station

- Capacity: 668 megawatts
- Location: Vigo County, Indiana
- Commercial Date: 1953

Air Quality

Generating Electricity with Coal

Coal, Oil and Gas Fact Sheet (pdf, 113 KB)

New Generation

Duke Energy

Investors

Conventional Hydro

Bridgewater Hydro Station

- Capacity: 20 megawatts
- Location: McDowell and Burke counties, North Carolina
- Commercial Date: 1919

Rhodhiss Hydro Station

- Capacity: 26 megawatts
- Location: Caldwell County, North Carolina
- Commercial Date: 1925

Oxford Hydro Station

- Capacity: 36 megawatts
- Location: Catawba County, North Carolina
- Commercial Date: 1928

Lookout Shoals Hydro Station

- Capacity: 26 megawatts
- Location: Iredell County, North Carolina
- Commercial Date: 1915

Cowans Ford Hydro Station

- Capacity: 350 megawatts
- Location: Lincoln County, North Carolina
- Commercial Date: 1963

Mountain Island Hydro Station

- Capacity: 60 megawatts
- Location: Gaston County, North Carolina
- Commercial Date: 1923

Lake Wylie Hydro Station

- Capacity: 60 megawatts
- Location: York County, South Carolina & Mecklenburg County, North Carolina
- Commercial Date: 1925

Fishing Creek Hydro Station

- Capacity: 37 megawatts
- Location: Chester, South Carolina
- Commercial Date: 1916

Great Falls & Dearborn Hydro Stations

- Capacity: Great Falls: 24 megawatts; Dearborn: 46 megawatts
- Location: Chester, South Carolina
- Commercial Date: Great Falls 1907; Dearborn: 1923

Rocky Creek & Cedar Creek Hydro Stations

- Capacity: Rocky Creek: 28 megawatts; Cedar Creek: 45 megawatts
- Location: Fairfield and Lancaster counties, South Carolina
- Commercial Date: Rocky Creek: 1909; Cedar Creek: 1926

Wateree Hydro Station

- Capacity: 56 megawatts
- Location: Fairfield and Kershaw counties, South Carolina
- Commercial Date: 1919

Keowee Hydro Station

- Capacity: 158 megawatts
- Location: Pickens County, South Carolina
- Commercial Date: 1971

Markland Hydro Station

- Capacity: 65 megawatts
- Location: Switzerland County, Indiana
- Commercial Date: 1967

Other Hydro Stations

Nantahala Area Stations

Generating Electricity with Conventional Hydro

New Generation

Duke Energy

Investors

Oil / Gas-Fired

Buzzard Roost Station

- Capacity: 196 megawatts
- Location: Chappells, South Carolina
- Commercial Date: 1971

Cayuga Combustion Turbine Station

- Capacity: 110 megawatts
- Location: Cayuga, Indiana
- Commercial Date: 1993

Connersville Peaking Station

- Capacity: 98 megawatts
- Location: Fayette County, Indiana
- Commercial Date: 1972

Henry County Peaking Station

- Capacity: 129 megawatts
- Location: Henry County, Indiana
- Commercial Date: 2001

Lincoln Combustion Turbine Station

- Capacity: 1,200 megawatts
- Location: Lincoln County, North Carolina
- Commercial Date: 1995

Madison Peaking Station

- Capacity: 677 megawatts
- Location: Butler County, Ohio
- Commercial Date: 2000

Miami-Wabash Peaking Station

- Capacity: 104 megawatts
- Location: Wabash County, Indiana
- Commercial Date: 1968

Mill Creek Combustion Turbine Station

- Capacity: 640 megawatts
- Location: Cherokee County, South Carolina
- Commercial Date: 2003

Noblesville Station

- Capacity: 300 megawatts
- Location: Hamilton County, Indiana
- Commercial Date: 1950

Rockingham Station

- Capacity: 825 megawatts
- Location: Rockingham County, North Carolina
- Commercial Date: 2000

Wabash River Repowering Station

- Capacity: 280 megawatts
- Location: West Terre Haute, Indiana
- Commercial Date: 1995

Wheatland Peaking Station

- Capacity: 480 megawatts
- Location: Knox County, Indiana
- Commercial Date: 2000

Woodsdale Station

- Capacity: 504 megawatts
- Location: Butler County, Ohio
- Commercial Date: 1992

Generating Electricity with Oil or Gas

Coal, Oil and Gas Fact Sheet (pdf, 113 KB)

New Generation

Duke Energy

Investors

Pumped-Storage Hydro

Bad Creek Pumped-Storage Generating Station

- Capacity: 1,065 megawatts
- Location: Oconee County, South Carolina
- Commercial Date: 1991

Jocassee Pumped-Storage Generating Station

- Capacity: 610 megawatts
- Location: Pickens County, South Carolina
- Commercial Date: 1973

Generating Electricity with Pumped-Storage Hydro

New Generation

Duke Energy

Investors

Wholesale Power Generation

Duke Energy has approximately 7,600 megawatts of wholesale generation in the United States, primarily in the Midwest. A diverse mix of oil, coal and gas-fired facilities include:

Hanging Rock Energy Facility (Natural Gas)

- 1,240 megawatts
- Ironton, Ohio

Washington Energy Facility (Natural Gas)

- 620 megawatts
- Beverly, Ohio

Beckjord Station (Coal)

- 862 megawatts
- New Richmond, Ohio

Beckjord Station (Oil)

- 244 megawatts
- New Richmond, Ohio

Conesville Station (Coal)

- 312 megawatts
- Conesville, Ohio

Dicks Creek (Natural Gas)

- 172 megawatts
- Middletown, Ohio

Killen Station (Coal)

- 198 megawatts
- Wrightsville, Ohio

Stuart Station (Coal)

- 912 megawatts
- Aberdeen, Ohio

Miami Fort Station (Coal)

- 720 megawatts
- North Bend, Ohio

Miami Fort Station (Oil)

- 80 megawatts

- North Bend, Ohio

Zimmer Generating Station (Coal)

- 605 megawatts
- Moscow, Ohio

Fayette Energy Facility (Natural Gas)

- 620 megawatts
- Masontown, Pa.

Vermillion Energy Facility (Natural Gas)

- 480 megawatts
- Cayuga, Ind.

Lee Energy Facility (Natural Gas)

- 640 megawatts
- Dixon, Ill.

MANAGING THE PRESENT.

CREATING THE FUTURE.

THE POWER TO DO BOTH.

2009 Annual Report and Notice of Annual Meeting and Proxy Statement

Progress Energy

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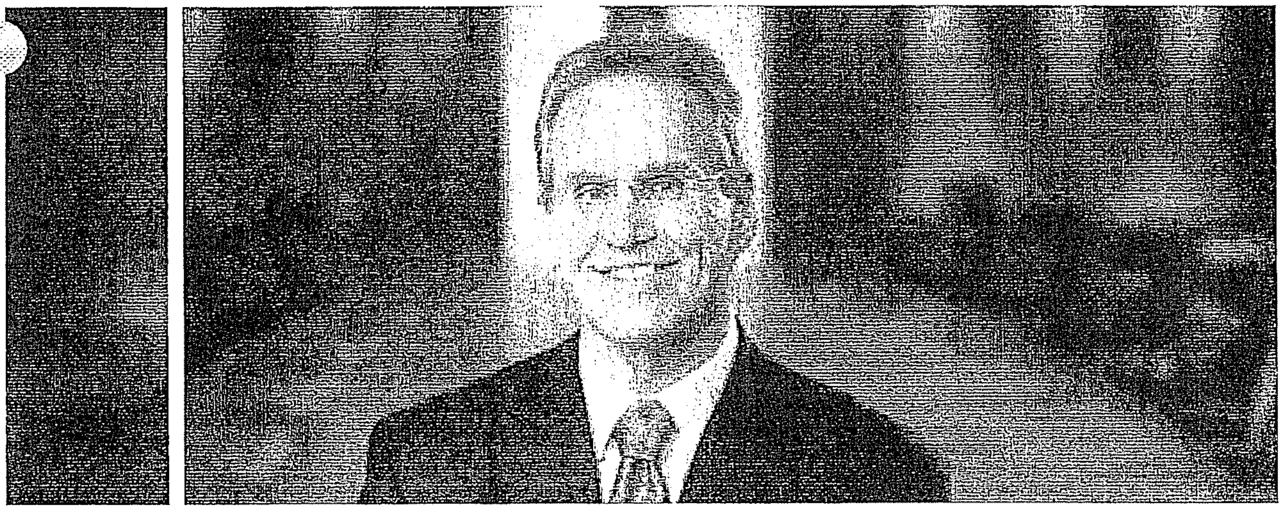
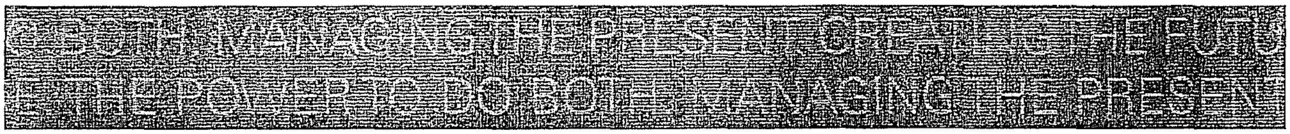
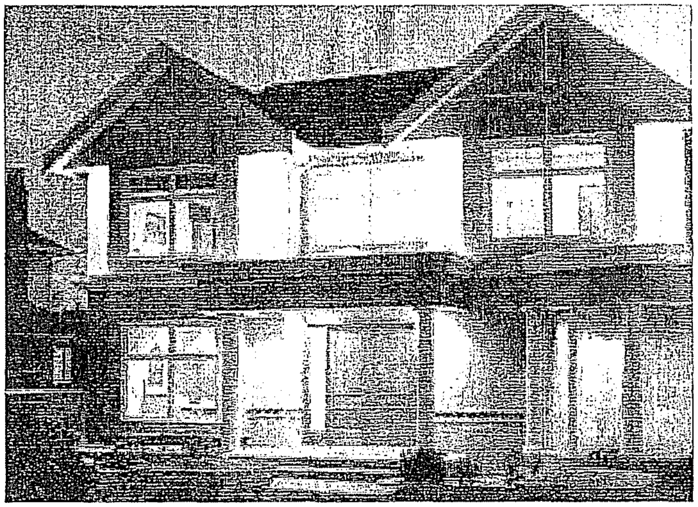
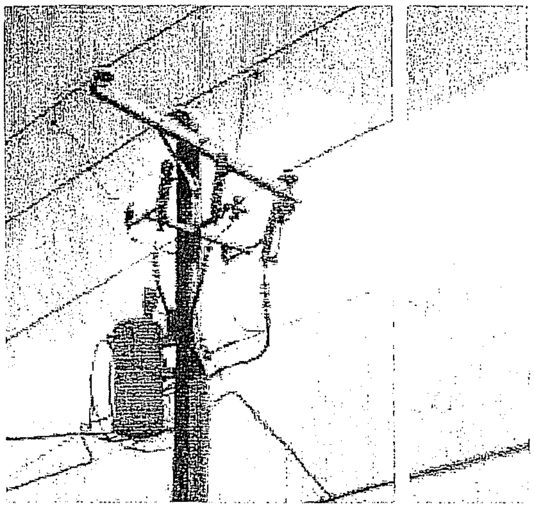


a message from our CEO

DEAR SHAREHOLDERS: Progress Energy lived up to its commitments in 2009 despite the hard economic realities in our nation and region. We delivered reliable, responsive service to customers and solid results to shareholders. Now, we are focused on effectively managing through the challenges and uncertainties of 2010 while taking important steps to create a successful future for our communities and company.







This report to you in early spring 2010 comes as our nation is slowly climbing out of a deep economic recession. Most of us, no doubt, have gained a new understanding of volatility and financial risk since late 2008, whether as an investor, a business owner or an individual trying to make a living.

I am proud of the way our employees and management team are handling these turbulent times. We are being both steady in the present storm and forward looking – controlling what we can control, aggressively managing costs and preparing for the future. We always keep in mind that millions of people count on us for an essential service or a quarterly dividend (in many cases, both), and for being a responsible corporate citizen.

Delivering reliable results

Progress Energy posted good financial results in a challenging year. We delivered a 10 percent total return to shareholders in 2009 and achieved ongoing earnings per share in our original targeted range for the fourth year in a row. Our company also has maintained its long record of commitment to the dividend, paying a dividend for more than 250 consecutive quarters.

Throughout this period, our two electric utilities – Progress Energy Carolinas and Progress Energy Florida – have continued to excel in our core mission of serving customers. This winter we met the challenge of extreme cold and record-breaking peak demand in the Carolinas and Florida and mobilized effectively to deal with severe storms, creatively using Twitter and other social media to provide timely updates.

We also brought into service additional peaking-generation capacity in North Carolina and completed a major oil-to-gas repowering project in Florida. This Bartow modernization project last summer was an outstanding success in terms of project management, capacity expansion and emissions reduction.

Our company recently received positive external recognition for environmental stewardship and customer service. Progress Energy was named to the Dow Jones Sustainability Index for the fifth consecutive year, and Progress Energy Carolinas was ranked number one in customer satisfaction in the South region for the second year in a row – number one among large utilities nationally – in the latest J.D. Power and Associates survey of utilities' business customers.

TH MANAGING THE PRESENT CREATING THE FUTURE
THE POWER TO DO BOTH MANAGING THE PRESENT CR

Managing the present

The financial pressure on our company has gone up another notch or two in 2010 because of a disappointing Florida rate decision early in the year and a still-sluggish economy throughout the nation. These events inevitably affect our earnings and cash flow and have caught the attention of the credit-rating agencies.

In response, we are redoubling our belt-tightening this year: maintaining the dividend, streamlining maintenance, scaling back capital spending and reducing merit and variable-performance pay increases for employees (in fact, no merit pay increase for executives and managers in 2010). This is a shared-sacrifice approach that's neither desirable nor sustainable for long but is necessary for now.

We are also evaluating our regulatory and financial options in Florida and are continuing to do our part to foster a constructive Florida regulatory climate that will enable us to attract the capital required to meet our customer and environmental obligations. Also of note in Florida is the extended repair outage at our Crystal River Nuclear Plant, which we expect to complete midyear.

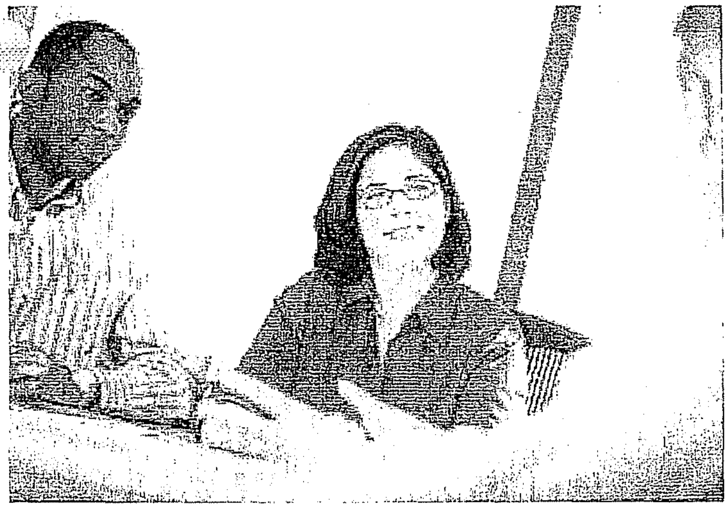
We are managing these and other challenges in a disciplined way to avoid compromising safety or operational excellence. In this business, we can't afford to be reckless or short-sighted.

Creating the future

At Progress Energy, we believe strongly in the long-term growth prospects of the communities we serve in the Carolinas and Florida. An improving national economy and housing market will enable more people to move to our service areas and more businesses to invest and expand here. So, even as we are making the tough choices to manage today's realities, we are carefully laying the groundwork for the higher growth and better future we see coming.

We intend to remain attractive to the buy-and-hold investors who represent the core of our shareholder base. This investor confidence is essential for us to fund the projects needed to be ready for a growing population and expanding economy as well as to meet the requirements of new energy and environmental policies.

National and state energy policies remain in flux, especially the rules to reduce greenhouse gas emissions and address global climate change. This prolonged uncertainty greatly



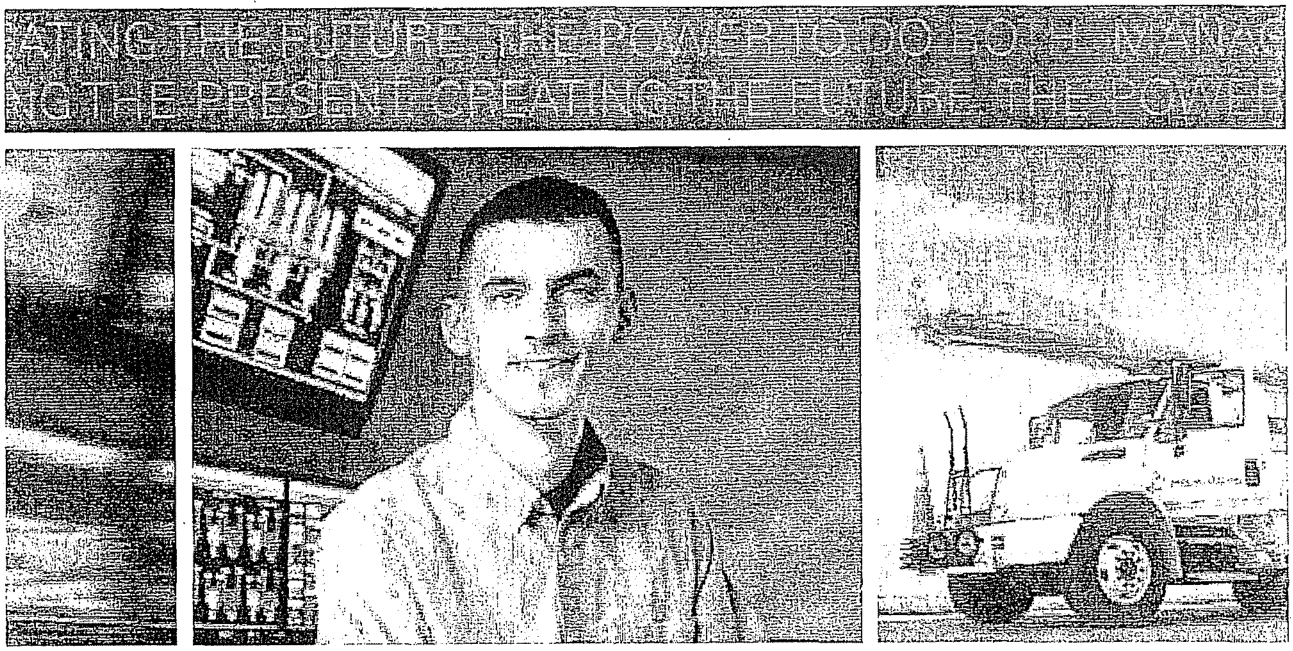
complicates utility planning, but there is a clear sense that clean-energy technologies ranging from renewable to nuclear must be a growing part of our nation's energy future.

Aligned with this direction, we developed a Balanced Solution strategy several years ago. It is a flexible portfolio approach that covers a broad spectrum of initiatives: aggressive energy-efficiency programs, innovative alternative energy projects (e.g., solar rooftop program, biofuels and utility-scale solar) and rapidly emerging technologies (e.g., plug-in electric vehicles), and larger-scale investments in a state-of-the-art power system. These larger investments include the Smart Grid and fossil-fuel fleet modernization in the near-to-mid term and new advanced nuclear generation in the longer term.

Financial highlights

Years ended December 31 *(in millions except per share data)*	**2009**	2008	2007
Financial Data			
Operating revenues	**$9,885**	$9,167	$9,153
Net income attributable to controlling interests	**757**	830	504
Income from continuing operations	**840**	778	702
Ongoing earnings per common share*	**3.03**	2.96	2.71
Reported GAAP earnings per common share	**2.71**	3.17	1.96
Average common shares outstanding	**279**	262	257
Common Stock Data			
Return on average common stock equity (percent)	**8.13**	9.59	5.97
Book value per common share	**$33.53**	$32.97	$32.41
Market value per common share (closing)	**$41.01**	$39.85	$48.43

**See page 128 for a reconciliation of ongoing earnings per share to reported GAAP earnings per share.*



A specific example of our strategy is the fleet-modernization announcement we made late last year to retire our 11 oldest coal-fired generating units in the Carolinas – about a third of our coal fleet there. We will replace that nearly 1,500 megawatts of capacity with highly efficient combined-cycle natural-gas turbines and possibly biomass conversion. This has many benefits: a substantial reduction in air emissions (including those linked to climate change), less exposure to issues with coal-ash management, and a positive boost to both local economic development and utility earnings. We believe this is a positive, responsible step no matter what happens with future climate policy.

Complementing our Balanced Solution approach is our Continuous Business Excellence strategy for making internal efficiency and productivity improvements. Unlike short-term belt-tightening, this is a systematic, long-term effort to engage employees in achieving sustainable cost savings and other improvements. We're seeing encouraging early success and expect much more in the years ahead.

In assessing the overall situation Progress Energy faces, I am confident we will meet our short-term priorities while also producing long-term value for our customers and shareholders. In other words, we will manage the present and create the future.

Integrity, transparency and trust

In closing, I want to assure you that acting with integrity remains a core value of this company – behavior that includes not only being honest and ethical in our business practices but also being open in our communications and reliable in doing what we say we will do. We are committed to earning your confidence and trust year after year, in good times and bad – both by what we do and how we do it.

Thank you for your interest in Progress Energy.

William D. Johnson

William D. Johnson
Chairman, President and Chief Executive Officer
March 2010

EXECUTIVE AND SENIOR OFFICERS

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

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

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

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

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

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

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

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

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

Frank A. Schiller
Senior Vice President – Compliance
and General Counsel
Progress Energy, Inc.
Chief Compliance Officer
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

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

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, future liquidity requirements and estimated capital expenditures through the year 2012; and d) "Other Matters" about the effects of new environmental regulations, changes in the regulatory environment, meeting anticipated demand in our regulated service territories, potential nuclear construction and our synthetic fuels tax credits.

Examples of factors that you should consider with respect to any forward-looking statements made throughout this document include, but are not limited to, the following: the impact of fluid and complex laws and regulations, including those relating to the environment and energy policy; our ability to recover eligible costs and earn an adequate return on investment through the regulatory process; the ability to successfully operate electric generating facilities and deliver electricity to customers; the impact on our facilities and businesses from a terrorist attack; the ability to meet the anticipated future need for additional baseload generation and associated transmission facilities in our regulated service territories and the accompanying regulatory and financial risks; our ability to meet current and future renewable energy requirements; the inherent risks associated with the operation and potential construction of nuclear facilities, including environmental, health, regulatory and financial risks; the financial resources and capital needed to comply with environmental laws and regulations; risks associated with climate change; weather and drought conditions that directly influence the production, delivery and demand for electricity; recurring seasonal fluctuations in demand for electricity; the ability to recover in a timely manner, if at all, costs associated with future significant weather events through the regulatory process; fluctuations in the price of energy commodities and purchased power and our ability to recover such costs through the regulatory process; our ability to control costs, including operations and maintenance expense (O&M) and large construction projects; the ability of our subsidiaries to pay upstream dividends or distributions to Progress Energy, Inc. holding company (the Parent); current economic conditions; the ability to successfully access capital markets on favorable terms; the stability of commercial credit markets and our access to short- and long-term credit; the impact that increases in leverage or reductions in cash flow may have on us; our ability to maintain our current credit ratings and the impacts in the event our credit ratings are downgraded; the investment performance of our nuclear decommissioning trust (NDT) funds; the investment performance of the assets of our pension and benefit plans and resulting impact on future funding requirements; the impact of potential goodwill impairments; our ability to fully utilize tax credits generated from the previous production and sale of qualifying synthetic fuels under Internal Revenue Code Section 29/45K (Section 29/45K); and the outcome of any ongoing or future litigation or similar disputes and the impact of any such outcome or related settlements. Many of these risks similarly impact our nonreporting subsidiaries.

These and other risk factors are detailed from time to time in our filings with the SEC. All such factors are difficult to predict, contain uncertainties that may materially affect actual results and may be beyond our control. New factors emerge from time to time, and it is not possible for management to predict all such factors, nor can management assess the effect of each such factor on Progress Energy.

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 (PEC) and Progress Energy Florida (PEF), as the "Utilities." MD&A should be read in conjunction with the Progress Energy Consolidated Financial Statements.

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

Certain amounts for 2008 and 2007 have been reclassified to conform to the 2009 presentation.

INTRODUCTION

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

Strategy

We are an integrated energy company primarily focused on the end-use electricity markets. We own two electric utilities that operate in regulated retail utility markets in North Carolina, South Carolina and Florida and have access to attractive wholesale markets in the eastern United States. The Utilities have more than 22,000 megawatts (MW) of regulated electric generation capacity and serve approximately 3.1 million retail electric customers as well as other load-serving entities. Please review "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

We have a strong track record of meeting our financial commitments and delivering operational excellence. We have maintained liquidity and financial stability and sustained our dividend rate during the current economic downturn, and we believe that we have good prospects for growth once the economy begins to recover. An improving national economy may lead to greater mobility for homeowners around the country and a return of migration to the Southeast region that is more consistent with historical levels. The utility industry, as a whole, however, faces significant cost pressures and, in the near term, lower retail electricity sales. In addition, current economic conditions and anticipated higher expenditures (including for environmental compliance, renewable energy standards compliance and new generation and transmission facilities) may subject us to an even higher level of scrutiny from regulators and lead to a more uncertain regulatory environment. We anticipate the need to prepare for a different kind of energy future – one that would include, among other things, reducing carbon emissions and using emerging technologies such as the Smart Grid and electric vehicles. We believe that our balanced solution strategy provides an effective, flexible framework to prepare for this new energy future. Additional information about the strategy, including updates on implementation, is included in "Strategic Initiatives" below.

To manage the challenges of the present and prepare for the future, management's priority focus areas for 2010 and beyond are as follows:

- Financial Performance
- Operational Performance
- Organizational Effectiveness
- Regulation and Public Policy
- Strategic Initiatives

The first two priorities are core elements of managing our business. The next two priorities will help enable what we can accomplish in the future. The last priority involves making the right investments to create a strong energy future for Progress Energy and our customers.

FINANCIAL AND OPERATIONAL PERFORMANCE

Effectively managing expenses, deploying capital and enhancing our margin are critical to achieving sustainable earnings growth and attractive long-term returns for our shareholders. We have instituted throughout our organization systematic approaches to achieve sustainable cost savings through enhanced efficiency and productivity. These ongoing cost management initiatives – along with short-term expense management – have enabled us to offset some of the impact of the economic downturn and cost pressures and should yield long-term operations and maintenance (O&M) expense savings and effective capital management. Also, we recognize that our shareholders strongly value our dividend and that it is an integral part of our total shareholder return proposition. Our long-term goal is to achieve a 70 to 75 percent dividend payout ratio, and we are committed to managing the company such that we reach this target while maintaining an attractive, sustainable dividend rate.

Our financial performance depends on the successful operation of the Utilities' electric generating and distribution facilities and reliable delivery of electric service to our customers. Consequently, we strive to excel in safety, operational performance and customer satisfaction. We also focus on rigorous project management in executing our capital program, including large-scale capital projects such as construction of new generating facilities, modernization of existing facilities and environmental compliance as well as programs such as demand-side management (DSM).

Another operational priority is a fleet alignment initiative to strengthen the Utilities' nuclear performance in safely and reliably producing electricity while meeting the highest standards of environmental protection in the most efficient manner. The multi-year initiative implements a new business model for our five nuclear units and is based on industry benchmarking that coordinated, collaborative and standardized operations achieve and sustain a higher level of performance than would be possible if each unit operated autonomously. The goals of the initiative are, among other things, to establish a common vision and set of core values; facilitate common procedures across the fleet to accommodate shared resources and industry best practices; and establish a strong performance-monitoring system that provides feedback to management.

ORGANIZATIONAL EFFECTIVENESS

With our managers and supervisors at all levels, we emphasize demonstrating the leadership behaviors that fully engage our workforce and optimize their performance in executing our strategy. We strive to cultivate an inclusive work environment in which we treat everyone with respect and hold each other to high standards. In addition, we are implementing long-term workforce strategies to prepare for our changing needs and an aging workforce. Our workforce strategy includes recruiting, training and retaining a skilled, diverse workforce that reflects the communities we serve.

REGULATION AND PUBLIC POLICY

PEC and PEF are regulated by the state utility commissions in their state jurisdictions. Our regulatory strategy is based on filing reasonable rate requests designed to provide recovery of prudent expenses and a fair return on utility investments. Our business plans include the assumption that the respective public utility commissions will provide reasonable recovery. In 2009, PEC received approval for its coal-to-gas fleet modernization plan discussed in "Strategic Initiatives" as well as multiple DSM, renewable energy and energy-efficiency filings. Also in 2009, PEF successfully sought interim and limited rate relief and nuclear cost recovery in Florida. However, in response to a 2009 base rate case PEF filed with the Florida Public Service Commission (FPSC), in January 2010, the FPSC decided to grant PEF no increase in base rates above what was previously awarded in 2009 for the repowered Bartow Plant (approximately $132 million annual revenue requirements). The FPSC's decision was predicated on its desire to hold down rates. However, we believe the PEF revenue level approved in January 2010 is inadequate given our current costs of providing customers with reliable service, anticipated costs to responsibly prepare for their future energy needs and PEF's right by law to a reasonable opportunity to recover its operating costs and return on invested capital. We are currently reviewing our regulatory options in Florida. We believe that the FPSC's regulatory action was strongly influenced by the current economic downturn. In a long-term view of Florida's regulatory environment, we believe that as the economy improves, the need to provide for Florida's energy future will have a stronger influence in the FPSC's decision-making process. Consequently, we do not believe the January 2010 decision represents a permanent change to the regulatory environment in Florida.

We are subject to significant federal and state regulations regarding air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. Changes in federal and state regulation are currently under consideration for, among others, greenhouse gases (GHG) such as carbon dioxide (CO_2), coal combustion products, mercury and particulate matter. With the state, federal and international focus on global climate change, we are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue. 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. However, we anticipate that it could result in significant rate increases over time to recover the compliance costs.

We are dedicated to seeking achievable, affordable climate and energy policies. We evaluate public policy proposals and actively promote initiatives that are achievable but manage the long-term costs to our customers.

STRATEGIC INITIATIVES

Our balanced solution strategy is intended to deploy capital effectively to meet future customer needs and emerging public policies while achieving our financial objectives. It is a three-pronged strategy that focuses on energy efficiency, alternative energy and state-of-the-art power generation. Expenditures to achieve our balanced solution should be recoverable under base rates or cost-recovery mechanisms implemented by our state jurisdictions. Updates on our implementation of this strategy are discussed below.

First, we are expanding and enhancing our DSM, energy-efficiency and energy conservation programs. We have implemented expanded energy-efficiency programs to our customers and continue to pursue additional initiatives. Federal law enacted in 2009 contains provisions promoting energy efficiency and renewable energy and we have been notified of our selection for Smart Grid grant negotiations.

Second, we are actively engaged in a variety of alternative energy projects. We have executed contracts to purchase approximately 320 MW of electricity generated from solar, biomass and municipal solid waste sources. While this currently represents a small percentage of our total capacity, we will continue to pursue additional contracts for these and other alternative energy sources.

Third, we are evaluating new generation and fleet upgrades to meet the anticipated demand at both PEC and PEF toward the end of the next decade. We are evaluating modernization of existing coal plants and the best new generation options, including advanced design nuclear technology and gas-fired combined cycle and combustion turbines. In 2009, we completed the repowering of PEF's Bartow Plant, construction of a new 157-MW combustion turbine at PEC and the installation of pollution control equipment (or scrubbers) on PEF's coal-fired unit, Crystal River Unit No. 5 (CR5), and PEC's Mayo Plant. We also received approval to construct a 600-MW combined cycle dual-fuel facility and a 950-MW combined cycle natural gas-fueled facility at PEC, which are expected to come online in 2011 and 2013, respectively. PEC has filed for approval to construct a 620-MW natural gas-fueled facility. In 2009, we also announced our intention to embark on a major coal-to-gas fleet modernization in North Carolina by retiring approximately 1,500 MW of older coal-fired units by the end of 2017 and building combined-cycle gas. This will provide rate base growth while reducing our carbon emissions.

While we have not made a final determination on nuclear construction, we have taken steps to keep open the option of building a plant or plants. In 2008, each Utility filed a combined license (COL) application with the Nuclear Regulatory Commission (NRC) for two additional reactors each at Shearon Harris Nuclear Plant (Harris) and at a greenfield site in Levy County, Florida (Levy).

We have focused on Levy given the need for more fuel diversity in Florida and anticipated federal and state policies to reduce GHG emissions, as well as existing state legislative policy that is supportive of nuclear projects. PEF has received two of the three key approvals (with the issuance of a COL remaining) and entered into an engineering, procurement and construction (EPC) agreement for the two proposed Levy units. In light of a regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Later in 2010, PEF will file its annual nuclear cost-recovery filing with the FPSC, which will reflect our latest plan with respect to Levy.

In summary, we are effectively dealing with today's challenges while taking steps to create long-term value for our customers and shareholders.

RESULTS OF OPERATIONS

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

A reconciliation of "Ongoing Earnings" to GAAP net income attributable to controlling interests is below, followed by an explanation of our non-GAAP financial measurement, "Ongoing Earnings."

communications with our board of directors, employees, shareholders, analysts and investors concerning our financial performance. Management believes this non-GAAP measure is appropriate for understanding the business and assessing our potential future performance, because excluded items are limited to those that management believes are not representative of our fundamental core earnings. We compute Ongoing Earnings as GAAP net income attributable to controlling interests after excluding discontinued operations and the effects of certain identified gains and charges. Some

(in millions except per share data)	PEC	PEF	Corporate and Other	Total	Per Share
For the year ended December 31, 2009					
Ongoing Earnings	$540	$460	$(154)	$846	$3.03
CVO mark-to-market	–	–	19	19	0.07
Impairment, net of tax[a]	–	–	(2)	(2)	(0.01)
Plant retirement charge, net of tax[a]	(17)	–	–	(17)	(0.06)
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax[a]	(10)	–	–	(10)	(0.04)
Discontinued operations attributable to controlling interests, net of tax	–	–	(79)	(79)	(0.28)
Net income (loss) attributable to controlling interests[b]	$513	$460	$(216)	$757	$2.71
For the year ended December 31, 2008					
Ongoing Earnings	$531	$383	$(138)	$776	$2.96
Valuation allowance and related net operating loss carry forward	–	–	(3)	(3)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	–	–	57	57	0.22
Net income (loss) attributable to controlling interests[b]	$531	$383	$(84)	$830	$3.17
For the year ended December 31, 2007					
Ongoing Earnings	$498	$315	$(118)	$695	$2.71
CVO mark-to-market	–	–	(2)	(2)	(0.01)
Discontinued operations attributable to controlling interests, net of tax	–	–	(189)	(189)	(0.74)
Net income (loss) attributable to controlling interests[b]	$498	$315	$(309)	$504	$1.96

[a] Calculated using assumed tax rate of 40 percent.
[b] Net income attributable to controlling interests is shown net of preferred stock dividend requirement of $(3) million and $(2) million at PEC and PEF, respectively.

Management uses the non-GAAP financial measure Ongoing Earnings (i) as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends; (ii) as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations; (iii) as a measure for determining levels of incentive compensation; and (iv) in of the excluded gains and charges have occurred in more than one reporting period but are not considered representative of fundamental core earnings. Historically, Ongoing Earnings for our reportable segments, which are PEC and PEF, have been consistent with the most comparable GAAP measure, net income attributable to controlling interests. In 2009, PEC recorded charges that management determined should be excluded from

PEC's Ongoing Earnings. The charges were related to its planned retirement of certain coal-fired generating units prior to the end of their estimated useful lives and a cumulative prior period adjustment related to certain employee life insurance benefits. The prior period adjustment, which was recorded in the fourth quarter of 2009, was not material to previously issued or current period financial statements. Ongoing Earnings is not a measure calculated in accordance with GAAP, and should be viewed as a supplement to, and not a substitute for, our results of operations presented in accordance with GAAP.

Overview

FOR 2009 AS COMPARED TO 2008 AND 2008 AS COMPARED TO 2007

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

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

Partially offsetting these items were:

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

For the year ended December 31, 2008, our net income attributable to controlling interests was $830 million, or $3.17 per share, compared to $504 million, or $1.96 per share, for the same period in 2007. The increase in 2008 as compared to 2007 was due primarily to:

- favorable impact of discontinued non-utility businesses (Ongoing Earnings adjustment);
- favorable allowance for funds used during construction (AFUDC) at the Utilities;
- increased retail base rates at PEF;
- higher wholesale revenues at PEF;
- lower purchased power capacity costs at PEC due to the expiration of a power buyback agreement; and
- favorable net retail customer growth and usage at PEC.

Partially offsetting these items were:

- higher interest expense at PEF;
- higher income tax expense due to the benefit from the closure of certain federal tax years and positions in 2007;
- unfavorable net retail customer growth and usage at PEF;
- unfavorable weather at PEC;
- higher investment losses of certain employee benefit trusts at PEF and Corporate and Other resulting from the decline in market conditions; and
- higher depreciation and amortization expense at PEF excluding prior year recoverable storm amortization at PEF.

Progress Energy Carolinas

PEC contributed net income available to parent totaling $513 million, $531 million and $498 million in 2009, 2008 and 2007, respectively. The decrease in net income available to parent for 2009 as compared to 2008 was primarily due to unfavorable net retail customer growth and usage, coal plant retirement charges, higher base depreciation and amortization expense and a cumulative prior period adjustment related to certain employee life insurance benefits, partially offset by Clean Smokestacks Act amortization and depreciation expense associated with the accelerated cost-recovery program for nuclear generating assets recognized in 2008 and the favorable impact of weather. PEC contributed Ongoing Earnings of $540 million in 2009. There were no Ongoing Earnings adjustments in 2008 and 2007. The 2009 Ongoing Earnings adjustments to net income available to parent were due to PEC recording a $17 million charge, net of tax, for the impact of PEC's decision to retire certain coal-fired generating units prior to the end of their estimated useful lives and recording a $10 million charge, net of tax, for a cumulative prior period adjustment related to certain employee life insurance benefits. Management does not consider these charges to be representative of PEC's fundamental core earnings and excluded these charges in computing PEC's Ongoing Earnings.

The increase in net income available to parent for 2008 as compared to 2007 was primarily due to lower purchased power capacity costs due to the expiration of a power buyback agreement, favorable AFUDC and favorable net retail customer growth and usage, partially offset by the unfavorable impact of weather and lower excess generation revenues.

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

REVENUES

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

(in millions)

Customer Class	2009	% Change	2008	% Change	2007
Residential	**$1,179**	1.6	$1,160	(1.0)	$1,172
Commercial	**741**	(0.9)	748	0.4	745
Industrial	**374**	(10.1)	416	2.0	408
Governmental	**62**	(3.1)	64	4.9	61
Unbilled	**5**	–	8	–	(1)
Total retail base revenues	**2,361**	(1.5)	2,396	0.5	2,385
Wholesale base revenues	**310**	–	310	(12.7)	355
Total Base Revenues	**2,671**	(1.3)	2,706	(1.2)	2,740
Clause-recoverable regulatory returns	**6**	–	–	–	–
Miscellaneous	**114**	11.8	102	5.2	97
Fuel and other pass-through revenues	**1,836**	–	1,621	–	1,548
Total operating revenues	**$4,627**	4.5	$4,429	1.0	$4,385

PEC's total retail base revenues were $2.361 billion and $2.396 billion for 2009 and 2008, respectively. The $35 million decrease in revenues was due primarily to the $58 million unfavorable impact of net retail customer growth and usage, partially offset by the $23 million favorable impact of weather. The unfavorable impact of net retail customer growth and usage was driven by a decrease in the average usage per retail customer, partially offset by a net 14,000 increase in the average number of customers for 2009 compared to 2008. However, PEC's rate of residential growth has declined as PEC's average number of customers increased a net 24,000 customers for 2008 compared to 2007. The favorable impact of weather was driven by higher heating and cooling degree days than 2008 of 3 percent and 5 percent, respectively. Additionally, cooling degree days were 6 percent higher than normal in 2009.

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

PEC's total retail base revenues were $2.396 billion and $2.385 billion for 2008 and 2007, respectively. The $11 million increase in revenues was due primarily to the $34 million favorable impact of net retail customer growth and usage, partially offset by the $28 million unfavorable impact of weather. The favorable net retail customer growth and usage was driven by a net 24,000 increase in the average number of customers for 2008 compared to 2007, partially offset by lower average usage per retail customer. Weather had an unfavorable impact as cooling degree days were 12 percent lower than 2007, even though cooling degree days were comparable to normal.

PEC's wholesale base revenues were $310 million and $355 million for 2008 and 2007, respectively. The $45 million lower wholesale base revenues were driven by $24 million lower excess generation sales due to unfavorable market dynamics due to higher relative fuel costs and $22 million lower revenues related to capacity contracts with two major customers.

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

(in millions of kWh)

Customer Class	2009	% Change	2008	% Change	2007
Residential	**17,117**	0.7	17,000	(1.2)	17,200
Commercial	**13,639**	(2.2)	13,941	(0.6)	14,032
Industrial	**10,368**	(9.0)	11,388	(4.3)	11,901
Governmental	**1,497**	2.1	1,466	1.9	1,438
Unbilled	**360**	–	(8)	–	(55)
Total retail kWh sales	**42,981**	(1.8)	43,787	(1.6)	44,516
Wholesale	**13,966**	(2.5)	14,329	(6.4)	15,309
Total kWh sales	**56,947**	(2.0)	58,116	(2.9)	59,825

The decrease in retail kWh sales in 2009 was primarily due to a decrease in average usage per retail customer. PEC's industrial kWh sales have decreased 9.0 percent from 2008, primarily due to continued reductions in textile manufacturing in the Carolinas as a result of global competition and domestic consolidation as well as a continued downturn in the lumber and building materials segment as a result of declines in construction. Many of the manufacturers in PEC's service territory have been adversely impacted by the economic conditions, and we expect a relatively slow recovery in industrial sales once the economy begins to recover.

Wholesale kWh sales decreased for 2009 primarily due to decreased excess generation sales resulting from unfavorable market dynamics.

Industrial electric energy sales decreased in 2008 compared to 2007, primarily due to downturns in textile manufacturing and lumber and building materials segment as previously discussed.

PEC has experienced a decline in its retail and wholesale kWh sales due to the economic conditions in the United States. We cannot predict how long these conditions may last or the extent to which they may impact revenues. In the future, PEC's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates.

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 applicable portions 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 $1.909 billion for 2009, which represents a $217 million increase compared to 2008. Fuel used in electric generation increased $334 million to $1.680 billion primarily due to $248 million higher deferred fuel expense and the $86 million net impact of higher fuel costs. The increase in deferred fuel expense was primarily due to the implementation of new fuel rates in North Carolina. The higher fuel costs were primarily due to higher coal prices. Purchased power expense decreased $117 million to $229 million compared to prior year. The decrease was primarily due to lower market purchases of $85 million and lower co-generation of $43 million primarily due to lower system requirements.

Fuel and purchased power expenses were $1.692 billion for 2008, which represents a $9 million increase compared to 2007. Purchased power expense increased $44 million to $346 million compared to 2007. The increase was primarily due to increased economical purchases in 2008 of $78 million, partially offset by the $38 million impact from the expiration of a power buyback agreement with North Carolina Eastern Municipal Power Agency (Power Agency). Fuel used in electric generation decreased $35 million to $1.346 billion primarily due to a $116 million decrease in deferred fuel expense, partially offset by increased fuel costs of $81 million. The decrease in deferred fuel expense was primarily driven by a $64 million impact from the implementation of state legislation that expanded the definition of the traditional fuel clause to include costs of commodities such as ammonia and limestone used in emissions control technologies (reagents), transmission charges and non-capacity-related costs of purchases and a $49 million impact related to under-recovered fuel costs. Deferred fuel expense was higher in 2007 primarily due to the collection of fuel costs from customers that had been previously under-recovered. The increase in fuel costs of $81 million was primarily due to an increase in coal prices, partially offset by the impacts of lower system requirements and a change in the generation mix.

Operation and Maintenance

O&M expense was $1.072 billion for 2009, which represents a $42 million increase compared to 2008. This increase was primarily due to coal plant retirement charges of $28 million, higher pension and benefit costs of $12 million and storm costs of $9 million, partially offset by lower emission allowance expense of $13 million resulting from lower system requirements, changes in generation mix and sales of nitrogen oxide (NOx) allowances. PEC recognized coal plant retirement charges ($17 million, net of tax) for the impact of the decision to retire 11 coal-fired units prior to the end of their estimated useful lives (See "Future Liquidity and Capital Resources – PEC Other Matters" and "Other Matters – Energy Demand"). Management determined that such charges should be an exclusion from PEC's Ongoing Earnings.

O&M expense was $1.030 billion for 2008, which represents a $6 million increase compared to 2007. This increase was driven primarily by a $33 million increase in nuclear expenses, of which $18 million relates to refurbishments, preventive maintenance and incremental outage expenses at Brunswick Nuclear Plant (Brunswick). Additionally, O&M increased due to a $7 million increase in estimated environmental remediation expenses (See Note 21A), partially offset by $19 million lower employee benefits and $16 million lower nuclear plant outage and maintenance costs. The decrease in employee benefits was primarily due to the 2007 impact from changes in stock-based compensation plans and higher relative employee incentive goal achievement. The decrease in nuclear plant outage and maintenance costs was primarily due to two nuclear refueling and maintenance outages in 2008 compared to three in 2007.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $470 million for 2009, which represents a $48 million decrease compared to 2008. This decrease was primarily attributable to the $52 million of depreciation associated with the accelerated cost-recovery program for nuclear generating assets recognized during 2008 (See Note 7B) and the $15 million of Clean Smokestacks Act amortization recognized in 2008, partially offset by the $21 million impact of depreciable asset base increases. The North Carolina jurisdictional aggregate minimum amount of accelerated cost recovery has been met, and the South Carolina jurisdictional obligation was terminated by the Public Service Commission of South Carolina (SCPSC). PEC does not anticipate recording additional accelerated depreciation in the North Carolina jurisdiction, but will record depreciation over the remaining useful lives of the assets. In accordance with a regulatory order, PEC ceased to amortize Clean Smokestacks Act compliance costs, but will record depreciation over the useful lives of the assets (See Note 7B).

Depreciation, amortization and accretion expense was $518 million for 2008, which represents a $1 million decrease compared to 2007. This decrease was primarily attributable to $19 million lower Clean Smokestacks Act amortization, $8 million lower GridSouth Transco, LLC (GridSouth) amortization and $3 million lower storm deferral amortization, partially offset by $15 million higher depreciation associated with the accelerated cost-recovery program for nuclear generating assets and the $15 million impact of depreciable asset base increases.

Taxes Other Than on Income

Taxes other than on income was $210 million, $198 million and $192 million in 2009, 2008 and 2007, respectively. The $12 million increase in 2009 compared to 2008 was primarily due to an increase in gross receipts taxes due to higher operating revenues and higher property tax rates. Gross receipts taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Total Other Income, Net

Total other income, net was $20 million for 2009, which represents a $23 million decrease compared to 2008. This decrease was primarily due to a cumulative prior period adjustment related to certain employee life insurance benefits and lower interest income resulting from lower average eligible deferred fuel balances. During the fourth quarter of 2009, PEC recorded a cumulative prior period adjustment related to certain employee life insurance benefits. The impact of this adjustment decreased total other income, net by $16 million and decreased net income available to parent by $10 million. The prior period adjustment is not material to previously issued or current period financial statements. Management determined that the adjustment should be an exclusion from PEC's Ongoing Earnings.

Total other income, net was $43 million for 2008, which represents a $6 million increase compared to 2007. This increase was primarily due to $17 million favorable AFUDC equity related to eligibility of certain Clean Smokestacks Act compliance costs and other increased eligible construction project costs, partially offset by $9 million lower interest income resulting from lower average eligible deferred fuel balances and lower temporary investment balances.

Total Interest Charges, Net

Total interest charges, net was $195 million for 2009, which represents a $12 million decrease compared to 2008. This decrease was primarily due to lower interest rates on variable rate debt, partially offset by higher interest as a result of higher average debt outstanding.

Total interest charges, net was $207 million for 2008, which represents a $3 million decrease compared to 2007. This decrease was primarily due to the $7 million favorable AFUDC debt related to eligibility of certain Clean Smokestacks Act compliance costs and other increased eligible construction project costs and the $4 million impact of a decrease in average long-term debt, offset by an $11 million interest benefit resulting from the resolution of tax matters in 2007.

Income Tax Expense

Income tax expense was $277 million, $298 million and $295 million in 2009, 2008 and 2007, respectively. The $21 million income tax expense decrease in 2009 compared to 2008 was primarily due to the impact of lower pre-tax income and the $5 million favorable tax benefit related to a deduction triggered by the transfer of previously funded amounts from nonqualified nuclear decommissioning trusts (NDTs) to qualified NDTs. The $3 million income tax expense increase in 2008 compared to 2007 was primarily due to the $14 million impact of higher pre-tax income and the $5 million impact related to the deduction for domestic production activities, partially offset by the $7 million tax impact of employee stock-based benefits and the $7 million impact of the increase in AFUDC equity previously discussed. AFUDC equity is excluded from the calculation of income tax expense.

Progress Energy Florida

PEF contributed net income available to parent and Ongoing Earnings totaling $460 million, $383 million and $315 million in 2009, 2008 and 2007, respectively. The increase in net income available to parent for 2009 as compared to 2008 was primarily due to the higher net impact of returns earned on higher levels of nuclear and ECRC assets to be recovered through respective cost-recovery clauses, the favorable impact of interim and limited base rate relief (See Note 7C) and the favorable impact of weather, partially offset by the unfavorable impact of retail customer growth and usage, higher base depreciation and amortization expense, and higher O&M.

The increase in net income available to parent for 2008 as compared to 2007 was primarily due to favorable AFUDC, increased retail base rates and higher wholesale revenues, partially offset by higher interest expense, unfavorable net retail customer growth and usage, higher depreciation and amortization expense excluding recoverable storm amortization, and higher investment losses of certain employee benefit trusts.

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

REVENUES

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

(in millions)

Customer Class	2009	% Change	2008	% Change	2007
Residential	$946	5.9	$893	3.4	$864
Commercial	340	3.7	328	6.8	307
Industrial	72	(5.3)	76	5.6	72
Governmental	87	6.1	82	5.1	78
Unbilled	9	–	(1)	–	1
Total retail base revenues	1,454	5.5	1,378	4.2	1,322
Wholesale base revenues	207	5.1	197	33.1	148
Total Base Revenues	1,661	5.5	1,575	7.1	1,470
Clause-recoverable regulatory returns	87	690.9	11	450.0	2
Miscellaneous	189	6.2	178	4.7	170
Fuel and other pass-through revenues	3,314	–	2,967	–	3,107
Total operating revenues	$5,251	11.0	$4,731	(0.4)	$4,749

PEF's total retail base revenues were $1.454 billion and $1.378 billion for 2009 and 2008, respectively. The $76 million increase was primarily due to the $79 million favorable impact of interim and limited base rate relief and the $36 million favorable impact of weather, partially offset by the $41 million unfavorable impact of retail customer growth and usage. The interim and limited base rate relief was approved by the FPSC effective July 1, 2009, as discussed in Note 7C. Of the $79 million interim and limited base rate relief, $7 million related to interim rate relief, which was in effect for only 2009, and $72 million related to limited rate relief, which will continue in accordance with the base rate proceeding with an annual revenue requirement of $132 million. The favorable impact of weather was primarily driven by 14 percent higher heating degree days than 2008 and 6 percent higher cooling degree days than 2008. Heating degree days were 4 percent lower than normal in 2009 and 16 percent lower than normal in 2008. In addition to lower average usage per customer, PEF's average number of customers for 2009, compared to 2008, decreased a net 8,000 customers and had no change in customers for 2008, compared to 2007.

PEF's clause-recoverable regulatory returns were $87 million and $11 million for 2009 and 2008, respectively. The $76 million higher revenues related to nuclear cost recovery and ECRC assets of $61 million and $15 million, respectively. As a result of an FPSC regulatory order effective in January 2009, PEF is allowed to earn returns on certain costs related to nuclear construction, as discussed in Note 7C. We anticipate higher returns on ECRC assets in 2010 due to placing approximately $790 million of Clean Air Interstate Rule (CAIR) projects into service in late 2009. However, we do not anticipate a significant change in returns on nuclear cost-recovery assets in 2010 related to Levy.

PEF's total retail base revenues were $1.378 billion and $1.322 billion for 2008 and 2007, respectively. The $56 million increase was primarily due to $90 million of base rate increases, partially offset by the $32 million impact of unfavorable net retail customer growth and usage. The increase in base rates was due to $53 million from Hines 4 being placed in service and the $37 million transfer of Hines 2 cost recovery from the fuel clause to base rates. These base rate changes occurred in accordance with PEF's 2005 base rate settlement agreement.

PEF's wholesale base revenues of $197 million and $148 million for 2008 and 2007, respectively, increased $49 million. The increase was primarily due to several new and amended contracts.

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

(in millions of kWh)

Customer Class	2009	% Change	2008	% Change	2007
Residential	19,399	0.4	19,328	(2.9)	19,912
Commercial	11,884	(2.1)	12,139	(0.4)	12,183
Industrial	3,285	(13.2)	3,786	(0.9)	3,820
Governmental	3,256	(1.4)	3,302	(1.9)	3,367
Unbilled	131	–	(99)	–	(6)
Total retail kWh sales	37,955	(1.3)	38,456	(2.1)	39,276
Wholesale	3,835	(43.1)	6,734	11.8	6,024
Total kWh sales	41,790	(7.5)	45,190	(0.2)	45,300

Wholesale base revenues increased in 2009, despite decreased wholesale kWh sales in 2009, primarily due to committed capacity revenues. The wholesale kWh sales decreased primarily due to market conditions in which wholesale customers fulfilled a portion of their system requirements from other sources. Many of the new and amended capacity contracts entered into in 2008 expired by the end of 2009. Given the current economic conditions discussed below, PEF does not believe it is likely to replace these wholesale contracts in 2010.

Retail base revenues increased in 2009, despite a decrease in kWh sales for the same period, primarily due to the impact of interim and limited base rate relief approved by the FPSC in 2009 (See Note 7C). Retail base revenues increased in 2008, despite a decrease in kWh sales for the same period, primarily due to an increase in base rates in accordance with PEF's 2005 base rate settlement agreement, as previously discussed.

The economic conditions and general housing downturn in the United States has continued to contribute to a slowdown in customer growth and usage in PEF's service territory resulting in a 1.3 percent decrease in retail kWh sales for 2009, compared to 2008, and a 2.1 percent decrease for 2008, compared to 2007. The impact of the general housing downturn was especially severe in several states, including Florida. Additionally, we believe the current economic conditions have impacted our wholesale customers' usage. We cannot predict how long these economic conditions may last or the extent to which revenues may be impacted. In the future, PEF's customer usage could be impacted by customer response to energy-efficiency programs and to increased rates.

EXPENSES

Fuel and Purchased Power

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

Fuel and purchased power expenses were $2.754 billion in 2009, which represents a $126 million increase compared to 2008. Fuel used in electric generation increased $397 million to $2.072 billion compared to 2008. This increase was primarily due to higher deferred fuel expense of $467 million driven by the implementation of new fuel rates, partially offset by decreased current year fuel costs of $70 million. The decrease in current year fuel costs was primarily due to lower system requirements. Purchased power expense decreased $271 million compared to the same period in 2008, primarily due to $164 million lower interchange costs and a decrease in the recovery of deferred capacity costs of $91 million, both resulting from lower system requirements.

Fuel and purchased power expenses were $2.628 billion in 2008, which represents an $18 million decrease compared to 2007. Fuel used in electric generation decreased $89 million to $1.675 billion primarily due to a $381 million decrease in deferred fuel expense, partially offset by increased fuel costs of $293 million. The decrease in deferred fuel expense was primarily due to the regulatory approval to lower the fuel factor for customers effective January 2008 as a result of over-recovery of fuel costs in the prior year. With the increase in fuel prices experienced in 2008, PEF successfully sought a mid-course fuel correction, but the revised fuel factors were not effective until August 2008. The increase in fuel costs was primarily due to increased fuel prices and a change in generation mix. Purchased power expense increased $71 million to $953 million compared to 2007. This increase was primarily due to increased purchases of $37 million as a result of higher fuel costs and an increase in the recovery of deferred capacity costs of $34 million.

Operation and Maintenance

O&M expense was $839 million in 2009, which represents a $26 million increase compared to 2008. The increase was primarily due to $63 million higher ECRC and energy conservation cost recovery clause (ECCR) costs primarily due to an increase in current year rates for recovery of emission allowances, higher pension costs of $24 million and higher nuclear plant outage and maintenance costs of $14 million, partially offset by lower storm cost recovery of $66 million due to the surcharge that ended in July 2008 and the impact of a change in our earned vacation policy of $11 million. The ECRC and ECCR expenses and replenishment of storm damage reserve are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. Pension costs are higher due to a $20 million pension credit in the prior year. Substantially all of 2009's pension expense has been deferred in accordance with an FPSC order (See Note 7C). In the aggregate, O&M expenses recoverable through base rates increased $25 million compared to the same period in 2008.

O&M expense was $813 million in 2008, which represents a $21 million decrease compared to 2007. The decrease was primarily due to $24 million lower ECRC costs due to a decrease in the rates resulting from over-recovery, $12 million lower employee benefit costs primarily due to the 2007 impact from changes in stock-based compensation plans and $12 million lower sales and use tax audit adjustment, partially offset by $19 million related to storm damage reserves replenishment surcharge in effect August 2007 through July 2008 in accordance with a regulatory order, and $11 million higher plant outage and maintenance costs. The ECRC and replenishment of storm damage reserves expenses are recovered through cost-recovery clauses and, therefore, have no material impact on earnings. In the aggregate, O&M expenses recoverable through base rates decreased $19 million compared to the same period in 2007.

Depreciation, Amortization and Accretion

Depreciation, amortization and accretion expense was $502 million for 2009, which represented an increase of $196 million compared to 2008, primarily due to higher nuclear cost-recovery amortization of $155 million (See Note 7C). In aggregate, depreciation, amortization and accretion expenses recoverable through base rates increased $31 million compared to 2008, primarily due to depreciable asset base increases.

Depreciation, amortization and accretion expense was $306 million for 2008, which represented a decrease of $60 million compared to 2007, primarily due to $75 million lower amortization of unrecovered storm restoration costs and a $7 million write-off in 2007 of leasehold improvements primarily related to vacated office space, partially offset by the $20 million impact of depreciable asset base increases. Storm restoration costs, which were fully amortized in August 2007, were recovered through a storm-recovery surcharge and, therefore, had no material impact on earnings (See Note 7C). In aggregate, depreciation, amortization and accretion expenses recoverable through base rates increased $13 million compared to 2007, primarily due to depreciable asset base increases.

Taxes Other Than on Income

Taxes other than on income was $347 million, $309 million and $309 million in 2009, 2008 and 2007, respectively. The $38 million increase in 2009 compared to 2008 was primarily due to an increase in gross receipts and franchise taxes due to higher operating revenues. Gross receipts and franchise taxes are collected from customers and recorded as revenues and then remitted to the applicable taxing authority. Therefore, these taxes have no material impact on earnings.

Other

Other operating expense was an expense of $7 million in 2009, income of $5 million in 2008 and an expense of $8 million in 2007. The $7 million expense in 2009 and the $8 million expense in 2007 were primarily due to regulatory disallowances of fuel costs (See Note 7C). The $5 million income in 2008 was primarily due to gain on land sales.

Total Other Income, Net

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

Total other income, net was $94 million for 2008, which represents a $46 million increase compared to 2007. This increase was primarily due to $54 million favorable AFUDC equity related to eligible construction project costs, partially offset by $11 million of investment losses of certain employee benefit trusts resulting from the decline in market conditions.

Total Interest Charges, Net

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

Total interest charges, net was $208 million in 2008, which represents an increase of $35 million compared to 2007. The increase in interest charges was primarily due to the $60 million impact of an increase in average long-term debt, partially offset by $16 million favorable AFUDC debt related to costs associated with eligible construction projects and $7 million interest benefit resulting from the resolution of tax matters in 2008.

Income Tax Expense

Income tax expense was $209 million, $181 million and $144 million in 2009, 2008 and 2007, respectively. The $28 million income tax expense increase in 2009 compared to 2008 was primarily due to the $40 million impact of higher pre-tax income compared to the prior year, partially offset by the $11 million impact of the favorable tax benefit related to a deduction triggered by the transfer of previously funded amounts from the nonqualified NDT fund to the qualified NDT fund. The $37 million income tax expense increase in 2008 compared to 2007 was primarily due to the $40 million impact of higher pre-tax income compared to 2007, $6 million benefit related to the closure of certain federal tax years and positions in 2007, $4 million due to the accelerated amortization of tax-related regulatory assets in accordance with PEF's 2005 base rate settlement agreement, and $3 million related to the deduction for domestic production activities, partially offset by the $21 million impact of favorable AFUDC equity discussed above. AFUDC equity is excluded from the calculation of income tax expense.

Corporate and Other

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

(in millions)	2009	Change	2008	Change	2007
Other interest expense	$(253)	$(30)	$(223)	$(18)	$(205)
Other income tax benefit	87	1	86	(19)	105
Other income (expense)	12	13	(1)	17	(18)
Ongoing Earnings	(154)	(16)	(138)	(20)	(118)
CVO mark-to-market	19	19	–	2	(2)
Valuation allowance and related net operating loss carry forward	–	3	(3)	(3)	–
Impairment[a]	(2)	(2)	–	–	–
Discontinued operations attributable to controlling interests, net of tax	(79)	(136)	57	246	(189)
Net loss attributable to controlling interests	(216)	(132)	(84)	225	(309)

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

OTHER INTEREST EXPENSE

Other interest expense was $253 million, $223 million and $205 million for 2009, 2008 and 2007, respectively. The $30 million increase for 2009 compared to 2008 was primarily due to higher average debt outstanding at the Parent. The $18 million increase for 2008 compared to 2007 was primarily due to a $6 million 2007 benefit related to the closure of certain federal tax years and positions and a decrease in the interest allocated to discontinued operations. The decrease in interest allocated to discontinued operations resulted from the allocations of interest expense in early 2007 to operations that were sold later in 2007. An immaterial amount and $13 million of interest expense were allocated to discontinued operations for 2008 and 2007, respectively. No interest expense was allocated to discontinued operations in 2009.

OTHER INCOME TAX BENEFIT

Other income tax benefit was $87 million, $86 million and $105 million for 2009, 2008 and 2007, respectively. The $1 million increase for 2009 compared to 2008 was primarily due to higher pre-tax expenses, partially offset by the unfavorable impact at the Corporate level resulting from the deductions taken by the Utilities related to NDT funds (See "Progress Energy Carolinas – Income Tax Expense" and "Progress Energy Florida – Income Tax Expense"). The $19 million decrease for 2008 compared to 2007 was primarily due to the 2007 benefit related to the closure of certain federal tax years and positions.

OTHER INCOME (EXPENSE)

Other income (expense) was $12 million income, $1 million expense and $18 million expense for 2009, 2008 and 2007, respectively. The $13 million change for 2009 compared to 2008 was primarily due to investment gains on certain employee benefit trusts resulting from improved financial market conditions. The $17 million change for 2008 compared to 2007 was primarily due to $15 million decreased indirect corporate overhead due to divestitures completed in 2007 and $12 million decreased legal expenses, partially offset by $8 million of investment losses of certain employee benefit trusts resulting from the decline in market conditions.

CVO MARK-TO-MARKET

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 (See Note 15). The CVOs had a fair value of $15 million at December 31, 2009, and $34 million at December 31, 2008 and 2007. Progress Energy recorded unrealized gains of $19 million for 2009 and unrealized losses of $2 million for 2007, to record the changes in fair value of the CVOs, which had average unit prices of $0.16 at December 31, 2009 and $0.35 at December 31, 2008 and 2007.

VALUATION ALLOWANCE AND RELATED NET OPERATING LOSS CARRY FORWARD

We previously recorded a deferred tax asset for a state net operating loss carry forward upon the sale of Progress Energy Ventures, Inc.'s (PVI) nonregulated generation facilities and energy marketing and trading operations. In 2008, we recorded an additional $6 million deferred tax asset related to the state net operating loss carry forward due to a change in estimate based on 2007 tax return filings. We also evaluated the total state net operating loss carry forward and recorded a partial valuation allowance of $9 million, which more than offset the change in estimate.

IMPAIRMENT

In 2009, Progress Energy recorded impairments of certain investments of our Affordable Housing portfolio.

DISCONTINUED OPERATIONS ATTRIBUTABLE TO CONTROLLING INTERESTS, NET OF TAX

We completed our business strategy of divesting of nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. See Note 3 for additional information related to discontinued operations.

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

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

In 2007, we recognized $189 million of expense from discontinued operations attributable to controlling interests, net of tax, which was comprised primarily of $283 million net losses related to the exit of the Competitive Commercial Operations (CCO) business, partially offset by $83 million net earnings related to the Terminals and Synthetic Fuels businesses. The net losses from the CCO business were primarily due to the $349 million after-tax charge associated with exit costs, partially offset by unrealized mark-to-market gains related to de-designated natural gas hedges. We had substantial operations associated with the production of coal-based solid synthetic fuels. The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Impact of Utility Regulation

Our regulated utilities segments are subject to regulation that sets the prices (rates) we are permitted to charge customers based on the costs that regulatory agencies determine we are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by a nonregulated company. The application of GAAP for regulated operations to this ratemaking process results in deferral of expense recognition and the recording of regulatory assets based on anticipated future cash inflows. As a result of the different ratemaking processes in each state in which we operate, a significant amount of regulatory assets has been recorded. We continually review these regulatory assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future. Additionally, the state regulatory agencies' ratemaking processes often provide flexibility in the manner and timing of the depreciation of property, nuclear decommissioning costs and amortization of the regulatory assets.

Our conclusion that we meet the criteria to apply GAAP for regulated operations is a material assumption in the presentation and evaluation of our and the Utilities' financial position and results of operations. The Utilities' ability to continue to meet the criteria for application of GAAP for regulated operations could be affected in the future by actions of our regulators, competitive forces and restructuring in the electric utility industry. State regulators may not allow the Utilities to increase future retail rates required to recover their operating costs or provide an adequate return on investment, or in the manner requested. State regulators may also seek to reduce or freeze retail rates. Such events occurring over a sustained period could result in the Utilities no longer meeting the criteria for the continued application of GAAP for regulated operations. In the event that GAAP for regulated operations no longer applies to one or both of the Utilities, we are subject to the risk that regulatory assets and liabilities would be eliminated and utility plant assets may be impaired, unless an appropriate recovery mechanism was provided. Additionally, our financial condition, cash flows and results of operations may be adversely impacted. See Note 7 for additional information related to the impact of utility regulation on our operations.

We evaluate the carrying value of long-lived assets and intangible assets with definite lives for impairment whenever impairment indicators exist. If an impairment indicator exists, the asset group held and used is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or if the asset group is to be disposed of, an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group. Our exposure to potential impairment losses for utility plant, net is mitigated by the fact that our regulated ratemaking process generally allows for recovery of our investment in utility plant plus an allowed return on the investment, as long as the costs are prudently incurred. The carrying value of our total utility plant, net at December 31, 2009 and 2008, was $19.733 billion and $18.293 billion, respectively.

As discussed in Note 13, our financial assets and liabilities are primarily comprised of derivative financial instruments and marketable debt and equity securities held in our nuclear decommissioning trusts. Substantially all unrealized gains and losses on derivatives and all unrealized gains and losses on nuclear decommissioning trust investments are deferred as regulatory liabilities or assets consistent with ratemaking treatment. Therefore, the impact of fair value measurements from recurring financial assets and liabilities on our earnings is not significant.

Asset Retirement Obligations

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

AROs have no impact on our income as the effects are offset by the establishment of regulatory assets and regulatory liabilities.

Our total AROs at December 31, 2009, were $1.170 billion. We calculated the present value of our AROs based on estimates which are dependent on subjective factors such as management's estimated retirement costs, the timing of future cash flows and the selection of appropriate discount and cost escalation rates. These underlying assumptions and estimates are made as of a point in time and are subject to change. These changes could materially affect the AROs, although changes in such estimates should not affect earnings, because these costs are expected to be recovered through rates.

Nuclear decommissioning AROs represent 95 percent of Progress Energy's total AROs at December 31, 2009. To determine nuclear decommissioning AROs, we utilize periodic site-specific cost studies in order to estimate the nature, cost and timing of planned decommissioning activities for our nuclear plants. Our regulators require updated cost estimates for nuclear decommissioning every five years. These cost studies are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. Changes in PEC's and PEF's nuclear decommissioning site-specific cost estimates or the use of alternative cost escalation or discount rates could be material to the nuclear decommissioning liabilities recognized.

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

PEF obtained an updated cost study for its nuclear plant in 2008, using 2008 cost factors. If the site-specific cost estimates increased by 10 percent, PEF's AROs would have increased by $32 million. If the inflation adjustment increased 25 basis points, PEF's AROs would have increased by $25 million. Similarly, an increase in the discount rate of 25 basis points would have decreased PEF's AROs by $23 million.

Goodwill

As discussed in Note 8, goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments and our goodwill impairment tests are performed at the utility segment level. The carrying amounts of goodwill at December 31, 2009 and 2008, for reportable segments PEC and PEF, were $1.922 billion and $1.733 billion, respectively. We perform our annual impairment tests as of April 1 each year. During the second quarter of 2009, we completed the 2009 annual tests, which indicated the goodwill was not impaired. If the fair value of PEC had been lower by 10 percent and the fair value of PEF had been lower by 7.5 percent, there still would be no impact on the reported value of their goodwill.

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

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

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

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

As an overall test of the reasonableness of the estimated fair values of the utility segments, we compared their combined fair value estimate to Progress Energy's market capitalization as of April 1, 2009. The analysis confirmed that the fair values were reasonably representative of market views when applying a reasonable control premium to the market capitalization.

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

Unbilled Revenue

As discussed in Note 1, we recognize electric utility revenues as service is rendered to customers. Operating revenues included unbilled electric utilities base revenues earned when service has been delivered but not billed by the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis through the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for the electric utility revenues associated with unbilled sales is recognized. Unbilled revenues are estimated by applying a weighted average revenue/kWh for all customer classes to the number of estimated kWh delivered but not billed. The calculation of unbilled revenue is affected by factors that include fluctuations in energy demand for the unbilled period, seasonality, weather, customer usage patterns, price in effect for each customer class and estimated transmission and distribution line losses. At December 31, 2009 and 2008, amounts recorded as receivables on the Consolidated Balance Sheets related to unbilled revenues were $193 million and $182 million, respectively.

Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. As discussed in Note 14, deferred income tax assets and liabilities represent the future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The probability of realizing deferred tax assets is based on forecasts of future taxable income and the availability of tax-planning strategies that can be implemented, if necessary, to realize deferred tax assets. We establish a valuation allowance when it is more likely than not that all, or a portion of, a deferred tax asset will not be realized.

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

Pension Costs

As discussed in Note 16A, we maintain qualified noncontributory defined benefit retirement (pension) plans. We also have supplementary defined benefit pension plans that provide benefits to higher-level employees. Our reported costs are dependent on numerous factors resulting from actual plan experience and assumptions of future experience. For example, such costs are impacted by employee demographics, changes made to plan provisions, actual plan asset returns and key actuarial assumptions, such as expected long-term rates of return on plan assets and discount rates used in determining benefit obligations and annual costs.

Due to a slight decrease in the market interest rates for high-quality (AAA/AA) debt securities, which are used as the benchmark for setting the discount rate to calculate the present value of future benefit payments, we decreased the discount rate to 6.00% at December 31, 2009, from 6.30% at December 31, 2008, which will increase 2010 pension costs, all other factors remaining constant. Our discount rates are selected based on a plan-by-plan study, which matches our projected benefit payments to a high-quality corporate yield curve. Consistent with general market conditions, our plan assets performed well in 2009 with returns of approximately 23%. That positive asset performance will result in decreased pension costs in 2010, all other factors remaining constant. In addition, contributions to pension plan assets in late 2009 and 2010 will result in decreased pension costs in 2010 due to increased asset balances, all other factors remaining constant. Evaluations of the effects of these and other factors on our 2010 pension costs have not been completed, but we estimate that the total cost recognized for pensions in 2010 will be $80 million to $90 million, compared with $107 million (before the $34 million deferral; see Notes 7C and 16A) recognized in 2009.

We have pension plan assets with a fair value of approximately $1.7 billion at December 31, 2009. Our expected rate of return on pension plan assets is 8.75%. The expected rate of return used in pension cost recognition is a long-term rate of return; therefore, we do not adjust that rate of return frequently. In 2009, we lowered the expected rate of return from the previously used 9.00%, due primarily to the uncertainties resulting from the severe capital market deterioration in 2008. A 25 basis point change in the expected rate of return for 2009 would have changed 2009 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 8.75% expected long-term rate of return is applied. Entities may use either fair value or an averaging method that recognizes changes in fair value over a period not to exceed five years, with the method selected applied on a consistent basis from year to year. We have historically used a five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets. Changes in plan asset performance are reflected in pension costs sooner under the fair value method than the five-year averaging method, and, therefore, pension costs tend to be more volatile using the fair value method. Approximately 50 percent of our pension plan assets are subject to each of the two methods.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our significant cash requirements arise primarily from the capital-intensive nature of the Utilities' operations, including expenditures for environmental compliance. We rely upon our operating cash flow, substantially all of which is 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. As discussed in "Future Liquidity and Capital Resources" below, synthetic fuels tax credits provide an additional source of liquidity as those credits are realized.

The majority of our operating costs are related to the Utilities. Most of these costs are recovered from ratepayers in accordance with various rate plans. We are allowed to recover certain fuel, purchased power and other costs incurred by PEC and PEF through their respective recovery clauses. The types of costs recovered through clauses vary by jurisdiction. Fuel price volatility 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.

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

The Parent is a holding company and, as such, has no revenue-generating operations of its own. The primary cash needs at the Parent level are our common stock dividend, interest and principal payments on the Parent's $4.3 billion of senior unsecured debt and potentially funding the Utilities' capital expenditures through equity contributions. The Parent's ability to meet these needs is typically funded with dividends from the Utilities generated from their earnings and cash flows, and to a lesser extent, dividends from other subsidiaries; repayment of funds due to the Parent by its subsidiaries; the Parent's bank facility; and/or the Parent's ability to access the short-term and long-term debt and equity capital markets. In recent years, rather than paying dividends to the Parent, the Utilities, to a large extent, have retained their free cash flow to fund their capital expenditures. During 2009, PEC paid a dividend of $200 million to the Parent and PEF received equity contributions of $620 million from the Parent. PEC and PEF expect to pay dividends to the Parent in 2010. There are a number of factors that impact the Utilities' decision or ability to pay dividends to the Parent or to seek equity contributions from the Parent, including capital expenditure decisions and the timing of recovery of fuel and other pass-through costs. Therefore, we cannot predict the level of dividends or equity contributions between the Utilities and the Parent from year to year. The Parent could change its existing common stock dividend policy based upon these and other business factors.

Cash from operations, commercial paper issuance, borrowings under our credit facilities, long-term debt financings, and/or limited ongoing sales of common stock from our Progress Energy Investor Plus Plan (IPP), employee benefit and stock option plans are expected to fund capital expenditures, long-term debt maturities and common stock dividends for 2010. For the fiscal year 2010, we plan, subject to market conditions, to realize up to $500 million from the sale of stock through ongoing equity sales. As discussed further in "Credit Rating Matters," our ability to access the capital markets on favorable terms may be negatively impacted by recent, and potentially future, rating actions.

We have 16 financial institutions that support our combined $2.030 billion revolving credit facilities for the Parent, PEC and PEF, thereby limiting our dependence on any one institution. The credit facilities serve as backups to our commercial paper programs. To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009, the Parent had no outstanding borrowings under its credit facility, an outstanding commercial paper balance of $140 million and had issued $37 million of letters of credit, which were supported by the revolving credit facility. At December 31, 2009, PEC and PEF had no outstanding commercial paper. Based on these outstanding amounts at December 31, 2009, there was $1.853 billion available for additional borrowings. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper with proceeds from the $950 million November 2009 issuance of Senior Notes.

Borrowings under our revolving credit agreement (RCA) during 2008, which were repaid during 2009, coupled with commercial paper, long-term debt and equity issuances in 2009, provided liquidity during a period of uncertain financial market conditions. We will continue to monitor the credit markets to maintain an appropriate level of liquidity.

At December 31, 2009, PEC and PEF had limited counterparty mark-to-market exposure for financial commodity hedges (primarily gas and oil hedges) due to spreading our concentration risk over a number of counterparties. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2009, the majority of the Utilities' open financial commodity hedges were in net mark-to-market liability positions. See Note 17A for additional information with regard to our commodity derivatives.

At December 31, 2009, we had limited mark-to-market exposure to certain financial institutions under pay-fixed forward starting swaps to hedge cash flow risk with regard to future financing transactions for the Parent, PEC and PEF. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates. At December 31, 2009, each sum of the Parent's, PEC's and PEF's open pay-fixed forward starting swaps was in a net mark-to-market asset position. See Note 17B for additional information with regard to our interest rate derivatives.

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

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

Historical for 2009 as Compared to 2008 and 2008 as Compared to 2007

CASH FLOWS FROM OPERATIONS

Net cash provided by operations is the primary source used to meet operating requirements and a portion of capital expenditures. The Utilities produced substantially all of our consolidated cash from operations for the years ended December 31, 2009, 2008 and 2007. Net cash provided by operating activities for the three years ended December 31, 2009, 2008 and 2007, was $2.271 billion, $1.218 billion and $1.252 billion, respectively.

Net cash provided by operating activities for 2009 increased when compared with 2008. The $1.053 billion increase in operating cash flow was primarily due to a $623 million increase in the recovery of deferred fuel costs due to higher fuel rates and $340 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $200 million net refunds of cash collateral in 2009. These impacts were partially offset by $221 million of pension and other benefits contributions made in 2009.

Net cash provided by operating activities for 2008 decreased when compared with 2007. The $34 million decrease in operating cash flow was primarily due to a $450 million decrease in the recovery of fuel costs due to the 2008 under-recovery driven by rising fuel costs, compared to an over-recovery of fuel costs during the corresponding period in 2007; $340 million of cash collateral paid to counterparties on derivative contracts in 2008 compared to $55 million in net refunds of cash collateral in 2007, primarily at PEF; and a $226 million increase in inventory purchases, primarily coal, driven by higher prices. These impacts were partially offset by a $419 million increase from accounts receivable, primarily related to our divested CCO operations and former synthetic fuels businesses; the $347 million payment made in 2007 to exit the contract portfolio consisting of full-requirements contracts with 16 Georgia electric membership cooperatives formerly serviced by CCO (the Georgia contracts) (See Note 3C); a $117 million increase from accounts payable; and a $106 million increase from income taxes, net. The increase from accounts receivable was primarily driven by the settlement of $234 million of derivative receivables related to derivative contracts for our former synthetic fuels businesses (See Note 17A). The increase from income taxes, net was largely due to $252 million in income tax payments made in 2007 related to the sale of natural gas drilling and production business, partially offset by income tax impacts at PEC. The change in accounts payable was primarily related to our divested operations.

In 2009, 2008 and 2007, the Utilities filed requests with their respective state commissions seeking rate increases for fuel cost recovery, including amounts for previous under-recoveries.

INVESTING ACTIVITIES

Net cash used by investing activities for the three years ended December 31, 2009, 2008 and 2007, was $2.532 billion, $2.541 billion and $1.457 billion, respectively.

Property additions at the Utilities, including nuclear fuel, were $2.488 billion and $2.534 billion in 2009 and 2008, respectively, or approximately 100 percent of consolidated capital expenditures in both 2009 and 2008. 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 $1 million in 2009 and $72 million in 2008, cash used in investing activities decreased by $80 million. The decrease in 2009 was primarily due to a $24 million decrease in gross property additions at the Utilities, primarily due to lower spending for environmental compliance projects and the completion of PEF's Bartow Plant repowering project in 2009; a $22 million decrease in nuclear fuel additions; and a $20 million decrease in net purchases of available-for-sale securities and other investments. Available-for-sale securities and other investments include marketable debt securities and investments held in nuclear decommissioning trusts.

Excluding proceeds from sales of discontinued operations and other assets, net of cash divested of $72 million in 2008 and $675 million in 2007, cash used in investing activities increased by $481 million. The increase in 2008 was primarily due to a $341 million increase in gross property additions at the Utilities, primarily at PEF, and a $95 million decrease in net purchases of available-for-sale securities and other investments. The increase in capital expenditures for utility property additions at PEF was primarily driven by a $360 million increase in environmental compliance expenditures and a $109 million increase in nuclear project expenditures, partially offset by a $65 million decrease related to repowering the Bartow Plant to more efficient natural gas-burning technology and a $52 million decrease related to the Hines 4 facility.

During 2008, proceeds from sales of discontinued operations and other assets primarily included proceeds of $63 million from the sale of Terminals and Coal Mining (See Notes 3A and 3B).

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 3C), working capital adjustments related to the sale of natural gas drilling and production business, and the sale of poles at Progress Telecommunications Corporation.

FINANCING ACTIVITIES

Net cash provided by financing activities for the three years ended December 31, 2009, 2008 and 2007, was $806 million, $1.248 billion and $195 million, respectively. See Note 11 for details of debt and credit facilities.

The decrease in net cash provided by financing activities for 2009 compared to 2008 is primarily due to a $2.077 billion net decrease in short-term indebtedness, primarily driven by commercial paper repayments and the Parent's repayment of borrowings outstanding under its RCA; partially offset by a $491 million increase in proceeds from the issuance of common stock, primarily related to the Parent's January 2009 common stock offering; a $481 million increase in net proceeds from long-term debt issuances due to the Parent's combined $1.700 billion issuances and PEC's $600 million issuance in 2009 compared to PEF's $1.500 billion issuance and PEC's $325 million issuance in 2008; a $477 million decrease in payments at maturity of long-term debt; and a $118 million decrease in net payments on short-term debt with original maturities greater than 90 days.

The increase in net cash provided by financing activities for 2008 compared to 2007 is primarily due to PEF's $1.475 billion net proceeds and PEC's $322 million net proceeds from the issuance of long-term debt in 2008 discussed below, compared to $739 million in net proceeds in 2007. Additionally, net short-term debt increased in 2008 compared to 2007 due to $600 million in outstanding borrowings under the Parent's RCA, and outstanding commercial paper issuances of $69 million at the Parent, $110 million at PEC and $371 million at PEF, compared to outstanding commercial paper issuances of $201 million at the Parent in 2007. The increase in proceeds from long-term debt issuances was offset by $877 million in long-term debt retirements in 2008; $176 million in payments on short-term debt; and $85 million in cash distributions to owners of minority interests of consolidated subsidiaries primarily related to the settlement of Ceredo Synfuel LLC's (Ceredo) synthetic fuels derivatives contracts (See Note 17A).

Our financing activities are described below.

2010

- On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with proceeds from the $950 million of Senior Notes issued in November 2009.

- Subsequent to December 31, 2009, the Parent has issued approximately 3.6 million shares of common stock resulting in approximately $136 million in proceeds through the IPP.

2009

- On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were approximately $523 million. On February 3, 2009, the Parent used $100 million of the proceeds to reduce its $600 million RCA balance outstanding at December 31, 2008, and the remainder was used for general corporate purposes.
- On January 15, 2009, PEC issued $600 million of First Mortgage Bonds, 5.30% Series due 2019. A portion of the proceeds was used to repay the maturity of PEC's $400 million 5.95% Senior Notes, due March 1, 2009. The remaining proceeds were used to repay PEC's outstanding short-term debt and for general corporate purposes.
- On March 19, 2009, the Parent issued an aggregate $750 million of Senior Notes consisting of $300 million of 6.05% Senior Notes due 2014 and $450 million of 7.05% Senior Notes due 2019. A portion of the proceeds was used to fund PEF's capital expenditures through an equity contribution with the remaining proceeds used for general corporate purposes.
- On June 18, 2009, PEC entered into a Seventy-seventh Supplemental Indenture to its Mortgage and Deed of Trust, dated May 1, 1940, as supplemented, in connection with certain amendments to the mortgage. The amendments are set forth in the Seventy-seventh Supplemental Indenture and include an amendment to extend the maturity date of the mortgage by 100 years. The maturity date of the mortgage is now May 1, 2140.
- On November 19, 2009, the Parent issued an aggregate $950 million of Senior Notes consisting of $350 million of 4.875% Senior Notes due 2019 and $600 million of 6.00% Senior Notes due 2039. The proceeds were used to retire at maturity the $100 million outstanding Series A Floating Rate Notes due January 15, 2010, to repay outstanding commercial paper balances, to pre-fund a portion of the $700 million aggregate principal amount due upon maturity of our 7.10% Senior Notes due March 1, 2011, and for general corporate purposes.
- During 2009, we repaid the November 2008 $600 million borrowing under our RCA.
- Progress Energy issued approximately 3.1 million shares of common stock resulting in approximately $100 million in proceeds from its IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 2.5 million shares for proceeds of approximately $100 million issued for the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the IPP. For 2009, the dividends paid on common stock were approximately $693 million.

2008

- On February 1, 2008, PEF paid at maturity $80 million of its 6.875% First Mortgage Bonds with available cash on hand and commercial paper borrowings.
- On March 12, 2008, PEC and PEF amended their RCAs with a syndication of financial institutions to extend the termination date by one year. The extensions were effective for both utilities on March 28, 2008. PEC's RCA is now scheduled to expire on June 28, 2011, and PEF's RCA is now scheduled to expire on March 28, 2011 (See "Credit Facilities and Registration Statements").
- On March 13, 2008, PEC issued $325 million of First Mortgage Bonds, 6.30% Series due 2038. The proceeds were used to repay the maturity of PEC's $300 million 6.65% Medium-Term Notes, Series D, due April 1, 2008, and the remainder was placed in temporary investments for general corporate use as needed.
- On April 14, 2008, the Parent amended its RCA with a syndication of financial institutions to extend the termination date by one year. The extension was effective on May 2, 2008. The RCA is now scheduled to expire on May 3, 2012 (See "Credit Facilities and Registration Statements").
- On May 27, 2008, Progress Capital Holdings, Inc., one of our wholly owned subsidiaries, paid at maturity its remaining outstanding debt of $45 million of 6.46% Medium-Term Notes with available cash on hand.
- On June 18, 2008, PEF issued $500 million of First Mortgage Bonds, 5.65% Series due 2018 and $1.000 billion of First Mortgage Bonds, 6.40% Series due 2038. A portion of the proceeds was used to repay PEF's utility money pool borrowings, and the remaining proceeds were placed in temporary investments for general corporate use as needed. On August 14, 2008, PEF redeemed the entire outstanding $450 million principal amount of its Series A Floating Rate Notes due November 14, 2008, at 100 percent of par plus accrued interest. The redemption was funded with a portion of the proceeds from the June 18, 2008 debt issuance.
- On November 3, 2008, the Parent borrowed $600 million under its RCA to reduce rollover risk in the commercial paper markets. The borrowing was repaid during 2009.

- On November 18, 2008, the Parent, as a well-known seasoned issuer, PEC and PEF filed a combined shelf registration statement with the SEC, which became effective upon filing with the SEC. The registration statement is effective for three years and does not limit the amount or number of various securities that can be issued (See "Credit Facilities and Registration Statements").
- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $132 million in proceeds from its IPP and its employee benefit and equity incentive plans. Included in these amounts were approximately 3.1 million shares for proceeds of approximately $131 million issued for the 401(k) and the IPP. For 2008, the dividends paid on common stock were approximately $642 million.

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 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.
- Progress Energy issued approximately 3.7 million shares of common stock resulting in approximately $151 million in proceeds from its IPP and its equity incentive plans. Included in these amounts were approximately 1.0 million shares for proceeds of approximately $46 million issued for the IPP. For 2007, the dividends paid on common stock were approximately $627 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, 2009, 2008 and 2007. We anticipate that the Utilities will continue to produce substantially all of the consolidated cash flows from operations over the next several years. Our discontinued synthetic fuels operations historically produced significant net earnings from the generation of tax credits (See "Other Matters – Synthetic Fuels Tax Credits"). A portion of these tax credits has yet to be realized in cash due to the difference in timing of when tax credits are recognized for financial reporting purposes and realized for tax purposes. At December 31, 2009, we have carried forward $712 million of deferred tax credits. Realization of these tax credits is dependent upon our future taxable income, which is expected to be generated primarily by the Utilities.

We expect to be able to meet our future liquidity needs through cash from operations, commercial paper issuance, availability under our credit facilities, long-term debt financings and equity offerings. We may also use periodic ongoing sales of common stock from our IPP and employee benefit and stock option plans to meet our liquidity requirements.

We issue commercial paper to meet short-term liquidity needs. As a result of financial and economic conditions in 2008 and 2009, the short-term credit markets tightened, resulting in volatility in commercial paper durations and interest rates. The Parent borrowed $600 million under its RCA in November 2008 and repaid the outstanding balance during 2009 with proceeds from the January 2009 equity issuance, cash on hand and proceeds from commercial paper borrowings. If liquidity conditions deteriorate again and negatively impact the commercial paper market, we will need to evaluate other, potentially more expensive, options for meeting our short-term liquidity needs, which may include borrowing under our RCA, issuing short-term notes, issuing long-term debt and/or issuing equity. If our short-term credit ratings are downgraded below Tier 2

(A-2/P-2/F2), we could experience increased volatility in commercial paper durations and interest rates and our access to the commercial paper markets could be negatively impacted. In the event of a downgrade of our senior unsecured credit ratings, our credit facility fees and borrowing rates under our RCAs could increase. We do not expect an increase in such RCA fees to be material. See "Credit Rating Matters" for further discussion regarding credit ratings.

The current RCAs for the Parent, PEC and PEF expire in May 2012, June 2011 and March 2011, respectively. We are currently evaluating options for addressing these upcoming expirations. In the event we enter into new credit facilities, we cannot predict the terms, prices, durations or participants in such facilities.

Progress Energy and its subsidiaries have approximately $12.051 billion in outstanding long-term debt. Currently, approximately $860 million of the Utilities' debt obligations, approximately $620 million at PEC and approximately $240 million at PEF, are tax-exempt auction rate securities insured by bond insurance. These tax-exempt bonds have experienced and continue to experience failed auctions. Assuming the failed auctions persist, future interest rate resets on our tax-exempt auction rate bond portfolio will be dependent on the volatility experienced in the indices that dictate our interest rate resets and/or rating agency actions that may move our tax-exempt bonds below A3/A-. PEC's senior secured debt ratings are currently A1 by Moody's Investors Service, Inc. (Moody's) and A-/Watch Negative by Standard and Poor's Rating Services (S&P). PEF's senior secured debt ratings are currently A1/Watch Negative by Moody's and A-/Watch Negative by S&P. In the event of a one notch downgrade of PEC's and/or PEF's senior secured debt rating by S&P, the ratings of both utilities' tax-exempt bonds would be below A-, most likely resulting in higher future interest rate resets. In the event of a one notch downgrade by Moody's, PEC's and PEF's tax-exempt bonds will continue to be rated above A3. We will continue to monitor this market and evaluate options to mitigate our exposure to future volatility.

The performance of the capital markets affects the values of the assets held in trust to satisfy future obligations under our defined benefit pension plans. Although a number of factors impact our pension funding requirements, a decline in the market value of these assets may significantly increase the future funding requirements of the obligations under our defined benefit pension plans. We expect to make at least $120 million of contributions directly to pension plan assets in 2010 (See Note 16).

As discussed in "Strategy," "Liquidity and Capital Resources," "Capital Expenditures," and in "Other Matters – Environmental Matters," over the long term, compliance with environmental regulations and meeting the anticipated load growth at the Utilities as described under "Other Matters – Increasing Energy Demand" will require the Utilities to make significant capital investments. 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/or 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. As discussed in "Other Matters – Nuclear – Potential New Construction," PEF expects its capital expenditures for the Levy project will be significantly less in the near term than previously planned in light of a regulatory schedule shift and other factors.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. Substantially all derivative commodity instrument positions are subject to retail regulatory treatment. After settlement of the derivatives and consumption of the fuel, any realized gains or losses are passed through the fuel cost-recovery clause. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted the amount of collateral posted with counterparties. At February 19, 2010, we had posted approximately $168 million of cash collateral compared to $146 million of cash collateral posted at December 31, 2009. The majority of our financial hedge agreements will settle in 2010 and 2011. Additional commodity market price decreases could result in significant increases in the derivative collateral that we are required to post with counterparties. We continually monitor our derivative positions in relation to market price activity. In addition, as discussed in "Credit Rating Matters," if our credit ratings are downgraded, we may have to post additional cash collateral for derivatives in a liability position.

The amount and timing of future sales of debt and equity securities will depend on market conditions, operating cash flow 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, 2009, the current portion of our long-term debt was $406 million. On January 15, 2010, we funded the $100 million Series A Floating Rate Notes maturity with proceeds from the Parent's November 2009 $950 million long-term debt issuance, and we expect to fund the remaining $306 million with a combination of cash from operations,commercial paper borrowings and long-term debt.

See "Credit Rating Matters" for information regarding recent rating actions.

REGULATORY MATTERS AND RECOVERY OF COSTS

Regulatory matters, including nuclear cost recovery, as discussed in Note 7 and "Other Matters – Regulatory Environment," 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. Regulatory developments expected to have a material impact on our liquidity are discussed below.

As discussed further in Note 7 and in "Other Matters – Regulatory Environment," the North Carolina, South Carolina and Florida legislatures passed energy legislation that became law in recent years. These laws may impact our liquidity over the long term, including, among others, provisions regarding cost recovery, mandated renewable portfolio standards, DSM and energy efficiency.

PEC Cost-Recovery Clause

On May 7, 2009, PEC filed with the SCPSC for a decrease in the fuel rate charged to its South Carolina ratepayers. On June 19, 2009, the SCPSC approved a settlement agreement filed jointly by PEC and the South Carolina Office of Regulatory Staff and Nucor Steel. Under the terms of the settlement agreement, the parties agreed to PEC's proposed rate reduction of approximately $13 million, which went into effect July 1, 2009.

On June 4, 2009, PEC filed with the North Carolina Utilities Commission (NCUC) for a decrease in the fuel rate charged to its North Carolina ratepayers. The filing was updated on August 17, 2009. PEC asked the NCUC to approve a $14 million decrease in the fuel rates driven by declining fuel prices, which went into effect December 1, 2009. At December 31, 2009, PEC's North Carolina deferred fuel balance was $148 million, of which $62 million is expected to be collected after 2010.

PEC Other Matters

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

As discussed in Note 7 and in "Other Matters – Environmental Matters," on October 22, 2009, the NCUC issued an order granting PEC a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C., to replace three coal-fired generating units at the site that have a combined generating capacity of approximately 400 MW. We intend to continue to depreciate the three coal-fired units at their current depreciation rate until PEC's next depreciation study. PEC projects that the generating facility would be in service by January 2013. The filed estimate of capital expenditures, net of AFUDC–borrowed funds for the new generating facility is approximately $800 million. PEC modified its Clean Smokestacks Act compliance plan for the change in fuel source and removed retrofitting PEC's Sutton Plant with emission-reduction technology from the plan. Accordingly, PEC filed a revised estimate with the NCUC, which decreased estimated capital expenditures to meet the Clean Smokestacks Act emission targets by 2013 to $1.1 billion from $1.4 billion. We are continuing to evaluate various design, technology, generation and fuel options, including retiring some coal-fired plants that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

In accordance with the October 2009 NCUC order, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. We intend to continue to depreciate the coal-fired units at their current depreciation rate until PEC's next depreciation study. On December 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C. The filed estimate of capital expenditures, net of AFUDC–borrowed funds for the new generating facility is approximately $600 million. PEC projects that the generating facility would be in service by late 2013 or early 2014.

PEF Base Rates

As a result of a base rate proceeding in 2005, PEF was party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and remained in effect through the last billing cycle of December 2009.

On March 20, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF filed with the FPSC a proposal for an increase in base rates effective January 1, 2010. In its filing, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and approve annual rate relief for PEF of $499 million, which included PEF's petition for a combined $76 million of new base rates in 2009 as discussed below. The request for increased base rates was based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems.

Included within the base rate proposal was a request for an interim base rate increase of $13 million. Additionally, on March 20, 2009, PEF petitioned the FPSC for a limited proceeding to include in base rates revenue requirements of $63 million for the repowered Bartow Plant, which began commercial operations in June 2009. On May 19, 2009, the FPSC approved both the annualized interim base rate increase and the cost recovery for the repowered Bartow Plant subject to refund with interest effective July 1, 2009. The interim and limited base rate relief increased revenues by $79 million during the year ended December 31, 2009.

On January 11, 2010, the FPSC approved a base rate increase of $132 million effective January 1, 2010, which represents the annualized impact of the rate increase that was approved and effective July 2009 for the repowered Bartow Plant. Additionally, the FPSC did not require PEF to refund the 2009 interim base rate increase previously discussed. The difference between PEF's requested $499 million incremental revenues and the $132 million granted by the FPSC is a function of several factors, including, among other things: 1) PEF had proposed rates based on a return on equity of 12.54 percent and the FPSC granted rates based on a return on equity of 10.5 percent; 2) the FPSC granted rates based on projected annual depreciation expense that is approximately $119 million lower than the amount requested by PEF; and 3) the FPSC's ruling incorporates projected annual O&M costs that are approximately $77 million lower than the O&M cost requested by PEF and the elimination of $15 million of annual storm reserve accrual, which represented a $9 million increase over the accrual previously in effect. We are currently reviewing our regulatory options.

PEF Cost-Recovery Clauses

On March 17, 2009, PEF received approval from the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $206 million reduction in fuel charges to retail customers as a result of effective fuel-purchasing strategies and lower fuel prices. The approval reduced customers' fuel charges starting with the first billing cycle of April 2009.

On September 14, 2009, PEF filed a request with the FPSC to seek approval of a cost adjustment to reduce fuel costs by $105 million, thereby decreasing residential electric bills by $3.34 per 1,000 kWh, or 2.6 percent, effective January 1, 2010. On October 23, 2009, PEF filed a $3 million cost adjustment with the FPSC, which reduced the capacity cost-recovery clause (CCRC) rate by $0.08 per 1,000 kWh from the original September 14, 2009 cost adjustment filing. The FPSC approved PEF's fuel and capacity clause filings on November 2, 2009, to be effective January 1, 2010.

In addition, on August 28, 2009 and as updated on October 27, 2009, PEF filed a request to increase the ECRC residential rate. Also, on September 14, 2009, PEF filed a request to increase the ECCR residential rate. The FPSC approved a combined $37 million increase in PEF's ECRC and ECCR clauses on November 2, 2009, to be effective January 1, 2010.

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers. The FPSC has approved cost recovery of PEF's prudently incurred costs necessary to achieve its integrated strategy to address compliance with CAIR, the Clean Air Mercury Rule (CAMR) and the Clean Air Visibility Rule (CAVR) through the ECRC (See "Other Matters – Environmental Matters" for discussion regarding the CAIR, CAMR and CAVR).

Nuclear Cost Recovery

PEF is allowed to recover prudently incurred site selection costs, preconstruction costs and the carrying cost on construction cost balances on an annual basis through the CCRC. Such amounts will not be included in PEF's rate base when the plant is placed in commercial operation. The nuclear cost-recovery rule also has a provision to recover costs should the project be abandoned after the utility receives a final order granting a Determination of Need. These costs include any unrecovered construction work in progress at the time of abandonment and any other prudent and reasonable exit costs. In addition, the rule requires the FPSC to conduct an annual prudence review of the reasonableness and prudence of all such costs, including construction costs, and such determination shall not be subject to later review except upon a finding of fraud, intentional misrepresentation or the intentional withholding of key information by the utility. On November 19, 2009, the FPSC issued a final order approving the recovery of prudently incurred nuclear costs through the CCRC, and found that PEF's project management, contracting, and oversight controls were reasonable and prudent. As discussed in Note 7, on October 16, 2009, the FPSC clarified certain implementation policies related to the recognition of deferrals and the application of carrying charges under the nuclear cost-recovery rule.

On March 17, 2009, PEF received approval from the FPSC to defer until 2010 the recovery of $198 million of nuclear preconstruction costs for Levy, which the FPSC had authorized to be collected in 2009. The approval reduced customers' nuclear cost-recovery charge starting with the first billing cycle of April 2009.

On May 1, 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consists of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. This alternate proposal reduced the 2010 revenue requirement to $236 million. On September 14, 2009, consistent with FPSC rules, PEF included both proposed revenue requirements in its CCRC filing. At a special agenda hearing by the FPSC on October 16, 2009, the FPSC approved the alternate proposal allowing PEF to recover $207 million through the nuclear cost-recovery clause of the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. In adopting PEF's proposed rate plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts.

CAPITAL EXPENDITURES

Total cash from operations and proceeds from long-term debt and equity issuances provided the funding for our capital expenditures, including environmental compliance and other utility property additions, nuclear fuel expenditures and non-utility property additions during 2009.

As shown in the table that follows, we expect the majority of our capital expenditures to be incurred at our regulated operations. We expect to fund our capital requirements primarily through a combination of 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. AFUDC–borrowed funds represents the debt costs of capital funds necessary to finance the construction of new regulated plant assets.

	Actual	Forecasted		
(in millions)	2009	2010	2011	2012
Regulated capital expenditures	$1,995	$2,160	$2,120	$1,810
Nuclear fuel expenditures	200	230	300	260
AFUDC-borrowed funds	(37)	(30)	(40)	(40)
Other capital expenditures	7	30	30	30
Total before potential nuclear construction	2,165	2,390	2,410	2,060
Potential nuclear construction[a]	291	100–150	60–70	60–70
Total	$2,456	$2,490–2,540	$2,470–2,480	$2,120–2,130

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

Regulated capital expenditures for 2010, 2011 and 2012 in the previous table include approximately $130 million, $40 million and $100 million, respectively, for environmental compliance capital expenditures. Forecasted environmental compliance capital expenditures for 2010, 2011 and 2012 include $20 million, $40 million and $50 million, respectively, at PEC. Forecasted environmental compliance capital expenditures for 2010 and 2012 include $110 million and $50 million, respectively, at PEF. No environmental compliance capital expenditures are forecasted for PEF in 2011. See "Other Matters – Environmental Matters" for further discussion of our environmental compliance costs and related recovery of costs.

Potential nuclear construction expenditures, which are primarily for PEF's Levy, include development, licensing and equipment. Forecasted potential nuclear construction expenditures are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages of joint ownership. Because of anticipated schedule shifts, we are negotiating an amendment to the Levy EPC agreement (See discussion under "Other Matters – Nuclear – Potential

New Construction"). The forecasted capital expenditures presented in the previous table reflect the anticipated impact of such amendment. If Levy is deferred or cancelled, PEF may incur contract suspension, termination and/or exit costs. The magnitude of these contract suspension, termination and/or exit costs cannot be determined at this time and, accordingly, are not included in the previous table. Potential nuclear construction expenditures are subject to cost-recovery provisions in the Utilities' respective jurisdictions. Forecasted potential nuclear construction expenditures for 2010, 2011 and 2012 include approximately $70 million, $30 million and $30 million, respectively, of preconstruction expenditures, which are eligible for recovery under Florida's nuclear cost-recovery rule.

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

CREDIT FACILITIES AND REGISTRATION STATEMENTS

At December 31, 2009 and 2008, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2009, we had no outstanding borrowings under our credit facilities. At December 31, 2008, we had $600 million of outstanding borrowings under our credit facilities as shown in the table below, of which $100 million was classified as long-term debt. We are required to pay minimal annual commitment fees to maintain our credit facilities.

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

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 11 for additional discussion of our credit facilities.

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

All of the credit facilities include defined maximum total debt-to-total capital ratio (leverage) covenants, which we were in compliance with at December 31, 2009. We are currently in compliance and expect to continue to be in compliance with these covenants. See Note 11 for a discussion of the credit facilities' financial covenants. At December 31, 2009, the calculated ratios pursuant to the terms of the agreements are as disclosed in Note 11.

(in millions)	Description	Total	Outstanding[a]	Reserved[b]	Available
2009					
Parent	**Five-year (expiring 5/3/12)**	**$1,130**	**$–**	**$177**	**$953**
PEC	**Five-year (expiring 6/28/11)**	**450**	**–**	**–**	**450**
PEF	**Five-year (expiring 3/28/11)**	**450**	**–**	**–**	**450**
Total credit facilities		**$2,030**	**$–**	**$177**	**$1,853**
2008					
Parent	Five-year (expiring 5/3/12)	$1,130	$600	$99	$431
PEC	Five-year (expiring 6/28/11)	450	–	110	340
PEF	Five-year (expiring 3/28/11)	450	–	371	79
Total credit facilities		$2,030	$600	$580	$850

[a] The RCA borrowings outstanding at December 31, 2008, were repaid during 2009.

[b] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009 and 2008, the Parent had a total amount of $37 million and $30 million, respectively, of letters of credit issued, which were supported by the RCA. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper with proceeds from the $950 million November 2009 issuance of Senior Notes.

The Parent, as a well-known seasoned issuer, has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various securities, including senior debt securities, junior subordinated debentures, common stock, preferred stock, stock purchase contracts, stock purchase units, and trust preferred securities and guarantees.

PEC has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount of various long-term debt securities and preferred stock.

PEF has on file with the SEC a shelf registration statement under which it may issue an unlimited number or amount 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 based on property additions, retirements of first mortgage bonds and the deposit of cash, provided that adjusted net earnings are at least twice the annual interest requirement for bonds currently outstanding and to be outstanding. At December 31, 2009, PEC and PEF could issue up to approximately $6.0 billion and $2.6 billion of first mortgage bonds, respectively, based on property additions and retirements of previously issued first mortgage bonds. At December 31, 2009, PEC's and PEF's ratios of adjusted net earnings to annual interest requirement on outstanding first mortgage bonds were 4.9 times and 3.4 times, respectively.

CAPITALIZATION RATIOS

The following table shows our capitalization ratios at December 31:

	2009	2008
Total equity	42.3%	41.9%
Preferred stock	0.4%	0.5%
Total debt	57.3%	57.6%

CREDIT RATING MATTERS

At February 22, 2010, the major credit rating agencies rated our securities as follows:

Long-Term Ratings	Moody's Investors Service	Standard & Poor's	Fitch Ratings
Parent			
Outlook/Watch	Watch Negative[a]	Watch Negative[b]	Stable
Corporate credit rating	n/a	BBB+	BBB
Senior unsecured debt	Baa2	BBB	BBB
PEC			
Outlook/Watch	Stable	Watch Negative[b]	Stable
Corporate credit rating	A3	BBB+	A-
Senior secured debt	A1	A-	A+
Senior unsecured debt	A3	BBB+	A
Subordinate debt	Baa1	n/a	n/a
Preferred stock	Baa2	BBB-	BBB+
PEF			
Outlook/Watch	Watch Negative[a]	Watch Negative[b]	Watch Negative[c]
Corporate credit rating	A3	BBB+	A-
Senior secured debt	A1	A-	A+
Senior unsecured debt	A3	BBB+	A
Preferred stock	Baa2	BBB-	BBB+
Florida Progress Corporation (FPC) Capital I			
Outlook/Watch	Watch Negative[a]	Watch Negative[b]	Watch Negative[c]
Quarterly Income Preferred Securities[d]	Baa2	BBB-	BBB+
Short-Term Ratings			
Parent			
Watch	Watch Negative[a]	N/A	N/A
Commercial paper	P-2	A-2	F2
PEC			
Watch	N/A	N/A	N/A
Commercial paper	P-2	A-2	F1
PEF			
Watch	N/A	N/A	Watch Negative[c]
Commercial paper	P-2	A-2	F1

[a] On January 19, 2010, Moody's placed these ratings on review for possible downgrade.
[b] On January 14, 2010, S&P placed these ratings on CreditWatch Negative.
[c] On January 12, 2010, Fitch placed these ratings on Rating Watch Negative.
[d] Guaranteed by the Parent and FPC.

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 August 3, 2009, Moody's raised the senior secured debt rating of both PEC and PEF to A1 from A2 as a result of Moody's reevaluating its notching criteria for investment-grade regulated utilities to reflect the historical lower default rates for regulated utilities than for non-financial, non-utility corporate issuers.

On January 12, 2010, Fitch placed ratings of PEF and FPC Capital I on Rating Watch Negative as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. Fitch cited lower cash flow expectations and increased regulatory risk as drivers for the rating action.

On January 14, 2010, S&P placed ratings of Progress Energy, Inc. and its subsidiaries, including PEC, PEF, FPC Capital I and Florida Progress Corp., on CreditWatch Negative as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. At the same time, S&P affirmed the A-2 short-term ratings on Progress Energy, Inc., PEC and PEF.

On January 19, 2010, Moody's placed the long-term ratings of Progress Energy, Inc. and PEF on review for possible downgrade as a result of the January 11, 2010 ruling by the FPSC in the PEF base rate case proceeding. Moody's also placed the short-term rating for commercial paper of Progress Energy, Inc. on review for possible downgrade. At the same time, Moody's affirmed the ratings and stable outlook of PEC.

As noted above, the three rating agencies cited increased regulatory risk and PEF's rate case outcome as the key driver of the ratings actions. Credit rating changes could be made after the agencies have completed their reviews of PEF's rate order and our response to the decision.

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

As discussed in Note 17C, credit rating downgrades could also require us to post additional cash collateral for commodity hedges in a liability position as certain derivative instruments require us to post collateral on liability positions based on our credit ratings.

On January 22, 2010, Fitch lowered the rating on PEC's, PEF's and FPC Capital I's preferred securities to BBB+ from A- as a result of the implementation of Fitch's revised guidelines for rating preferred stock and hybrid securities.

OFF-BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

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

Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to Progress Energy or our subsidiaries on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees include standby letters of credit, surety bonds, performance obligations for trading operations and guarantees of certain subsidiary credit obligations. At December 31, 2009, we have issued $406 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). Subsequent to December 31, 2009, the Parent issued a $76 million guarantee for performance assurance of a wholly owned indirect subsidiary. 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, 2009, we have issued guarantees and indemnifications of certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses, and for timely payment of obligations in support of our nonwholly owned synthetic fuels operations as discussed in Note 22C.

Market Risk and Derivatives

Under our risk management policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. See Note 17 and "Quantitative and Qualitative Disclosures About Market Risk" for a discussion of market risk and derivatives.

Contractual Obligations

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

The following table reflects Progress Energy's contractual cash obligations and other commercial commitments at December 31, 2009, 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 11)	$12,515	$406	$1,950	$1,125	$9,034
Interest payments on long-term debt[b]	10,077	707	1,289	1,073	7,008
Capital lease obligations[c] (See Note 22B)	484	34	67	74	309
Operating leases[c] (See Note 22B)	1,430	35	83	181	1,131
Fuel and purchased power[d] (See Note 22A)	24,070	3,092	5,202	3,923	11,853
Other purchase obligations[e] (See Note 22A)	9,749	1,872	3,288	2,883	1,706
Minimum pension funding requirements[f]	794	74	353	229	138
Other postretirement benefits[g] (See Note 16A)	397	34	73	79	211
Uncertain tax positions[h] (See Note 14)	–	–	–	–	–
Other commitments[i]	105	13	26	26	40
Total	$59,621	$6,267	$12,331	$9,593	$31,430

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

[b] Interest payments on long-term debt are based on the interest rate effective at December 31, 2009.

[c] Amounts include certain related executory cost commitments.

[d] Essentially all fuel and certain purchased power costs incurred by the Utilities are recovered through cost-recovery clauses in accordance with state and federal regulations and therefore do not require separate liquidity support.

[e] Amounts primarily relate to an EPC agreement that PEF entered into in December 2008 for two nuclear units planned for construction at Levy. The contractual obligations presented are in accordance with the existing terms of the EPC agreement, which assumes the original construction schedule and 100 percent ownership by PEF. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. Because of anticipated schedule shifts, we are negotiating an amendment to the EPC agreement (See discussion under "Other Matters–Nuclear–Potential New Construction.") We cannot currently predict the impact such amendment might have on the amount and timing of PEF's contractual obligations. If Levy is deferred or cancelled, PEF may incur contract suspension, termination and/or exit costs. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time and, accordingly, are not reflected in this table.

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

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

[h] Uncertain tax positions of $160 million are not reflected in this table as we cannot predict when open income tax years will be closed with completed examinations. It is reasonably possible that the total amounts of unrecognized tax benefits will decrease by up to approximately $60 million during the 12-month period ending December 31, 2010, due to expected settlements.

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

OTHER MATTERS

Regulatory Environment

The Utilities' operations in North Carolina, South Carolina and Florida are regulated by the NCUC, the SCPSC and the FPSC, respectively. The Utilities are also subject to regulation by the FERC, the NRC and other federal and state agencies common to the utility business. As a result of regulation, many of the fundamental business decisions, as well as the rate of return the Utilities are permitted 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 American Recovery and Reinvestment Act, signed into law in February 2009, contains provisions promoting energy efficiency and renewable energy, including $3.4 billion in Smart Grid technology development grants; $615 million for Smart Grid storage, monitoring and technology viability; $6.3 billion for energy-efficiency and conservation grants; and $2 billion in tax credits for the purchase of plug-in electric vehicles. In August 2009, we submitted our application to the United States Department of Energy (DOE) for $200 million in federal matching infrastructure funds in support of our investment in Smart Grid-related technologies in the Carolinas and Florida. On October 27, 2009, the DOE notified us of our selection for Smart Grid award negotiations. We are now awaiting further questions and comments from the DOE on our Smart Grid application. The submission of an application and the notification for award negotiations are not a commitment to accept federal funds but are necessary steps to keep the option open. We are currently evaluating the provisions of the law and assessing the conditions imposed by participation in the incentive programs. Also, the Obama administration has announced a goal of encouraging investment in transmission and promoting renewable resources while also pricing GHG emissions and setting a federal requirement for renewable energy.

On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009. This bill would establish a national cap-and-trade program to reduce GHG emissions as well as a national renewable energy portfolio standard (REPS). The bill also calls for investment in the electric grid, more production and utilization of electric vehicles and improvements in energy efficiency in buildings and appliances. The full impact of the legislation, if enacted into law, cannot be determined at this time and will depend upon changes made to its provisions during the legislative process and the manner in which key provisions are implemented, including the regulation of carbon. The U.S. Senate is considering similar proposals. The full impact of final legislation, if enacted, and additional regulation resulting from these and other federal GHG initiatives cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time, for which the Utilities would seek corresponding rate recovery.

Current retail rate matters affected by state regulatory authorities are discussed in Notes 7B and 7C. This discussion identifies specific retail rate matters, the status of the issues and the associated effects on our consolidated financial statements.

On July 31, 2009, the governor of North Carolina signed into law a bill that includes three key provisions that may impact PEC. First, the legislation accelerates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal unit at that specific site. Pursuant to the legislation, PEC requested and received approval from the NCUC to pursue construction of a new 950-MW natural gas plant (see further discussion in Note 7B and "Other Matters – Environmental Matters"). Second, a recovery mechanism is provided for utilities if they invest in zero emissions renewable energy facilities within the next five years. Finally, the legislation changes the state's Dam Safety Act such that dams at utility coal-fired power plants, including dams for ash ponds, will be subject to the Act's applicable provisions, including state inspection, as of January 1, 2010.

Florida energy law enacted in 2008 includes provisions that would, among other things, (1) help enhance the ability to cost-effectively site transmission lines; (2) require the FPSC to develop a renewable portfolio standard that the FPSC would present to the legislature for ratification in 2009; (3) direct the Florida Department of Environmental Protection (FDEP) to develop rules establishing a cap-and-trade program to regulate GHG emissions that the FDEP would present to the legislature no earlier than January 2010 for ratification by the legislature; and (4) establish a new Florida Energy and Climate Commission as the principal governmental body to develop energy and climate policy for the state and to make recommendations to the governor and legislature on energy and climate issues. In complying with the provisions of the law, PEF would be able to recover its reasonable prudent compliance costs. However, until these agency actions are finalized, we cannot predict the costs of complying with the law.

On July 13, 2007, the governor of Florida issued executive orders to address reduction of GHG emissions. The executive orders call for the first southeastern state cap-and-trade program and include adoption of a maximum allowable emissions level of GHGs 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. To date, the FDEP has held three rulemaking workshops on the GHG cap-and-trade rulemaking. Rulemaking is expected to continue through 2010, and the rule requires legislative ratification before implementation.

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 onsite renewable technologies of up to 1 MW in capacity to offset their consumption over a billing period by allowing their electric meters to turn backward when they generate electricity (net metering). On January 12, 2009, the FPSC approved a draft Florida renewable portfolio standard rule with a goal of 20 percent renewable energy production by 2020. The FPSC provided the draft Florida renewable portfolio standard rule to the Florida legislature in February 2009, but the legislature did not take action in the 2009 session. We cannot predict the outcome of this matter.

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

North Carolina energy law enacted in 2007 includes provisions for a North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS), expansion of the definition of the traditional fuel clause and recovery of the costs of new DSM and energy-efficiency programs through an annual DSM clause. On February 29, 2008, the NCUC issued an order adopting final rules for implementing North Carolina's 2007 energy law. The rules include filing requirements regarding NC REPS compliance and inclusion in the Utility's integrated resource plan. The order also establishes a schedule and filing requirements for DSM and energy-efficiency cost recovery and financial incentives. Rates for the DSM and energy-efficiency clause and the NC REPS clause will be set based on projected costs with true-up provisions. PEC has implemented a series of DSM and energy-efficiency programs and will continue to pursue additional programs. These programs must be approved by the NCUC, and we cannot predict the outcome of filings currently pending approval by the NCUC or whether the implemented programs will produce the expected operational and economic results.

Energy Demand

Implementing state and federal energy policies, promoting environmental stewardship and providing reliable electricity to meet the anticipated long-term growth within the Utilities' service territories will require a balanced approach. The three main elements of this balanced solution are: (1) expanding our 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 DSM, energy-efficiency and conservation programs because energy efficiency is one of the most effective ways to reduce energy costs, offset the need for new power plants and protect the environment. DSM programs include programs and initiatives that shift the timing of electricity use from peak to nonpeak periods, such as load management, electricity system and operating controls, direct load control, interruptible load, and electric system equipment and operating controls. We provide our residential customers with home energy audits and offer energy-efficiency programs that provide incentives for customers to implement measures that reduce energy use. For business customers, we also provide energy audits and other tools, including an interactive Internet Web site with online calculators, programs and efficiency tips, to help them reduce their energy use.

We are actively engaged in a variety of alternative energy projects to pursue the generation of electricity from swine waste and other plant or animal sources, biomass, solar, hydrogen, and landfill-gas technologies. Among our projects, we have executed contracts to purchase approximately 250 MW of electricity generated from biomass and up to 60 MW of electricity generated from municipal solid waste sources. The majority of these projects should be online within the next five years. In addition, we have executed purchased power agreements for approximately 10 MW of electricity generated from solar photovoltaic generation as part of the NC REPS. The majority of these projects are online and the remainder should be online by early 2010. Additionally, customers across our service territory have connected approximately 4 MW of solar photovoltaic energy systems to our grid. In June 2009, we expanded our solar energy strategy to include a range of new solar incentives and programs, which are expected to increase our use of solar energy by more than 100 MW over the next decade.

In the coming years, we will continue to invest in existing plants and consider plans for building new generating plants. Due to the anticipated long-term 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.

In 2009, PEC announced a coal-to-gas modernization strategy whereby the 11 remaining coal-fired generating facilities in North Carolina that do not have scrubbers would be retired prior to the end of their useful lives and their approximately 1,500 MW of generating capacity replaced with new natural gas-fueled facilities. The coal-fired units will be retired by the end of 2017. PEC has received approval from the NCUC for construction of a 950-MW natural gas-fueled generating facility at a site in Wayne County, N.C., to be placed in service in January 2013. PEC has requested approval from the NCUC to construct a 620-MW natural gas-fueled generating facility at a site in New Hanover County, N.C. The facility is projected to be placed in service in late 2013 or early 2014. PEC will continue to operate three coal-fired plants in North Carolina after 2017. PEC has invested more than $2 billion in installing state-of-the-art emission controls at the Roxboro, Mayo and Asheville Plants. Emissions of NOx, SO_2, mercury and other pollutants have been reduced significantly at those sites.

As authorized under the Energy Policy Act of 2005 (EPACT), on October 4, 2007, the 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.

In 2008, Congress authorized $38.5 billion in loan guarantee authority for innovative energy projects. Of the total provided, $18.5 billion is set aside for nuclear power facilities, $2 billion for advanced nuclear facilities for the "front-end" of the nuclear fuel cycle, $10 billion for renewable and/or energy-efficient systems and manufacturing and distributed energy generation/transmission and distribution, $6 billion for coal-based power generation and industrial gasification at retrofitted and new facilities that incorporate carbon capture and sequestration or other beneficial uses of carbon, and $2 billion for advanced coal gasification. In June 2008, the DOE announced solicitations for a total of up to $30.5 billion of the amount authorized by Congress in federal loan guarantees for projects that employ advanced energy technologies that avoid, reduce or sequester air pollutants or greenhouse gas emissions and advanced nuclear facilities for the "front-end" of the nuclear fuel cycle.

PEF submitted Part I of the Application for Federal Loan Guarantees for Nuclear Power Facilities on September 29, 2008, for Levy. PEF was one of 19 applicants that submitted Part I of the application. The program requires that the guarantee be in a first lien position on all assets of the project, which conflicts with PEF's current mortgage. Obtaining the required approval to amend the current mortgage from 100 percent of PEF's current bondholders would be unlikely, and current secured debt of $4.0 billion would need to be refinanced with unsecured debt to meet the requirements of the guarantee. In addition, the costs associated with obtaining the loan guarantee are unclear. PEF decided not to pursue the loan guarantee program and did not submit Part II of the application, which was due on December 19, 2008. However, this decision does not preclude PEF from revisiting the program at a later date if there are changes to the program. We cannot predict if PEF will pursue this program further.

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 filed 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.

Nuclear

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

CR3 is currently undergoing an extended outage for normal refueling and maintenance as well as a project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination within the concrete of the outer wall of the containment structure. PEF is finalizing the root cause determination of the delamination event and the necessary repair plans. At present, PEF does not have a firm return to service date for CR3, finalized repair estimates and replacement power costs, or the impact of insurance recovery. However, the costs to repair the delamination and associated costs of an outage extension, such as fuel, purchased power and maintenance, could be material. Based on the current understanding of the cause of the delamination event and the conceptual repair strategy, PEF expects that CR3 will return to service in mid-2010.

The NRC operating licenses for PEC's nuclear units are currently operating under licenses that expire between 2010 and 2026. The NRC has granted PEC 20-year renewals of the licenses for its nuclear units, which extend the operating licenses to expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On March 9, 2009, the NRC docketed, or accepted for review, PEF's application for a 20-year renewal on the operating license for CR3, which would extend the operating license through 2036, if approved. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will renew the license. The license renewal application for CR3 is currently under review by the NRC with a decision expected in 2011.

POTENTIAL NEW CONSTRUCTION

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

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEC's application submission. On February 19, 2008, PEC filed its COL application with the NRC for two additional reactors at Harris. On April 17, 2008, the NRC docketed, or accepted for review, the Harris application. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. No petitions to intervene have been admitted in the Harris COL application. If we receive approval from the NRC and applicable state agencies, and if the decisions to build are made, a new plant would not be online until at least 2019 (See "Energy Demand" above).

On December 12, 2006, we announced that PEF selected a greenfield site at Levy to evaluate for possible future nuclear expansion. We selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base PEF's application submission. In 2007, PEF completed the purchase of approximately 5,000 acres for Levy and associated transmission needs. In 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. On May 29, 2008, the Florida Department of Community Affairs issued its final determination that the amendments to the Levy County Comprehensive Plan are in compliance with land use regulations.

In 2008, PEF submitted filings for two key state approvals. First, on March 11, 2008, PEF filed a Petition for a Determination of Need for Levy with the FPSC. The FPSC issued a final order granting PEF's petition for Levy on August 12, 2008. Second, on June 2, 2008, PEF filed its application for site certification with the FDEP. Certification addresses permitting, land use and zoning, and property interests and replaces state and local permits. Certification grants approval for the location of the power plant and its associated facilities such as roadways and electrical transmission lines carrying power to the electrical grid, among others. Certification does not include licenses required by the federal government. On January 12, 2009, the FDEP filed a favorable staff analysis report in advance of certification hearings. The technical proceedings concluded on March 12, 2009, and the administrative law judge issued a recommended order on certification on May 15, 2009. The Power Plant Siting Board, comprised of the governor and the Cabinet, issued the Levy certification on August 26, 2009.

On July 30, 2008, PEF filed its COL application with the NRC for two reactors. PEF also completed and submitted a Limited Work Authorization request for Levy concurrent with the COL application. On October 6, 2008, the NRC docketed, or accepted for review, the Levy application. Docketing the application does not preclude additional requests for information as the review proceeds, nor does it indicate whether the NRC will issue the license. On February 24, 2009, PEF received the NRC's schedule for review and approval of the COL. One joint petition to intervene in the licensing proceeding was filed with the NRC within the 60-day notice period by the Green Party of Florida, the Nuclear Information and Resource Service and the Ecology Party of Florida. On April 20-21, 2009, the Atomic Safety Licensing Board (ASLB) heard oral arguments on whether any of the joint interveners' proposed contentions will be admitted in the Levy COL proceeding. On July 8, 2009, the ASLB issued a decision accepting three of the 12 contentions submitted. The admitted contentions involved questions about the storage of low-level radioactive waste, the potential impacts of plant construction and operation on the aquifer and surrounding waters and the potential impact of salt water drift from cooling tower operation. PEF's appeal of the ASLB's decision was denied and a hearing on the contentions will be conducted in 2011. Other COL applicants have received similar petitions raising similar potential contentions. We cannot predict the outcome of this matter.

PEF expects a schedule shift for the commercial operation dates of the Levy nuclear units. PEF's initial schedule anticipated the ability to perform certain site work pursuant to a Limited Work Authorization from the NRC prior to COL receipt. However, in 2009, the NRC Staff determined that certain schedule-critical work that PEF had proposed to perform within the Limited Work Authorization scope will not be authorized until the NRC issues the COL. Consequently, excavation and foundation preparation work will be shifted until after COL issuance. This factor alone resulted in a minimum 20-month schedule shift later than the originally anticipated 2016 to 2018 timeframe. Additional schedule shifts are likely given, among other things, the permitting and licensing process, state of Florida and macro-economic conditions, recent FPSC DSM and energy-efficiency goals and other decisions. Uncertainty regarding access to capital on reasonable terms could be another factor to affect the Levy schedule. In light of the regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Later in 2010, PEF will file its annual nuclear cost-recovery filing with the FPSC, which will reflect our latest plan regarding Levy.

As discussed below, the schedule shift will reduce the near-term capital expenditures for the project and also reduce the near-term impact on customer rates. The schedule shift will also allow more time for certainty around federal climate change policy, which is currently being debated. We believe that continuing, although at a slower pace than initially anticipated, is a reasonable and prudent course at this early stage of the project. We still consider Levy as PEF's preferred baseload generation option, taking into account cost, potential carbon regulation, fossil fuel price volatility and the benefits of fuel diversification. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including public, regulatory and political support; adequate financial cost-recovery mechanisms; customer rate impacts; project feasibility; and availability and terms of capital financing.

PEF signed the EPC agreement on December 31, 2008, with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two Westinghouse AP1000 nuclear units to be constructed at Levy. More than half of the approximate $7.650 billion contract price is fixed or firm with agreed upon escalation factors. The total escalated cost for the two generating units was estimated in PEF's petition for the Determination of Need for Levy to be approximately $14 billion. This total cost estimate includes land, plant components, financing costs, construction, labor, regulatory fees and the initial core for the two units. An additional $3 billion was estimated for the necessary transmission equipment and approximately 200 miles of transmission lines associated with the project. The EPC agreement includes various incentives, warranties, performance guarantees, liquidated damage provisions and parent guarantees designed to incent the contractor to perform efficiently. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. We anticipate amending the EPC agreement due to the schedule shift previously discussed but cannot predict the impact such amendment might have on the project's cost, if any.

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

In 2008, PEF sought and received approval from the FPSC to recover Levy preconstruction and carrying charges of $357 million as well as site selection costs of $38 million through the 2009 CCRC. In 2009, PEF received approval to defer until 2010 the recovery of $198 million of these costs (See Note 7C). On October 16, 2009, the FPSC approved the recovery of $201 million of preconstruction costs, carrying costs and incremental O&M incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with Levy as part of the total $207 million FPSC-approved recovery of nuclear costs through the 2010 CCRC (See Note 7C).

At December 31, 2009, PEF's unrecovered investment in Levy totaled $404 million, of which $358 million is recoverable in retail rates through the Florida nuclear cost-recovery rules, including $296 million of construction work in progress, $274 million of which was reflected as a regulatory asset pursuant to accelerated regulatory recovery of nuclear costs and $22 million was reflected as a deferred fuel regulatory asset. The remaining $46 million is apportioned to PEF's wholesale jurisdiction and would be recovered through PEF's wholesale rates. If Levy is deferred or cancelled, PEF may incur additional contract suspension, termination and/or exit costs that would increase its unrecovered investment. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time.

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

SPENT NUCLEAR FUEL MATTERS

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. We have a contract with the DOE for the future storage and disposal of our spent nuclear fuel. Delays have occurred in the DOE's proposed permanent repository to be located at Yucca Mountain, Nev. The Obama administration has determined that Yucca Mountain, Nev., is not a workable option for a nuclear waste repository and will discontinue its program to construct a repository at this site in 2010. The administration will continue to explore alternatives. Debate surrounding any new strategy likely will address centralized interim storage, permanent storage at multiple sites and/or spent nuclear fuel reprocessing. We cannot predict the outcome of this matter.

The NRC has proposed revisions to its waste confidence findings that would remove the provisions stating that the NRC's confidence in waste management, underlying the licensing of reactors, is based in part on a permanent repository being in operation by 2025. Instead, the NRC states that repository capacity will be available within 50 to 60 years beyond the licensed operation of all reactors, and that used fuel generated in any reactor can be safely stored on site without significant environmental impact for at least 60 years beyond the licensed operation of the reactor. We cannot predict the outcome of this matter.

On September 15, 2009, the NRC proposed licensing requirements for storage of spent nuclear fuel, which would clarify the term limits for specific licenses for independent spent fuel storage installations and for certificates of compliance for spent nuclear fuel storage casks. The agency proposal would formalize the site-by-site exemption the NRC has used for renewal applications requesting more than the current 20-year duration. The initial and renewal terms of a specific installation license would be effective for a period of up to 40 years. Similarly, the proposed rule would allow applicants for certificates of compliance to request initial and renewal terms of up to 40 years, provided they can demonstrate that all design requirements are satisfied for the requested term. We cannot predict the outcome of this matter.

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

See Note 22D for information about the complaint filed by the Utilities in the United States Court of Federal Claims against the DOE for its failure to fulfill its contractual obligation to receive spent fuel from nuclear plants. Failure to open the Yucca Mountain or other facility would leave the DOE open to further claims by utilities.

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.

HAZARDOUS AND SOLID WASTE MANAGEMENT

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liability. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida or potentially responsible parties (PRP) groups. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses (See Notes 7 and 21). Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted. Hazardous and solid waste management matters are discussed in detail in Note 21A.

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

As discussed in "Other Matters – Regulatory Environment," as of January 1, 2010, dams at utility fossil-fired power plants, including dams for ash ponds, are subject to the North Carolina Dam Safety Act's applicable provisions, including state inspection. Until the state agency responsible for dam safety inspects each of the affected dams, we cannot predict if additional safety-related measures will be required. However, these dams have been subject to periodic third-party inspection in accordance with prior applicable requirements.

The EPA and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion products, primarily ash, from each of the Utilities' coal-fired plants. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or groundwater protection environmental controls. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures under existing regulations. These issues are also under evaluation by state agencies. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary.

In June 2009, the EPA evaluated information about ash impoundment dams nationwide and posted a listing of 44 utility ash impoundment dams that are considered to have "high hazard potential," including two of PEC's ash impoundment dams. A "high hazard potential" rating is not related to the stability of those ash ponds but to the potential for harm should the impoundment dam fail. As noted above, all of the dams at PEC's coal ash ponds have been subject to periodic third-party inspection. In September 2009, the EPA rated the 44 "high hazard potential" impoundments, as well as other impoundments, from "unsatisfactory" to "satisfactory" based on their structural integrity and associated documentation.

Only dams rated as "unsatisfactory" would be considered to pose an immediate safety threat, but none of the facilities received an "unsatisfactory" rating. In total, six of PEC's ash pond dams, including one "high hazard potential" impoundment, were rated as "poor" based on the contract inspector's desire to see additional documentation and their evaluations of vegetation management and minor erosion control. Inspectors applied the same criteria to both active and inactive ash ponds, despite the fact that most of the inactive ash impoundments no longer hold water and do not pose a risk of breaching and spilling. PEC has completed several of the recommendations for the active ponds and other recommendations are under way. We are working with the North Carolina Dam Safety program to evaluate the remaining recommendations. We do not expect mitigation of these issues to have a material impact on our results of operations.

AIR QUALITY AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations, which likely would result in increased capital expenditures and O&M expenses. Additionally, Congress is considering legislation that would require reductions in air emissions of NOx, 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 installed pursuant to the provisions of CAIR, CAVR and mercury regulations, which are discussed below, may address some of the issues outlined above. PEC and PEF have been developing an integrated compliance strategy to meet the requirements of the CAIR, CAVR and mercury regulation (see discussion of the court decisions that impacted the CAIR, the delisting determination and the CAMR below). The CAVR requires the installation of best available retrofit technology (BART) on certain units. However, the outcome of these matters cannot be predicted.

Clean Smokestacks Act

In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of NOx and SO_2 from their North Carolina coal-fired power plants in phases by 2013. PEC currently has approximately 5,000 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act. On March 31, 2009, 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 $1.4 billion at the time of the filing. As discussed in "Other Matters – Regulatory Environment," North Carolina enacted a law in July 2009 that abbreviates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal units at that specific site. The law gives PEC the option to seek certification, construct a new natural gas plant and retire existing coal units, with resulting reduced emissions, in time to comply with the Clean Smokestacks Act's 2013 emission targets. As discussed in Note 7B, on October 22, 2009, the NCUC issued an order granting PEC a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C., to replace three coal-fired generating units at the site that have a combined generating capacity of approximately 400 MW. PEC projects that the generating facility would be in service by January 2013. On December 1, 2009, PEC filed with the NCUC a plan to retire, no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. PEC modified its Clean Smokestacks Act compliance plan to remove retrofitting PEC's Sutton Plant with emission-reduction technology from the plan. Accordingly, PEC filed a revised estimate with the NCUC totaling $1.1 billion of capital expenditures to meet the Clean Smokestacks Act emission targets. We are continuing to evaluate various design, technology, generation and fuel options, including retiring some coal-fired plants that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

O&M expenses increase with the operation of pollution control equipment due to the cost of reagents, additional personnel and general maintenance associated with the pollution control equipment. PEC is allowed to recover the cost of reagents and certain other costs under its fuel clause; all other O&M expenses are currently recoverable through base rates.

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).

Clean Air Interstate Rule

The CAIR issued by the EPA on March 10, 2005, required the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO_2 emissions. The CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2. States were required to adopt rules implementing the CAIR, and the EPA approved the North Carolina CAIR, the South Carolina CAIR and the Florida CAIR in 2007.

The air quality controls installed to comply with the requirements of the NOx State Implementation Plan Call Rule under Section 110 of the Clean Air Act (NOx SIP Call) and Clean Smokestacks Act, as well as plans to replace a portion of PEC's coal-fired generation with gas-fueled generation, largely address the CAIR requirements for our North Carolina units at PEC. PEF met the 2009 phase I requirements for NOx and anticipates meeting the 2010 phase I requirements of CAIR for NOx and SO_2 with a combination of emission reductions generated by in-service emission control equipment and emission allowances. PEF's CR5 equipment was placed in service on December 2, 2009, and PEF's CR4 equipment is expected to be placed in service in 2010.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, which vacated the CAIR in its entirety. On December 23, 2008, the D.C. Court of Appeals remanded the CAIR, without vacating the rule, for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. This decision leaves the CAIR in effect until such time that it is revised or replaced. The EPA informed the D.C. Court of Appeals that development and finalization of a replacement rule could take approximately two years. The outcome of this matter cannot be predicted.

Under an agreement with the FDEP, PEF will retire Crystal River Units No. 1 and 2 coal-fired steam turbines (CR1 and CR2) and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was anticipated to be around 2020. PEF is required to advise the FDEP of any developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated completion date of the first fuel cycle for Levy Unit 2. Accordingly, PEF has advised the FDEP of an expected shift in the Levy schedule as discussed in "Other Matters – Nuclear – Potential New Construction." We are currently evaluating the impacts of the Levy schedule. We cannot predict the outcome of this matter.

Clean Air Mercury Rule

On March 15, 2005, the EPA finalized two separate but related rules: the CAMR that set mercury emissions limits to be met in two phases beginning in 2010 and 2018, respectively, and encouraged a cap-and-trade approach to achieving those caps, and a delisting rule that eliminated any requirement to pursue a maximum achievable control technology (MACT) approach for limiting mercury emissions from coal-fired power plants. On February 8, 2008, the D.C. Court of Appeals vacated the delisting determination and the CAMR. The U.S. Supreme Court declined to hear an appeal of the D.C. Court of Appeals' decision in January 2009. As a result, the EPA subsequently announced that it will develop a MACT standard consistent with the agency's original listing determination. The three states in which the Utilities operate adopted mercury regulations implementing the CAMR and submitted their state implementation rules to the EPA. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. The outcome of this matter cannot be predicted.

Clean Air Visibility Rule

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, designated as Class I areas. To help restore visibility in those areas, states must require the identified facilities to install BART to control their emissions. PEC's BART-eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEF's BART-eligible units are Anclote Units No. 1 and No. 2, CR1 and CR2. The reductions associated with BART begin in 2013. As discussed above, on December 18, 2008, PEF and the FDEP announced an agreement under which PEF will retire CR1 and CR2 as coal-fired units.

The CAVR included the EPA's determination that compliance with the NOx and SO_2 requirements of the CAIR could be used by states as a BART substitute to fulfill BART obligations, but the states could require the installation of additional air quality controls if they did not achieve reasonable progress in improving visibility. The D.C. Court of Appeals' December 23, 2008 decision remanding the CAIR maintained its implementation such that CAIR satisfies BART for SO_2 and NOx. Should this determination change as the CAIR is revised, CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions for BART-eligible units. We are assessing the potential impact of BART and its implications with respect to our plans and estimated costs to comply with the CAVR. On December 4, 2007, the FDEP finalized a Regional Haze implementation rule that goes beyond BART by requiring sources significantly impacting visibility in Class I areas to install additional controls by December 31, 2017. However, the FDEP has not determined the level of additional controls PEF may need to implement. The outcome of these matters cannot be predicted.

Compliance Strategy

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

PEC has completed installation of controls to meet the NOx SIP Call requirements. The NOx SIP Call is not applicable to sources in Florida. Expenditures for the NOx SIP Call included the cost to install NOx controls under programs by North Carolina and South Carolina to comply with the federal eight-hour ozone standard.

The FPSC approved PEF's petition to develop and implement an Integrated Clean Air Compliance Plan to comply with the CAIR, CAMR and CAVR and for recovery of prudently incurred costs necessary to achieve this strategy through the ECRC (See discussion above regarding the vacating of the CAMR and remanding of the CAIR). PEF's April 1, 2009 filing with the FPSC for true-up of final 2008 environmental costs included a review of the Integrated Clean Air Compliance Plan, which reconfirmed the efficacy of the recommended plan and included an estimated total project cost of approximately $1.2 billion to be spent through 2016, to plan, design, build and install pollution control equipment at the Anclote and Crystal River plants. As discussed in Note 7C, on August 28, 2009, PEF filed for recovery of costs through the ECRC, and the FPSC approved PEF's filing on November 2, 2009. Additional costs may be incurred if pollution controls are required in order to comply with the requirements of the CAVR, as discussed above, or to meet revised compliance requirements of a revised or new implementing rule for the CAIR. Subsequent rule interpretations, increases in the underlying material, labor and equipment costs, equipment availability, or the unexpected acceleration of compliance dates, among other things, could result in significant increases in our estimated costs to comply and acceleration of some projects. The outcome of this matter cannot be predicted.

Environmental Compliance Cost Estimates

Environmental compliance cost estimates are dependent upon a variety of factors and, as such, are highly uncertain and subject to change. Factors impacting our environmental compliance cost estimates include new and frequently changing laws and regulations; the impact of legal decisions on environmental laws and regulations; changes in the demand for, supply of and costs of labor and materials; changes in the scope and timing of projects; various design, technology and new generation options; and projections of fuel sources, prices, availability and security. Costs to comply with environmental laws and regulations are eligible for regulatory recovery through either base rates or cost-recovery clauses. The outcome of future petitions for recovery cannot be predicted. Our estimates of capital expenditures to comply with environmental laws and regulations are subject to periodic review and revision and may vary significantly. We cannot predict the impact that the EPA's further CAIR proceedings will have on our compliance with the CAVR requirements and will continue to reassess our plans and estimated costs to comply with the CAVR. The timing and extent of the costs for future projects will depend upon final compliance strategies.

The following table contains information about our current estimates of capital expenditures to comply with environmental laws and regulations described above. Amounts presented in the table exclude AFUDC.

Air and Water Quality Estimated Required Environmental Expenditures *(in millions)*	Estimated Timetable	Total Estimated Expenditures	Cumulative Spent through December 31, 2009
Clean Smokestacks Act[a]	2002 – 2013	$1,100	$1,050
In-process CAIR projects[b]	2005 – 2010	1,200	1,065
CAVR[c]	– 2017	–	–
Mercury regulation[d]	2006 – 2017	–	4
Total air quality		2,300	2,119
Clean Water Act Section 316(b)[e]		–	–
Total air and water quality		$2,300	$2,119

[a] We are continuing to evaluate various design, technology and new generation options that could change expenditures required to maintain compliance with the Clean Smokestacks Act limits subsequent to 2013.

[b] We are continuing construction of our in-process emission control projects. Additional compliance plans to meet the requirements of a revised rule will be determined upon finalization of the rule. See discussion under "Clean Air Interstate Rule."

[c] As a result of the decision remanding the CAIR, compliance plans and costs to meet the requirements of the CAVR are being reassessed. See discussion under "Clean Air Visibility Rule."

[d] Compliance plans to meet the requirements of a revised or new implementing rule will be determined upon finalization of the rule. See discussion under "Clean Air Mercury Rule."

[e] 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."

All environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, which included projects at PEC's Asheville, Lee, Mayo and Roxboro plants, have been placed in service. On December 1, 2009, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. Additional projects requiring material environmental compliance costs may be implemented in the future to meet compliance requirements.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at CR5 and CR4. The CR5 project was placed in service on December 2, 2009, and the CR4 project is expected to be placed in service in 2010. As a result of changes in the scope of work related to estimation of costs for compliance with the CAIR and the uncertainty regarding the EPA's further CAIR proceedings, the delisting determination and the CAMR discussed above, PEF is currently unable to estimate certain costs of compliance. However, PEF believes that future costs to comply with new or subsequent rule interpretations could be significant. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when those new regulations are finalized.

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 fossil fuel-fired power plants in 13 other states, including South Carolina, to reduce their NOx and SO_2 emissions. The state of North Carolina contends these out-of-state emissions interfere with North Carolina's ability to meet National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. In 2006, the EPA issued a final response denying the petition, and the North Carolina attorney general filed a petition in the D.C. Court of Appeals seeking a review of the agency's denial. In 2009, the D.C. Court of Appeals remanded the EPA's denial to the agency for reconsideration. The outcome of the remand proceeding cannot be predicted.

National Ambient Air Quality Standards

In 2006, the EPA announced changes to the NAAQS for particulate matter. The changes in particulate matter standards did not result in designation of any additional nonattainment areas in PEC's or PEF's service territories. Environmental groups and 13 states filed a joint petition with the D.C. Court of Appeals arguing that the EPA's particulate matter rule does not adequately restrict levels of particulate matter, especially with respect to the annual and secondary standards. On February 24, 2009, the D.C. Court of Appeals remanded the annual and secondary standards to the EPA for further review and consideration. The outcome of this matter cannot be predicted.

In 2008, the EPA revised the 8-hour primary and secondary standards for the NAAQS for ground-level ozone. Additional nonattainment areas may be designated in PEC's and PEF's service territories as a result of these revised standards. On May 27, 2008, a number of states, environmental groups and industry associations filed petitions against the revised NAAQS in the D.C. Court of Appeals. The EPA requested the D.C. Court of Appeals to suspend proceedings in the case while the EPA evaluates whether to maintain, modify or otherwise reconsider the revised NAAQS. In September 2009, the EPA announced that it is reconsidering the level of the ozone NAAQS. The EPA originally indicated plans to designate nonattainment areas for these standards by March 2010. However, the EPA announced that it will stay those designations until after its reconsideration has been completed.

On January 7, 2010, the EPA announced a proposed revision to the primary ozone NAAQS. In addition, the EPA proposed a cumulative seasonal secondary standard. The EPA plans to finalize the revisions by August 31, 2010, and to designate nonattainment areas by August 2011. The proposed revisions are significantly more stringent than the current NAAQS. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of this matter cannot be predicted.

On January 25, 2010, the EPA announced a revision to the primary NAAQS for nitrogen dioxide. Since 1971, when the first NAAQS were promulgated, the standard for nitrogen dioxide has been an annual average. The EPA has retained the annual standard and added a new 1-hour NAAQS. In conjunction with proposing changes to the standard, the EPA is also requiring an increase in the coverage of the monitoring network, particularly near roadways where the highest concentrations are expected to occur due to traffic emissions. The EPA plans to designate nonattainment areas by January 2012. Currently, there are no monitors reporting violation of the new standard in PEC's or PEF's service territories, but the expanded monitoring network will provide additional data, which could result in additional nonattainment areas. The outcome of this matter cannot be predicted.

On December 8, 2009, the EPA proposed a new 1-hour NAAQS for sulfur dioxide. The current primary NAAQS on a 24-hour average basis and annual average would be eliminated under the proposed rule. A 1-hour standard in the proposed range is a significant increase in the stringency of the standard and it would increase the risk of nonattainment, especially near uncontrolled coal-fired facilities. Should additional nonattainment areas be designated in our service territories, we may be required to install additional emission controls at some of our facilities. The outcome of this matter cannot be predicted.

New Source Review

The EPA is conducting an enforcement initiative related to a number of coal-fired utility power plants to determine whether changes at those facilities were subject to New Source Review 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 included reported expenditures in excess of $1.0 billion for retrofit of pollution control equipment. These settlement agreements have generally called for expenditures to be made over extended time periods, and some of the unaffiliated utilities may seek recovery of the related costs through rate adjustments or similar mechanisms.

Water Quality

1. General

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

On September 15, 2009, the EPA announced that it had completed a multi-year study of power plant wastewater discharges and concluded that current regulations have not kept pace with changes in the electric power industry since the regulations were issued in 1982, including addressing impacts to wastewater discharge from operation of air pollution control equipment. As a result, the EPA has announced that it plans to revise the regulations that govern wastewater discharge, which may result in operational changes and additional compliance costs in the future. The outcome of this matter cannot be predicted.

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

Section 316(b) 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) with respect to existing power plants in July 2004.

A number of states, environmental groups and others sought judicial review of the July 2004 rule. In 2007, the U.S. Court of Appeals for the Second Circuit issued an opinion and order remanding many provisions of the rule to the EPA, and the EPA suspended the rule pending further rulemaking, with the exception of the requirement that permitted facilities must meet any requirements under Section 316(b) as determined by the permitting authorities on a case-by-case, best professional judgment basis. Several parties filed petitions for writ of certiorari to the U.S. Supreme Court. On April 1, 2009, the U.S. Supreme Court issued its opinion holding that the EPA, in selecting the "best technology" pursuant to Section 316(b), does have the authority to reject technology when its costs are "wholly disproportionate" to the benefits expected. Also, the U.S. Supreme Court held that EPA's site-specific variance procedure (contained in the July 2004 rule) was permissible in that the procedure required testing to determine whether costs would be "significantly greater than" the benefits before a variance would be considered. As a result of these developments, our plans and associated estimated costs to comply with Section 316(b) will need to be reassessed and determined in accordance with any revised or new implementing rule after it is established by the EPA. Costs of compliance with a revised or new implementing rule are expected to be higher, and could be significantly higher, than estimated costs under the July 2004 rule. Our cost estimates to comply with the July 2004 rule were $60 million to $90 million. The outcome of this matter cannot be predicted.

OTHER ENVIRONMENTAL MATTERS

Global Climate Change

Growing state, federal and international attention to global climate change may result in the regulation of CO_2 and other GHGs. As discussed under "Other Matters – Regulatory Environment," on June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009. This bill would establish a national cap-and-trade program to reduce GHG emissions as well as a national REPS. The U.S. Senate is considering similar proposals. Final legislation will depend upon changes made during the legislative process to the provisions and the manner in which key provisions are implemented, including for the regulation of carbon. In addition, the Obama administration has begun the process of regulating GHG emissions through use of the Clean Air Act. On April 2, 2007, the U.S. Supreme Court ruled that the EPA has the authority under the Clean Air Act to regulate CO_2 emissions from new automobiles. On December 15, 2009, the EPA announced that six GHGs (CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride) pose a threat to public health and welfare under the Clean Air Act. A number of parties have filed petitions for review of this finding in the D.C. Court of Appeals. The full impact of final legislation, if enacted, and additional regulation resulting from other federal GHG initiatives cannot be determined at this time; however, we anticipate that it could result in significant cost increases over time for which the Utilities would seek corresponding rate recovery. We are preparing for a carbon-constrained future and are actively engaged in helping shape effective policies to address the issue.

As discussed under "Other Matters – Regulatory Environment," in 2008 the state of Florida passed comprehensive energy legislation, which includes a directive that the FDEP develop rules to establish a cap-and-trade program to regulate GHG emissions that would be presented to the legislature no earlier than January 2010. The FDEP is currently in the process of studying GHG policy options and the potential economic impacts, but it has not developed a regulation for the consideration of the legislature. As discussed under "Clean Smokestacks Act," on July 31, 2009, the governor of North Carolina signed into law a bill that may impact PEC's Clean Smokestacks Act compliance plans. While state-level study groups have been active in all three of our jurisdictions, we continue to believe that this issue requires a national policy framework – one that provides certainty and consistency. Our balanced solution as discussed in "Other Matters – Energy Demand" is a comprehensive plan to meet the anticipated demand in the Utilities' service territories and provides a solid basis for slowing and reducing CO_2 emissions by focusing on energy efficiency, alternative energy and state-of-the-art power generation.

There are ongoing efforts to reach a new international climate change treaty to succeed the Kyoto Protocol. The Kyoto Protocol was adopted in 1997 by the United Nations to address global climate change by reducing emissions of CO_2 and other GHGs. Although the treaty went into effect on February 16, 2005, the United States has not adopted it. In December 2009, the United Nations Framework Convention on Climate Change convened the 15th Conference of the Parties to conduct further negotiations on GHG emissions reductions. At the conclusion of the conference, a number of the parties, including the United States, entered into a nonbinding accord calling upon the parties to submit emission reduction targets for 2020 to the United Nations Framework Convention on Climate Change Secretariat by the end of January 2010. On January 28, 2010, President Obama submitted a proposal to reduce the U.S. GHG emissions in the range of 17 percent below 2005 levels by 2020, subject to future congressional action.

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

Prior to 2009, the EPA received waiver requests from a number of states to allow those states to set standards for CO_2 emissions from new vehicles. The EPA denied those requests. On January 26, 2009, the Obama administration requested the EPA to review those denials of waiver requests. On June 30, 2009, the EPA granted California's waiver request, enabling the state to enforce its GHG emissions standards for new motor vehicles, beginning with the current model year. Additional states may set similar standards as a result of the decision. The impact of this development cannot be predicted.

On September 22, 2009, the EPA issued the final GHG emissions reporting rule, which establishes a national protocol for the reporting of annual GHG emissions. Facilities that emit greater than 25,000 metric tons per year of GHGs must report emissions by March 31 of each year beginning in 2011 for year 2010 emissions. Because the rule builds on current emission-reporting requirements, compliance with the requirements is not expected to have a material impact on the Utilities.

Synthetic Fuels Tax Credits

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

Legislation enacted in 2005 redesignated the Section 29 tax credit as a general business credit under Section 45K of the Code 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 removed the regular federal income tax liability limit on synthetic fuels production and subjects the credits to a one-year carry back period and a 20-year carry forward period.

Total Section 29/45K credits generated under the synthetic fuels tax credit program (including those generated by Florida Progress prior to our acquisition) were \$1.891 billion, \$1.179 billion of which has been used through December 31, 2009, to offset regular federal income tax liability and \$712 million is being carried forward as deferred tax credits.

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

Legal

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

New Accounting Standards

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various risks related to changes in market conditions. Market risk represents the potential loss arising from adverse changes in market rates and prices. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we may use a variety of instruments, including swaps, options and forward contracts, to manage exposure to fluctuations in commodity prices and interest rates. Such instruments contain credit risk to the extent that the counterparty fails to perform under the contract. We minimize such risk by performing credit and financial reviews using a combination of financial analysis and publicly available credit ratings of such counterparties (See Note 17). Both PEC and PEF also have limited counterparty exposure for commodity hedges (primarily gas and oil hedges) by spreading concentration risk over a number of counterparties.

The following disclosures about market risk contain forward-looking statements that involve estimates, projections, goals, forecasts, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Please review "Safe Harbor for Forward-Looking Statements" for a discussion of the factors that may impact any such forward-looking statements made herein.

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

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

Interest Rate Risk

As part of our debt portfolio management and daily cash management, we have variable rate long-term debt and typically have commercial paper and/or loans outstanding under our RCA facilities, which are also exposed to floating interest rates. Approximately 9 percent and 18 percent of consolidated debt had variable rates at December 31, 2009 and 2008, respectively.

Based on our variable rate long-term debt balances at December 31, 2009, a 100 basis point change in interest rates would result in an annual pre-tax interest expense change of approximately $10 million. Based on our short-term debt balances at December 31, 2009, a 100 basis point change in interest rates would result in an insignificant annual pre-tax interest expense change.

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

The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by a counterparty, the exposure in the transaction is the cost of replacing the agreements at current market rates.

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

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

The following tables provide information at December 31, 2009 and 2008, 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 forward contracts, the tables present notional amounts and weighted-average interest rates by contractual mandatory termination dates for 2010 to 2014 and thereafter and the related fair value. Notional amounts are used to calculate the settlement amounts under the interest rate forward contracts. See Note 17 for more information on interest rate derivatives.

(dollars in millions) December 31, 2009	2010	2011	2012	2013	2014	Thereafter	Total	Fair Value December 31, 2009
Fixed-rate long-term debt	$306	$1,000	$950	$825	$300	$7,864	$11,245	$12,126
Average interest rate	4.53%	6.95%	6.67%	4.96%	6.05%	6.13%	6.12%	
Variable-rate long-term debt	$100	–	–	–	–	$861	$961	$961
Average interest rate	0.73%	–	–	–	–	0.45%	0.48%	
Debt to affiliated trust[a]	–	–	–	–	–	$309	$309	$315
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate forward contracts[b]	$75	$150	$100	–	–	–	$325	$19
Average pay rate	3.48%	4.03%	4.07%	–	–	–	3.91%	
Average receive rate	[c]	[c]	[c]	–	–	–	[c]	

[a] FPC Capital I – Quarterly Income Preferred Securities.
[b] Notional amount of 10-year forward starting swaps are categorized by mandatory cash settlement date.
[c] Rate is 3-month London Inter Bank Offered Rate (LIBOR), which was 0.25% at December 31, 2009.

(dollars in millions) December 31, 2008	2009	2010	2011	2012	2013	Thereafter	Total	Fair Value December 31, 2008
Fixed-rate long-term debt	$–	$306	$1,000	$950	$825	$6,265	$9,346	$9,909
Average interest rate	–	4.53%	6.96%	6.67%	4.96%	6.21%	6.17%	
Variable-rate long-term debt	–	$100	–	$100	–	$861	$1,061	$1,061
Average interest rate	–	5.20%	–	2.52%	–	1.90%	2.27%	
Debt to affiliated trust[a]	–	–	–	–	–	$309	$309	$290
Interest rate	–	–	–	–	–	7.10%	7.10%	
Interest rate forward contracts[b]	$450	–	–	–	–	–	$450	$(65)
Average pay rate	4.26%	–	–	–	–	–	4.26%	
Average receive rate	[c]	–	–	–	–	–	[c]	

[a] FPC Capital I – Quarterly Income Preferred Securities.
[b] Notional amount of 10-year forward starting swaps are categorized by mandatory cash settlement date.
[c] Rate is 3-month LIBOR, which was 1.43% at December 31, 2008.

During January 2010, Progress Energy entered into $175 million notional of forward starting swaps to mitigate exposure to interest rate risk in anticipation of future debt issuances, including $75 million notional at PEF.

At December 31, 2009, Progress Energy had $325 million notional of open forward starting swaps, including $100 million notional at PEC and $75 million notional at PEF.

At December 31, 2008, Progress Energy had $450 million notional of open forward starting swaps, including $250 million notional at PEC. At December 31, 2007, Progress Energy had $200 million notional of open forward starting swaps, all at PEC.

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, 2009 and 2008, the fair value of these funds was $1.367 billion and $1.089 billion, respectively. We actively monitor our portfolio by benchmarking the performance of our investments against certain indices and by maintaining, and periodically reviewing, target allocation percentages for various asset classes. The accounting for nuclear decommissioning recognizes that the Utilities' regulated electric rates provide for recovery of these costs net of any trust fund earnings, and, therefore, fluctuations in trust fund marketable security returns do not affect earnings. See Note 13 for further information on the trust fund securities.

Contingent Value Obligations Market Value Risk

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, 2009 and 2008, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million and $34 million, respectively. A hypothetical 10 percent increase in the December 31, 2009 market price would result in a $2 million increase in the fair value of the CVOs and a corresponding increase in the CVO liability.

Commodity Price Risk

We are exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, electricity and other energy-related products marketed and purchased as a result of our ownership of energy-related assets. Our exposure to these fluctuations is significantly limited by the cost-based regulation of the Utilities. Each state commission allows electric utilities to recover certain of these costs through various cost-recovery clauses to the extent the respective commission determines that such costs are prudent. Therefore, while there may be a delay in the timing between when these costs are incurred and when these costs are recovered from the ratepayers, changes from year to year have no material impact on operating results. In addition, most of our long-term power sales contracts shift substantially all fuel price risk to the purchaser.

Most of our physical commodity contracts are not derivatives or qualify as normal purchases or sales. Therefore, such contracts are not recorded at fair value.

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, 2009 and 2008, substantially all derivative commodity instrument positions were subject to retail regulatory treatment.

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

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions.

The Utilities have derivative instruments related to their exposure to price fluctuations on fuel oil and natural gas purchases. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Consolidated Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, realized gains or losses are passed through the fuel cost-recovery clause. During the years ended December 31, 2009, 2008 and 2007, we recorded a net realized loss of $659 million, a net realized gain of $174 million and a net realized loss of $55 million, respectively.

Certain of our hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparty negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

At December 31, 2009, the fair value of PEC's commodity derivative instruments was recorded as a $28 million short-term derivative liability position included in derivative liabilities and a $62 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. At December 31, 2008, the fair value of PEC's commodity derivative instruments was recorded as a $45 million short-term derivative liability position included in derivative liabilities and a $54 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. Certain counterparties have held cash collateral in support of these instruments. PEC had a cash collateral asset included in derivative collateral posted of $7 million and $18 million on the Consolidated Balance Sheet at December 31, 2009 and 2008, respectively.

At December 31, 2009, the fair value of PEF's commodity derivative instruments was recorded as an $11 million short-term derivative asset position included in prepayments and other current assets, a $9 million long-term derivative asset position included in other assets and deferred debits, a $161 million short-term derivative liability position included in current derivative liabilities, and a $174 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. At December 31, 2008, the fair value of PEF's commodity derivative instruments was recorded as a $9 million short-term derivative asset position included in prepayments and other current assets, a $1 million long-term derivative asset position included in other assets and deferred debits, a $380 million short-term derivative liability position included in current derivative liabilities, and a $209 million long-term derivative liability position included in derivative liabilities on the Consolidated Balance Sheet. Certain counterparties have held cash collateral in support of these instruments. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted the amount of collateral posted with counterparties. PEF's cash collateral asset included in derivative collateral posted on the Consolidated Balance Sheet was $139 million at December 31, 2009, compared to $335 million at December 31, 2008.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges. From time to time we 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. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. Realized gains and losses are recorded net as part of fleet vehicle costs. At December 31, 2009 and 2008, we had no material outstanding positions in such contracts. The ineffective portion of commodity cash flow hedges was not material to our results of operations for 2009, 2008 and 2007.

At December 31, 2009 and 2008, 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, 2009. Management based this assessment on criteria for effective internal control over financial reporting described in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of Progress Energy's internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit and Corporate Performance Committee (Audit Committee) of the board of directors.

Based on our assessment, management determined that, at December 31, 2009, 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, 2009, as stated in their report.

William D. Johnson

William D. Johnson
Chairman, President and Chief Executive Officer

Mark F. Mulhern

Mark F. Mulhern
Senior Vice President and Chief Financial Officer

February 26, 2010

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, 2009, 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 as of December 31, 2009, 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, 2009, of the Company and our report dated February 26, 2010 expressed an unqualified opinion on those consolidated financial statements.

Deloitte & Touche LLP

Raleigh, North Carolina
February 26, 2010

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) as of December 31, 2009 and 2008, and the related consolidated statements of income, comprehensive income, changes in total equity, and cash flows for each of the three years in the period ended December 31, 2009. 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 Progress Energy, Inc. and its subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, 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 26, 2010, expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Raleigh, North Carolina
February 26, 2010

CONSOLIDATED STATEMENTS OF INCOME

(in millions except per share data) Years ended December 31	2009	2008	2007
Operating revenues	$9,885	$9,167	$9,153
Operating expenses			
Fuel used in electric generation	3,752	3,021	3,145
Purchased power	911	1,299	1,184
Operation and maintenance	1,894	1,820	1,842
Depreciation, amortization and accretion	986	839	905
Taxes other than on income	557	508	501
Other	13	(3)	30
Total operating expenses	8,113	7,484	7,607
Operating income	1,772	1,683	1,546
Other income (expense)			
Interest income	14	24	34
Allowance for equity funds used during construction	124	122	51
Other, net	6	(17)	(7)
Total other income, net	144	129	78
Interest charges			
Interest charges	718	679	605
Allowance for borrowed funds used during construction	(39)	(40)	(17)
Total interest charges, net	679	639	588
Income from continuing operations before income tax	1,237	1,173	1,036
Income tax expense	397	395	334
Income from continuing operations	840	778	702
Discontinued operations, net of tax	(79)	58	(206)
Net income	761	836	496
Net (income) loss attributable to noncontrolling interests, net of tax	(4)	(6)	8
Net income attributable to controlling interests	$757	$830	$504
Average common shares outstanding – basic	279	262	257
Basic and diluted earnings per common share			
Income from continuing operations attributable to controlling interests, net of tax	$2.99	$2.95	$2.70
Discontinued operations attributable to controlling interests, net of tax	(0.28)	0.22	(0.74)
Net income attributable to controlling interests	$2.71	$3.17	$1.96
Dividends declared per common share	$2.480	$2.465	$2.445
Amounts attributable to controlling interests			
Income from continuing operations attributable to controlling interests, net of tax	$836	$773	$693
Discontinued operations attributable to controlling interests, net of tax	(79)	57	(189)
Net income attributable to controlling interests	$757	$830	$504

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(in millions) December 31	2009	2008
ASSETS		
Utility plant		
Utility plant in service	$28,918	$26,326
Accumulated depreciation	(11,576)	(11,298)
Utility plant in service, net	17,342	15,028
Held for future use	47	38
Construction work in progress	1,790	2,745
Nuclear fuel, net of amortization	554	482
Total utility plant, net	19,733	18,293
Current assets		
Cash and cash equivalents	725	180
Receivables, net	800	867
Inventory	1,325	1,239
Regulatory assets	142	533
Derivative collateral posted	146	353
Income taxes receivable	145	194
Prepayments and other current assets	248	154
Total current assets	3,531	3,520
Deferred debits and other assets		
Regulatory assets	2,179	2,567
Nuclear decommissioning trust funds	1,367	1,089
Miscellaneous other property and investments	438	446
Goodwill	3,655	3,655
Other assets and deferred debits	333	303
Total deferred debits and other assets	7,972	8,060
Total assets	$31,236	$29,873
CAPITALIZATION AND LIABILITIES		
Common stock equity		
Common stock without par value, 500 million shares authorized, 281 million and 264 million shares issued and outstanding, respectively	$6,873	$6,206
Unearned ESOP shares (1 million shares)	(12)	(25)
Accumulated other comprehensive loss	(87)	(116)
Retained earnings	2,675	2,622
Total common stock equity	9,449	8,687
Noncontrolling interests	6	6
Total equity	9,455	8,693
Preferred stock of subsidiaries	93	93
Long-term debt, affiliate	272	272
Long-term debt, net	11,779	10,387
Total capitalization	21,599	19,445
Current liabilities		
Current portion of long-term debt	406	–
Short-term debt	140	1,050
Accounts payable	835	912
Interest accrued	206	167
Dividends declared	175	164
Customer deposits	300	282
Derivative liabilities	190	493
Accrued compensation and other benefits	167	193
Other current liabilities	239	225
Total current liabilities	2,658	3,486
Deferred credits and other liabilities		
Noncurrent income tax liabilities	1,196	818
Accumulated deferred investment tax credits	117	127
Regulatory liabilities	2,510	2,181
Asset retirement obligations	1,170	1,471
Accrued pension and other benefits	1,339	1,594
Capital lease obligations	221	231
Derivative liabilities	240	269
Other liabilities and deferred credits	186	251
Total deferred credits and other liabilities	6,979	6,942
Commitments and contingencies (Notes 21 and 22)		
Total capitalization and liabilities	$31,236	$29,873

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions) Years ended December 31	2009	2008	2007
Operating activities			
Net income	$761	$836	$496
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, amortization and accretion	1,135	957	1,026
Deferred income taxes and investment tax credits, net	220	411	177
Deferred fuel cost (credit)	290	(333)	117
Deferred income	–	–	(128)
Allowance for equity funds used during construction	(124)	(122)	(51)
Loss (gain) on sales of assets	2	(75)	(29)
Other adjustments to net income	269	135	212
Cash provided (used) by changes in operating assets and liabilities			
Receivables	25	233	(186)
Inventory	(99)	(237)	(11)
Derivative collateral posted	200	(340)	55
Prepayments and other current assets	3	7	35
Income taxes, net	(14)	(169)	(275)
Accounts payable	(26)	77	(40)
Other current liabilities	(42)	(103)	81
Other assets and deferred debits	11	(44)	(198)
Accrued pension and other benefits	(285)	(39)	(91)
Other liabilities and deferred credits	(56)	24	62
Net cash provided by operating activities	2,271	1,218	1,252
Investing activities			
Gross property additions	(2,295)	(2,333)	(1,973)
Nuclear fuel additions	(200)	(222)	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	1	72	675
Purchases of available-for-sale securities and other investments	(2,350)	(1,590)	(1,413)
Proceeds from available-for-sale securities and other investments	2,314	1,534	1,452
Other investing activities	(2)	(2)	30
Net cash used by investing activities	(2,532)	(2,541)	(1,457)
Financing activities			
Issuance of common stock	623	132	151
Dividends paid on common stock	(693)	(642)	(627)
Payments of short-term debt with original maturities greater than 90 days	(29)	(176)	–
Proceeds from issuance of short-term debt with original maturities greater than 90 days	–	29	176
Net (decrease) increase in short-term debt	(981)	1,096	25
Proceeds from issuance of long-term debt, net	2,278	1,797	739
Retirement of long-term debt	(400)	(877)	(324)
Cash distributions to noncontrolling interests	(6)	(85)	(10)
Other financing activities	14	(26)	65
Net cash provided by financing activities	806	1,248	195
Net increase (decrease) in cash and cash equivalents	545	(75)	(10)
Cash and cash equivalents at beginning of year	180	255	265
Cash and cash equivalents at end of year	$725	$180	$255
Supplemental disclosures			
Cash paid during the year			
Interest, net of amount capitalized	$701	$612	$585
Income taxes, net of refunds	87	152	176
Significant noncash transactions			
Capital lease obligation incurred	–	–	182
Accrued property additions	252	334	329
Asset retirement obligation additions and estimate revisions	(384)	14	–

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN TOTAL EQUITY

(in millions except per share data)	Common Stock Outstanding Shares	Common Stock Outstanding Amount	Unearned ESOP Shares	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Noncontrolling Interests	Total Equity
Balance, December 31, 2006	256	$5,791	$(50)	$(49)	$2,567	$10	$8,269
Net income		–	–	–	504	(8)	496
Other comprehensive income		–	–	15	–	–	15
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 ($2.445 per share)		–	–	–	(631)	–	(631)
Sale of subsidiary shares to noncontrolling interests		–	–	–	–	37	37
Distributions to noncontrolling interests		–	–	–	–	(10)	(10)
Contributions from noncontrolling interests		–	–	–	–	52	52
Other transactions		–	–	–	–	3	3
Balance, December 31, 2007	260	6,028	(37)	(34)	2,438	84	8,479
Net income		–	–	–	830	6	836
Other comprehensive loss		–	–	(82)	–	–	(82)
Issuance of shares	4	131	–	–	–	–	131
Stock options exercised		1	–	–	–	–	1
Allocation of ESOP shares		13	12	–	–	–	25
Stock-based compensation expense		33	–	–	–	–	33
Dividends ($2.465 per share)		–	–	–	(646)	–	(646)
Distributions to noncontrolling interests		–	–	–	–	(85)	(85)
Contributions from noncontrolling interests		–	–	–	–	2	2
Other transactions		–	–	–	–	(1)	(1)
Balance, December 31, 2008	264	6,206	(25)	(116)	2,622	6	8,693
Net income[a]		–	–	–	757	–	757
Other comprehensive income		–	–	29	–	–	29
Issuance of shares	17	623	–	–	–	–	623
Allocation of ESOP shares		8	13	–	–	–	21
Stock-based compensation expense		36	–	–	–	–	36
Dividends ($2.480 per share)		–	–	–	(704)	–	(704)
Distributions to noncontrolling interests		–	–	–	–	(1)	(1)
Other transactions		–	–	–	–	1	1
Balance, December 31, 2009	281	$6,873	$(12)	$(87)	$2,675	$6	$9,455

[a] Consolidated net income of $761 million includes $4 million attributable to preferred shareholders of subsidiaries, which is not a component of total equity and is excluded from the table above.

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions) Years ended December 31	2009	2008	2007
Net income	$761	$836	$496
Other comprehensive income (loss)			
Reclassification adjustments included in net income			
Change in cash flow hedges (net of tax expense of $4, $2 and $3, respectively)	6	3	4
Change in unrecognized items for pension and other postretirement benefits (net of tax expense of $3, $1 and $1, respectively)	4	1	2
Net unrealized gains (losses) on cash flow hedges (net of tax (expense) benefit of $(10), $24 and $8, respectively)	16	(37)	(13)
Net unrecognized items on pension and other postretirement benefits (net of tax (expense) benefit of $(1), $29 and $(16), respectively)	2	(49)	23
Other (net of tax benefit of $-, $1 and $3, respectively)	1	–	(1)
Other comprehensive income (loss)	29	(82)	15
Comprehensive income	790	754	511
Comprehensive (income) loss attributable to noncontrolling interests, net of tax	(4)	(6)	8
Comprehensive income attributable to controlling interests	$786	$748	$519

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 (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable business segment.

PEC is subject to the regulatory 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), including GAAP for regulated operations. The financial statements include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy, and as such their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements.

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

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies, are accounted for under the equity method of accounting. These investments are primarily in limited liability corporations and limited liability partnerships, and the earnings from these investments are recorded on a pre-tax basis. Other investments are stated principally at cost. These equity and cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. See Note 12 for more information about our investments.

Significant intercompany balances and transactions have been eliminated in consolidation except as permitted by GAAP for regulated operations, 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.

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

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

Certain amounts for 2008 and 2007 have been reclassified to conform to the 2009 presentation.

C. Consolidation of Variable Interest Entities

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities (VIEs) for which we are the primary beneficiary. In general, we determine whether we are the primary beneficiary of a VIE through a qualitative analysis of risk that identifies which variable interest holder absorbs the majority of the financial risk and variability of the VIE. In performing this analysis, we consider all relevant facts and circumstances, including: the design and activities of the VIE, the terms of the contracts the VIE has entered into, the nature of the VIE's variable interests issued and how they were negotiated with or marketed to potential investors, and which parties participated significantly in the design or redesign of the entity. If the qualitative analysis is inconclusive, a specific quantitative analysis is performed.

In June 2009, the Financial Accounting Standards Board (FASB) issued new guidance, which makes significant changes to the model for determining who should consolidate a VIE and addresses how often this assessment should be performed. See Note 2 for further discussion regarding the new guidance, which requires all existing arrangements with VIEs to be evaluated, and any impacts of adoption accounted for as a cumulative-effect adjustment. The guidance is effective for us on January 1, 2010. We do not expect the adoption to have a significant impact on our financial position, results of operations and cash flows.

In addition to the following variable interests listed for PEC, Progress Energy, through its subsidiary Progress Fuels Corporation (Progress Fuels), is the primary beneficiary of, and consolidates, Ceredo Synfuel, LLC (Ceredo), a coal-based solid synthetic fuels production facility that qualified for federal tax credits under Section 45K of the Internal Revenue Code (the Code). In March 2007, we disposed of our 100 percent ownership interest in Ceredo to a third-party buyer. Ceredo ceased operations upon expiration of the synthetic fuels tax credit program at the end of 2007. Our variable interests in Ceredo are comprised of an agreement to operate the Ceredo facility on behalf of the buyer through December 2007 and certain legal and tax indemnifications provided to the buyer. We performed a qualitative analysis to determine the primary beneficiary of Ceredo. The primary factors in the analysis were the estimated levels of production of qualifying synthetic fuels in 2007, the final value of the related 2007 synthetic fuels tax credits, the likelihood of a full or partial phase-out of the 2007 synthetic fuels tax credits due to high oil prices, our exposure to certain variable costs under the facility operating agreement and exposure from indemnifications provided to the buyer. There were no changes to our assessment of the primary beneficiary during 2008 or 2009. No financial or other support has been provided to Ceredo during the periods presented. At December 31, 2009, we had no assets and $3 million of liabilities related to tax indemnifications provided to the buyer included in other liabilities and deferred credits on the Consolidated Balance Sheets. The ultimate resolution of the indemnifications could result in adjustments to the gain on disposal in future periods. The creditors of Ceredo do not have recourse to the general credit of Progress Energy. See Note 22C for a general discussion of guarantees. See Note 22D for discussion of recent developments related to legal indemnifications.

VARIABLE INTEREST ENTITIES FOR WHICH PEC IS THE PRIMARY BENEFICIARY

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). PEC's variable interests are debt and equity investments in the two VIEs. PEC performed quantitative analyses to determine the primary beneficiaries of the two VIEs. The primary factors in the analyses were the estimated economic lives of the partnerships and their net cash flow projections, estimates of available tax credits, and the likelihood of default on debt and other commitments. There were no changes to PEC's assessment of the primary beneficiary during 2007 through 2009. No financial or other support has been provided to the VIEs during the periods presented. At December 31, 2009, PEC had assets of $39 million, substantially all of which was reflected in miscellaneous other property and investment, and $15 million in long-term debt, $3 million in other liabilities and deferred credits and $5 million in accounts payable in the PEC Consolidated Balance Sheets related to the two VIEs. The assets of the two VIEs are collateral for, and can only be used to settle, their obligations. The creditors of these VIEs do not have recourse to the general credit of PEC and there are no other arrangements that could expose PEC to losses.

OTHER VARIABLE PEC INTERESTS

PEC has an equity investment in, and consolidates, one limited partnership investment fund that invests in 17 low-income housing partnerships that qualify for federal and state tax credits. The investment fund accounts for the 17 partnerships on the equity method of accounting. PEC also has an interest in one power plant resulting from long-term power purchase contracts. PEC's only significant exposure to variability from the power purchase 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 $46 million, $44 million and $39 million in 2009, 2008 and 2007, 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 investment fund's 17 partnerships and the power plant owner are VIEs 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 provided by GAAP to the 17 partnerships and the power plant. PEC believes that if it is determined to be the primary beneficiary of these entities, the effect of consolidating the power plant and the investment fund consolidating the 17 partnerships 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 counterparties, the impact cannot be determined at this time.

D. Significant Accounting Policies

USE OF ESTIMATES AND ASSUMPTIONS

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

REVENUE RECOGNITION

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

FUEL COST DEFERRALS

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

EXCISE TAXES

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

The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income in the Consolidated Statements of Income for the years ended December 31, 2009, 2008 and 2007, were $333 million, $295 million and $299 million, respectively.

STOCK-BASED COMPENSATION

As discussed in Note 9B, we account for stock-based compensation utilizing the modified prospective transition method per the fair value recognition provisions of GAAP.

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 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 (AROs) are charged to a regulatory liability.

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

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

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

Substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 4A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization rates of utility assets (See Note 7).

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

The North Carolina Clean Smokestacks Act (Clean Smokestacks Act) was enacted in 2002 and froze North Carolina electric utility base rates for a five-year period, which ended in 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. In September 2008, the NCUC approved PEC's request to terminate any further accelerated amortization of its Clean Smokestacks compliance costs (See Note 7B).

ASSET RETIREMENT OBLIGATIONS

AROs are legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability. Accretion expense is included in depreciation, amortization and accretion in the Consolidated Statements of Income.

CASH AND CASH EQUIVALENTS

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

INVENTORY

We account for inventory, including emission allowances, using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. Materials reserves are established for excess and obsolete inventory.

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to GAAP for regulated operations, which allows a regulated company to record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. Accordingly, the Utilities record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 7A). The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

NUCLEAR COST DEFERRALS

PEF accounts for costs incurred in connection with the proposed nuclear expansion in Florida in accordance with FPSC regulations, which establish an alternative cost-recovery mechanism. PEF is allowed to accelerate the recovery of prudently incurred siting, preconstruction costs, AFUDC and incremental operation and maintenance expenses resulting from the siting, licensing, design and construction of a nuclear plant through PEF's capacity cost-recovery clause. Nuclear costs are deemed to be recovered up to the amount of the FPSC-approved projections, and the deferral of unrecovered nuclear costs accrues a carrying charge equal to PEF's approved AFUDC rate. Unrecovered nuclear costs eligible for accelerated recovery are deferred and recorded as regulatory assets in the Consolidated Balance Sheets and are amortized in the period the costs are collected from customers.

GOODWILL AND INTANGIBLE ASSETS

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

UNAMORTIZED DEBT PREMIUMS, DISCOUNTS AND EXPENSES

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

INCOME TAXES

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

DERIVATIVES

GAAP requires that an entity recognize all derivatives as assets or liabilities on the balance sheet and measure those instruments at fair value, unless the derivatives meet the GAAP criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related hedge criteria are met. We have elected not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. Certain economic derivative instruments receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. See Note 17 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies, such as unfavorable results of litigation, when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. We do not accrue an estimate of legal fees when a contingent loss is initially recorded, but rather when the legal services are actually provided.

As discussed in Note 21, we accrue environmental remediation liabilities when the criteria for loss contingencies have been met. We record accruals for probable and estimable costs related to environmental sites on an undiscounted basis. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as additional information develops or circumstances change. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable or on actual receipt of recovery. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

We review the recoverability of long-lived tangible and intangible assets whenever impairment indicators exist. Examples of these indicators include current period losses, combined with a history of losses or a projection of continuing losses, or a significant decrease in the market price of a long-lived asset group. If an impairment indicator exists for assets to be held and used, then the asset group is tested for recoverability by comparing the carrying value to the sum of undiscounted expected future cash flows directly attributable to the asset group. If the asset group is not recoverable through undiscounted cash flows or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

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

2. NEW ACCOUNTING STANDARDS

Effective July 1, 2009, changes to the source of authoritative U.S. GAAP, the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC), are communicated through an Accounting Standards Update (ASU). ASUs will be published for all authoritative U.S. GAAP promulgated by the FASB, regardless of the form in which such guidance may have been issued prior to release of the FASB Codification (e.g., FASB Statements, FASB Staff Positions, etc.).

ASC 810 Consolidations

On January 1, 2009, we implemented ASC 810-10-65, which was previously referred to as Statement of Financial Accounting Standards (SFAS) No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51." ASC 810-10-65 introduces significant changes in the accounting for noncontrolling interests in a partially owned consolidated subsidiary. The adoption of ASC 810-10-65 resulted in a retrospective change in presentation of the financial statements for all periods presented and additional disclosures but did not have a material impact on our financial position or results of operations.

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

ASC 815-10-65 (SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133")

On January 1, 2009, we implemented ASC 815-10-65, which was previously referred to as SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133." ASC 815-10-65 requires entities to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and its related interpretations and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. See Note 17 for information regarding our first quarter 2009 implementation of ASC 815-10-65. The adoption of ASC 815-10-65 did not have a material impact on our financial position or results of operations.

ASC 260-10-45 (FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities")

On January 1, 2009, we implemented ASC 260-10-45, which was previously referred to as FSP EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities." ASC 260-10-45 requires that certain unvested share-based payment awards (e.g., restricted stock) that contain nonforfeitable rights to dividends or dividend equivalents be included in the computation of earnings per share using the two-class method. ASC 260-10-45 requires a retrospective adjustment for all prior-period earnings per share data. The adoption of ASC 260-10-45 did not have a material impact on our financial position, results of operations or earnings per share amounts.

Fair Value Measurement and Disclosures and Other-Than-Temporary Impairments

In April 2009, the FASB issued three FSPs for guidance on accounting for fair value measurement and other-than-temporary impairments.

ASC 820 includes the FSP previously referred to as FSP FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly," and provides guidance on determining fair value when market activity has decreased for an asset or liability. ASC 825-10-50, previously referred to as FSP FAS 107-1 and APB 28-1, "Interim Disclosures About Fair Value of

Financial Instruments," increases the frequency of fair value disclosures required from annually to quarterly.

ASC 320 includes the FSPs previously referred to as FSP FAS 115-2 and FAS 124-2, "Recognition and Presentation of Other-Than-Temporary Impairments," and revises the recognition and reporting requirements for other-than-temporary impairments of debt securities and increases the frequency of disclosures for debt and equity securities. Under ASC 320, if an entity intends to sell an impaired debt security or more likely than not will be required to sell the security before recovery of its amortized cost basis less any current-period credit loss, an other-than-temporary impairment must be recognized currently in earnings equal to the difference between the investment's amortized cost and its fair value at the balance sheet date.

The new guidance in ASC 820, ASC 825 and ASC 320 was effective for us during the three months ended June 30, 2009. The adoption resulted in additional disclosures but did not have a material impact on our financial position or results of operations. See Note 13 for the disclosures resulting from the implementation of this guidance in 2009.

In January 2010, the FASB issued ASU 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," which amends ASC 820 to clarify certain existing disclosure requirements and to require a number of additional disclosures, including amounts and reasons for significant transfers between the three levels of the fair value hierarchy, and presentation of certain information in the reconciliation of recurring Level 3 measurements on a gross basis. ASU 2010-06 was effective for us on January 1, 2010, with certain disclosures effective for periods beginning January 1, 2011. The adoption of ASU 2010-06 will change certain disclosures in the notes to the financial statements, but will have no impact on our financial position or results of operations.

ASC 715-20-65 (FSP FAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets")

In December 2008, the FASB issued ASC 715-20-65, previously referred to as FSP FAS 132R-1, "Employers' Disclosures about Post Retirement Benefit Plan Assets," which requires additional disclosures on the investment allocation decision-making process, the fair value of each major category of plan assets and the inputs and valuation techniques used to remeasure the fair value of plan assets. ASC 715-20-65 was effective for us on December 31, 2009. The adoption of ASC 715-20-65 resulted in additional disclosures, but did not have a material impact on our financial position or results of operations. See Note 16 for the information regarding our implementation of ASC 715-20-65.

ASU 2009-12, "Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)"

In September 2009, the FASB issued ASU 2009-12, "Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)," which provides additional guidance related to measuring the fair value of certain alternative investments, such as interests in hedge funds, private equity funds, real estate funds, venture capital funds, offshore fund vehicles, and funds of funds. ASU 2009-12 allows reporting entities to use net asset value per share to estimate the fair value of certain investments as a practical expedient and requires disclosures by major category of investment about the attributes of the investments. ASU 2009-12 was effective for us on December 31, 2009. The adoption of ASU 2009-12 did not have a material impact on our financial position or results of operations.

3. DIVESTITURES

We completed our business strategy of divesting nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. The information below presents the impacts of the divestitures on net income attributable to controlling interests.

A. Terminals Operations and Synthetic Fuels Businesses

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

Prior to 2008, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 (Section 29) of the Code and as redesignated effective 2006 as Section 45K of the Code (Section 45K and, collectively, Section 29/45K). The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007.

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates. As a result, during the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations, which was net of a previously recorded indemnification liability of $16 million, and $4 million related to other legal and tax contingency adjustments. The ultimate resolution of these matters could result in further adjustments. See Note 22D for additional information. The accompanying consolidated statements of income reflect the abandoned operations of our synthetic fuels businesses as discontinued operations.

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

(in millions)	2009	2008	2007
Revenues	$–	$17	$1,126
(Loss) earnings before income taxes and noncontrolling interest	$(125)	$8	$2
Income tax benefit, including tax credits	47	12	64
(Loss) earnings attributable to noncontrolling interests of Synthetic Fuels	–	(1)	17
Net (loss) earnings from discontinued operations attributable to controlling interests	(78)	19	83
Gain on disposal of discontinued operations, including income tax expense of $7	–	42	–
(Loss) earnings from discontinued operations attributable to controlling interests	$(78)	$61	$83

B. Coal Mining Businesses

On March 7, 2008, we sold the remaining operations of Progress Fuels Corporation, formerly Electric Fuels Corporation (Progress Fuels) subsidiaries engaged in the coal mining business (Coal Mining) for gross cash proceeds of $23 million. Proceeds from the sale were used for general corporate purposes. As a result of the sale, during the year ended December 31, 2008, we recorded an after-tax gain of $7 million on the sale of these assets. During 2009, we recognized a $1 million loss as a result of post-closing adjustments and pre-divestiture contingencies.

The accompanying consolidated financial statements reflect the Coal Mining as discontinued operations. Results of discontinued operations for the coal mining businesses for the years ended December 31 were as follows:

(in millions)	2009	2008	2007
Revenues	$–	$2	$28
Loss before income taxes	$(2)	$(13)	$(17)
Income tax benefit	1	4	6
Net loss from discontinued operations	(1)	(9)	(11)
Gain on disposal of discontinued operations, including income tax expense of $2	–	7	–
Loss from discontinued operations attributable to controlling interests	$(1)	$(2)	$(11)

C. CCO – Georgia Operations

On March 9, 2007, our subsidiary, Progress Energy 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. The sale of the generation assets closed on June 11, 2007, for a net sales price of $615 million. Based on the terms of the final agreement and post-closing adjustments, during the years ended December 31, 2008 and 2007, we incurred an additional $2 million after-tax in losses and reversed $18 million after-tax of a previously recorded impairment, respectively.

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 represented 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 represented 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. During 2008 and 2009, we recognized a $5 million loss and a $1 million gain, respectively, as a result of post-closing adjustments and pre-divestiture contingencies.

The accompanying consolidated financial statements reflect the operations of CCO as discontinued operations. Interest expense was 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 year ended December 31, 2007, was $11 million. Results of discontinued operations for CCO for the years ended December 31 were as follows:

(in millions)	2009	2008	2007
Revenues	$–	$–	$407
Loss before income taxes	$(1)	$(5)	$(449)
Income tax benefit	2	2	166
Net earnings (loss) from discontinued operations	1	(3)	(283)
(Loss) gain on disposal of discontinued operations, including income tax (expense) benefit of $(2) and $7, respectively	–	(2)	18
Earnings (loss) from discontinued operations attributable to controlling interests	$1	$(5)	$(265)

D. Other Diversified Businesses

Also included in discontinued operations are amounts related to adjustments of our prior sales of other diversified businesses, primarily Progress Rail Services Corporation. We completed the sale of Progress Rail Services Corporation during the year ended December 31, 2005. As a result of certain legal, tax and environmental indemnifications provided by Progress Fuels and Progress Energy, we continue to record adjustments to the loss on sale. During the year ended December 31, 2009, we recorded an after-tax loss on disposal of $1 million and after-tax gains of $3 million and $4 million for the years ended December 31, 2008 and 2007, respectively. The ultimate resolution of these matters could result in additional adjustments to the loss on sale in future periods. See general discussion of guarantees at Note 22C.

E. Ceredo Synthetic Fuels Interests

On March 30, 2007, our Progress Fuels subsidiary disposed of its 100 percent ownership interest in Ceredo, a subsidiary that produced and sold 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 were received as we produced and sold qualifying coal-based solid 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 during the year ended December 31, 2007, and a final payment of $5 million during the year ended December 31, 2008. The note had an interest rate equal to the three-month London Inter Bank Offered Rate (LIBOR) rate plus 1%. The estimated fair value of the note at the inception of the transaction was $48 million. Under the terms of the agreement, the purchase price was reduced by $7 million during the year ended December 31, 2008, based on the final value of the 2007 Section 29/45K tax credits.

During the year ended December 31, 2008, we recognized previously deferred gains on disposal of $5 million based on the final value of the 2007 Section 29/45K tax credits. The operations of Ceredo ceased as of December 31, 2007, and are recorded as discontinued operations for all periods presented. See discussion of the abandonment of our synthetic fuels operations at Note 3A.

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 remain the primary beneficiary of Ceredo and continue to consolidate Ceredo in accordance with GAAP for variable interest entities, but record a 100 percent noncontrolling interest.

4. PROPERTY, PLANT AND EQUIPMENT

A. Utility Plant

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

(in millions)	Depreciable Lives	2009	2008
Production plant	7-43	$16,042	$14,117
Transmission plant	17-75	3,273	2,970
Distribution plant	13-55	8,376	8,028
General plant and other	5-35	1,227	1,211
Utility plant in service		$28,918	$26,326

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

AFUDC represents the estimated costs of capital funds necessary to finance the construction of new regulated assets. As prescribed in the regulatory uniform systems of accounts, AFUDC is charged to the cost of the plant for certain projects in accordance with the regulatory provisions for each jurisdiction. The equity funds portion of AFUDC is credited to other income, and the borrowed funds portion is credited to interest charges. Regulatory authorities consider AFUDC an appropriate charge for inclusion in the rates charged to customers by the Utilities over the service life of the property. The composite AFUDC rate for PEC's electric utility plant was 9.2%, 9.2% and 8.8% in 2009, 2008 and 2007, respectively. The composite AFUDC rate for PEF's electric utility plant was 8.8% in 2009, 2008 and 2007.

Our depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4%, 2.3% and 2.4% in 2009, 2008 and 2007, respectively.

The depreciation provisions related to utility plant were $626 million, $578 million and $560 million in 2009, 2008 and 2007, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 4C), regulatory approved expenses (See Notes 7 and 21) and Clean Smokestacks Act amortization (See Note 7B).

Nuclear fuel, net of amortization at December 31, 2009 and 2008, was $554 million and $482 million, respectively. The amount not yet in service at December 31, 2009 and 2008, was $308 million and $243 million, respectively. 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, was $159 million, $145 million and $139 million for the years ended December 31, 2009, 2008 and 2007, respectively. This amortization expense is included in fuel used for electric generation in the Consolidated Statements of Income.

PEF's construction work in progress related to certain nuclear projects has received regulatory treatment. At December 31, 2009, PEF reflected $296 million of construction work in progress, $274 million of which was reflected as a nuclear cost-recovery clause regulatory asset (See Note 7C) and $22 million was reflected as a deferred fuel regulatory asset. At December 31, 2008, PEF reflected $174 million of construction work in progress as a regulatory asset pursuant to accelerated regulatory recovery of nuclear costs (See Note 7C).

B. Joint Ownership of Generating Facilities

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs (See Note 21B). Each of the Utilities' share of operating costs of the jointly owned generating facilities is included within the corresponding line in the Consolidated Statements of Income. The co-owner of Intercession City Unit P11 has exclusive rights to the output of the unit during the months of June through September. PEF has that right for the remainder of the year. PEC's and PEF's ownership interests in the jointly owned generating facilities are listed below with related information at December 31:

2009 *(in millions)* Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$785	$282	$8
PEC	Harris	83.83%	3,207	1,651	28
PEC	Brunswick	81.67%	1,681	981	74
PEC	Roxboro Unit 4	87.06%	686	449	15
PEF	Crystal River Unit 3	91.78%	900	472	510
PEF	Intercession City Unit P11	66.67%	23	10	–

2008 *(in millions)* Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
PEC	Mayo	83.83%	$519	$278	$228
PEC	Harris	83.83%	3,187	1,603	21
PEC	Brunswick	81.67%	1,667	970	42
PEC	Roxboro Unit 4	87.06%	674	446	12
PEF	Crystal River Unit 3	91.78%	843	461	252
PEF	Intercession City Unit P11	66.67%	23	9	–

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.

C. Asset Retirement Obligations

At December 31, 2009 and 2008, our asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant, net of accumulated depreciation, totaled $132 million and $163 million, respectively. The fair value of funds set aside in the Utilities' NDT funds for the nuclear decommissioning liability totaled $1.367 billion and $1.089 billion at December 31, 2009 and 2008, respectively (See Notes 12 and 13). Net NDT unrealized gains are included in regulatory liabilities (See Note 7A).

Our nuclear decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2009, 2008 and 2007. As discussed below, PEF has suspended its accrual for nuclear decommissioning. Management believes that nuclear decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning. Expenses recognized for the disposal or removal of utility assets that do not meet the definition of AROs, which are included in depreciation, amortization and accretion expense, were $141 million, $133 million and $126 million in 2009, 2008 and 2007, respectively.

During 2009, PEF submitted a depreciation study as required by the FPSC no less than every four years. Implementation of the depreciation study is expected to have an insignificant impact on cost of removal expense in 2010.

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)	2009	2008
Removal costs	$1,532	$1,478
Nonirradiated decommissioning costs	211	146
Dismantlement costs	123	124
Non-ARO cost of removal	$1,866	$1,748

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC received a new site-specific estimate of decommissioning costs for Robinson Nuclear Plant (Robinson) Unit No. 2, Brunswick Nuclear Plant (Brunswick) Units No. 1 and No. 2, and Harris Nuclear Plant (Harris) Unit No. 1, in December 2009, which will be filed with the NCUC in the first quarter of 2010. PEC's estimate is based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2009 dollars, were $687 million for Unit No. 2 at Robinson, $591 million for Brunswick Unit No. 1, $585 million for Brunswick Unit No. 2 and $1.126 billion for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. See Note 7D for information about the NRC operating licenses held by PEC. Based on updated cost estimates, in 2009 PEC reduced its asset retirement cost net of accumulated depreciation and its ARO liability by approximately $27 million and $390 million, respectively, resulting in no asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant at December 31, 2009.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF received a new site-specific estimate of decommissioning costs for the Crystal River Unit No. 3 (CR3) in October 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing (See Note 7C). However, the FPSC deferred review of PEF's nuclear decommissioning study from the rate case to be addressed in 2010 in order for FPSC staff to assess PEF's study in combination with other utilities anticipated to submit nuclear decommissioning studies in 2010. PEF will not be required to prepare a new site-specific nuclear decommissioning study in 2010; however, PEF will be required to update the 2008 study with the most currently available escalation rates in 2010. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2008 dollars, is $751 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. See Note 7D for information about the NRC operating license held by PEF for CR3. Based on the 2008 estimate and assumed operating license renewal, PEF increased its asset retirement cost and its ARO liability by approximately $19 million in 2008. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended under the terms of previous base rate settlement agreements. PEF expects to continue this suspension based on its planned 2010 nuclear decommissioning filing. In addition, the wholesale accrual on PEF's reserves for nuclear decommissioning was suspended retroactive to January 2006, following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF received an updated fossil dismantlement study estimate in 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing. PEF's reserve for fossil plant dismantlement was approximately $143 million and $145 million at December 31, 2009 and 2008, including amounts in the ARO liability for asbestos abatement, discussed below. Retail accruals on PEF's reserves for fossil plant dismantlement were previously suspended under the terms of previous base rate settlement agreements.

The Utilities have recognized ARO liabilities related to asbestos abatement costs. The ARO liabilities related to asbestos abatement costs were $54 million and $45 million at December 31, 2009 and 2008, respectively.

Additionally, the Utilities have recognized ARO liabilities related to landfill capping costs. The ARO liabilities related to landfill capping costs were $7 million at December 31, 2009 and 2008. For PEC, closure work related to the landfill commenced in 2009 and should be completed in 2010.

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

The following table presents the changes to the AROs during the years ended December 31, 2009 and 2008. Revisions to prior estimates of the regulated ARO are related to the updated cost estimates for nuclear decommissioning and asbestos described above.

(in millions)	
Asset retirement obligations at January 1, 2008	$1,378
Additions	7
Accretion expense	79
Revisions to prior estimates	7
Asset retirement obligations at December 31, 2008	1,471
Accretion expense	**83**
Revisions to prior estimates	**(384)**
Asset retirement obligations at December 31, 2009	**$1,170**

D. Insurance

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

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under this program, following a 12-week deductible period, for 52 weeks in the amount of $3.5 million per week at Brunswick, Harris and Robinson, and $4.5 million per week at CR3. 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 $28 million with respect to the primary coverage, $40 million with respect to the decontamination, decommissioning and excess property coverage, and $25 million for the incremental replacement power costs coverage, in the event covered losses at insured facilities exceed premiums, reserves, reinsurance and other NEIL resources. Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after an accident and, second, to decontaminate the plant, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above.

Both of the Utilities are insured against public liability for a nuclear incident up to $12.595 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, can be assessed for a portion of any third-party liability claims arising from an accident at any commercial nuclear power plant in the United States. In the event that public liability claims from each insured nuclear incident exceed the primary level of coverage provided by American Nuclear Insurers, each company would be subject to pro rata assessments of up to $117.5 million for each reactor owned for each incident. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $17.5 million per reactor owned per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before August 29, 2013.

Under the NEIL policies, if there were multiple terrorism losses within one year, NEIL would make available one industry aggregate limit of $3.240 billion for noncertified acts, along with any amounts it recovers from reinsurance, government indemnity or other sources up to the limits for each claimant. If terrorism losses occurred beyond the one-year period, a new set of limits and resources would apply.

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

5. RECEIVABLES

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

(in millions)	2009	2008
Trade accounts receivable	$581	$648
Unbilled accounts receivable	193	182
Notes receivable	–	2
Derivatives accounts receivable	2	–
Other receivables	42	53
Allowance for doubtful receivables	(18)	(18)
Total receivables, net	$800	$867

6. INVENTORY

At December 31 inventory was comprised of:

(in millions)	2009	2008
Fuel for production	$667	$614
Materials and supplies	639	588
Emission allowances	18	37
Other	1	–
Total inventory	$1,325	$1,239

Materials and supplies amounts above exclude long-term combustion turbine inventory amounts included in other assets and deferred debits on the Consolidated Balance Sheets of $24 million and $23 million at December 31, 2009 and 2008, respectively.

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits on the Consolidated Balance Sheets of $39 million and $61 million, respectively, at December 31, 2009 and 2008.

7. REGULATORY MATTERS

A. Regulatory Assets and Liabilities

As regulated entities, the Utilities are subject to the provisions of GAAP for regulated operations. Accordingly, the Utilities record certain assets and liabilities resulting from the effects of the ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utilities' ability to continue to meet the criteria for application of GAAP for regulated operations could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that GAAP for regulated operations no longer applies to a separable portion of our operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, such an event would require the Utilities to determine if any impairment to other assets, including utility plant, exists and write down impaired assets to their fair values.

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

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

(in millions)	2009	2008
Deferred fuel cost – current (Notes 7B and 7C)	$105	$335
Nuclear deferral (Note 7C)	37	190
Environmental	–	8
Total current regulatory assets	142	533
Deferred fuel cost – long-term (Note 7B)[a]	62	130
Nuclear deferral (Note 7C)[a]	239	–
Deferred impact of ARO (Note 4C)[b]	99	348
Income taxes recoverable through future rates[b]	264	193
Loss on reacquired debt[c]	35	37
Storm deferral (Note 7C)[d]	10	16
Postretirement benefits (Note 16)[e]	945	1,042
Derivative mark-to-market adjustment (Note 17A)[f]	436	697
Environmental (Notes 7C and 21A)[g]	24	31
Accrued vacation[a]	10	32
DSM/Energy-efficiency deferral (Note 7B)[h]	19	9
Other	36	32
Total long-term regulatory assets	2,179	2,567
Environmental (Note 7C)	(24)	–
Deferred energy conservation cost and other current regulatory liabilities	(3)	(6)
Total current regulatory liabilities	(27)	(6)
Non-ARO cost of removal (Note 4C)[b]	(1,866)	(1,748)
Deferred impact of ARO (Note 4C)[b]	(150)	(198)
Net nuclear decommissioning trust unrealized gains (Note 4C)[i]	(295)	(28)
Derivative mark-to-market adjustment (Note 17A)[f]	(20)	(26)
Storm reserve (Note 7C)[g]	(136)	(129)
Other	(43)	(52)
Total long-term regulatory liabilities	(2,510)	(2,181)
Net regulatory (liabilities) assets	$(216)	$913

The recovery and amortization periods for these regulatory assets and (liabilities) at 2009 are as follows:

[a] Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding five years.

[b] Asset retirement and removal liabilities are recorded and income taxes recoverable through future rates are recovered over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and adjusted following completion of the related activities.

[c] Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 30 years.

[d] Recorded and recovered or amortized as approved by the FERC over a period not exceeding five years.

[e] Recovered and amortized over the remaining service period of employees. In accordance with a 2009 FPSC order, PEF's 2009 deferred pension expense of $34 million will be amortized to the extent that annual pension expense is less than the $27 million allowance provided for in base rates (See Note 7C).

[f] Related to derivative unrealized gains and losses that are recorded as a regulatory liability or asset, respectively, until the contracts are settled. After settlement of the derivatives and the fuel is consumed, the realized gains or losses are passed through the fuel cost-recovery clause.

[g] Recovered as environmental remediation or storm restoration expenses are incurred.

[h] Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding 10 years.

[i] Related to unrealized gains and losses on nuclear decommissioning trust funds that are recorded as a regulatory asset or liability, respectively, until the funds are used to decommission a nuclear plant.

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 of 12.75 percent. In June 2002, the Clean Smokestacks Act was enacted in North Carolina requiring the state's electric utilities to reduce the emissions of nitrogen oxide (NOx) and sulfur dioxide (SO_2) from 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 flexibility in the amount of annual amortization recorded from none up to $174 million per year.

For the years ended December 31, 2008 and 2007, PEC recognized Clean Smokestacks Act amortization of $15 million and $34 million, respectively, and recognized $584 million in cumulative amortization through December 31, 2008. The NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million as the projects are closed to plant in service. As a result of this order, PEC did not amortize $229 million of the original estimated compliance costs for the Clean Smokestacks Act during 2008 and 2009, but will record depreciation over the useful lives of the assets.

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

FUEL COST RECOVERY

On May 7, 2009, PEC filed with the SCPSC for a decrease in the fuel rate charged to its South Carolina ratepayers. On May 28, 2009, PEC jointly filed a settlement agreement with the South Carolina Office of Regulatory Staff and Nucor Steel. Under the terms of the settlement agreement, the parties agreed to PEC's proposed rate reduction of approximately $13 million. On June 19, 2009, the SCPSC approved the settlement agreement. The decrease was effective July 1, 2009, and decreased residential electric bills by $2.08 per 1,000 kilowatt-hours (kWh), or 2.0 percent, for fuel cost recovery. At December 31, 2009, PEC's South Carolina under-recovered deferred fuel balance was $2 million.

On June 4, 2009, and as updated on August 17, 2009, PEC filed with the NCUC for a $14 million decrease in the fuel rate charged to its North Carolina ratepayers, driven by declining fuel prices. On November 16, 2009, the NCUC approved PEC's request. Effective December 1, 2009, residential electric bills decreased by $0.45 per 1,000 kWh, or 0.4 percent, for fuel cost recovery. At December 31, 2009, PEC's North Carolina under-recovered deferred fuel balance was $148 million, $62 million of which is expected to be collected after 2010 and has been classified as a long-term regulatory asset.

DEMAND-SIDE MANAGEMENT AND ENERGY-EFFICIENCY COST RECOVERY

Comprehensive energy legislation enacted by North Carolina in 2007 allows PEC to recover the costs of demand-side management (DSM) and energy-efficiency programs through an annual DSM clause. The law allows PEC to capitalize those costs 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, but are not limited to, any program or initiative that shifts the timing of electricity use from peak to nonpeak periods and includes load management, electricity system and operating controls, direct load control, interruptible load and electric system equipment and operating controls. PEC has implemented a series of DSM and energy-efficiency programs and will continue to pursue additional programs. These programs must be approved by the NCUC, and we cannot predict the outcome of the DSM and energy-efficiency filings currently pending approval by the NCUC or whether the implemented programs will produce the expected operational and economic results. At December 31, 2009, PEC's deferred North Carolina DSM and energy-efficiency costs totaled $15 million.

On June 6, 2008, and as subsequently amended, PEC filed an application with the NCUC for approval of a DSM and energy-efficiency rider to recover all program costs, including the recovery of appropriate incentives for investing in such programs. On November 14, 2008, the NCUC issued an order allowing PEC to implement the rates requested in PEC's November 14, 2008 revision to its initial application. The new rates, subject to true-up to the final order, were implemented on December 1, 2008, increasing residential electrical bills by $0.74 per 1,000 kWh, or 0.8 percent. As a result of settlement agreements entered into in 2007 and resulting regulatory proceedings, the NCUC ordered PEC to recalculate rates and submit to the NCUC for approval. The 2009 impact of these revised rates was immaterial.

On June 4, 2009, and as updated on August 17, 2009, PEC requested the NCUC approve a $1 million increase in the DSM and energy-efficiency rate charged to its North Carolina ratepayers. Due to changes in how the costs are allocated among customer classes, the request results in a decrease to the residential rate, while increasing rates for other customer classes. The rate change was approved on an interim basis effective December 1, 2009, and decreased residential electric bills by $0.19 per 1,000 kWh, or 0.2 percent.

On June 27, 2008, PEC filed an application with the SCPSC to establish procedures that encourage investment in cost-effective energy-efficient technologies and energy conservation programs and approve the establishment of an annual rider to allow recovery for all costs associated with such programs, as well as the recovery of appropriate incentives for investing in such programs. On January 23, 2009, PEC filed a Stipulation Agreement between PEC and some of the other parties to the proceeding. On May 6, 2009, the SCPSC approved the Stipulation Agreement and issued a directive requiring PEC to file for approval of all proposed DSM and energy-efficiency programs. On May 11, 2009, in accordance with the SCPSC directive, PEC filed its programs for approval and an application for a cost-recovery rider for PEC's DSM and energy-efficiency programs. On June 10, 2009, SCPSC approved the proposed DSM and energy-efficiency programs and the cost-recovery rider application, on a provisional basis pending a review of the cost-recovery rider by the South Carolina Office of Regulatory Staff. The rate increase was effective July 1, 2009, and increased residential electric bills by $0.79 per 1,000 kWh, or 0.8 percent, for DSM and energy-efficiency cost recovery. We cannot predict the outcome of this matter. At December 31, 2009, PEC's deferred South Carolina DSM and energy-efficiency costs totaled $4 million.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD COST RECOVERY

Beginning in 2009, PEC is required to file an annual North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) compliance report with the NCUC demonstrating the actions it has taken to comply with the NC REPS requirement. The rules measure compliance with the NC REPS requirement via renewable energy certificates (REC) earned after January 1, 2008. The NCUC has selected APX, Inc. as the vendor for implementation of a statewide REC tracking system. North Carolina electric power suppliers with a renewable energy compliance obligation, including PEC, will participate in the registry. Rates for the NC REPS clause are set based on projected costs with true-up provisions. On June 4, 2009 and as updated August 17, 2009, PEC filed with the NCUC for a $7 million increase in the NC REPS rate charged to its North Carolina ratepayers. On November 12, 2009, the NCUC approved PEC's request effective December 1, 2009. PEC's residential electric bills increased by $0.29 per month, or 0.3 percent, for renewable energy portfolio standard (REPS) cost recovery.

ENVIRONMENTAL COMPLIANCE COST RECOVERY

On February 11, 2009, the SCPSC issued an order allowing PEC to begin deferring as a regulatory asset the depreciation expense that PEC incurs on its environmental compliance control facilities as well as the incremental operation and maintenance expenses that PEC incurs in connection with its environmental compliance control facilities. At December 31, 2009, PEC's South Carolina environmental compliance cost-recovery balance was $5 million.

OTHER MATTERS

The NCUC and the SCPSC approved proposals to accelerate cost recovery of PEC's nuclear generating assets beginning January 1, 2000, and continuing through 2009. The North Carolina aggregate minimum and maximum amounts of cost recovery were $415 million and $585 million, respectively, with flexibility in the amount of annual depreciation recorded, from none to $150 million per year. Accelerated cost recovery of these assets resulted in additional depreciation expense of $52 million and $37 million for the years ended December 31, 2008 and 2007, respectively. PEC reached the minimum amount of $415 million of cost recovery by December 31, 2008, and no additional depreciation expense from accelerated cost recovery was recorded in 2009. The South Carolina aggregate minimum and maximum amounts of cost recovery were $115 million and $165 million, respectively. Prior to the SCPSC's 2008 approval to terminate PEC's remaining obligation to accelerate the cost recovery of PEC's nuclear generating assets, PEC had recorded cumulative accelerated depreciation of $77 million for the South Carolina jurisdiction. As a result of the SCPSC's 2008 approval, PEC will not be required to recognize the remaining $38 million of accelerated depreciation required to reach the minimum amount of cost recovery for the South Carolina jurisdiction, but will record depreciation over the useful lives of the assets. No additional depreciation expense from accelerated cost recovery for the South Carolina jurisdiction was recorded in 2009, 2008 or 2007.

On April 30, 2008, PEC 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-based rates for the PEC OATT in order to more accurately reflect the costs that PEC incurs in providing transmission service. In the filing, PEC proposed to move from a fixed revenue requirement to a formula-based rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. The settlement was approved by FERC and new rates were implemented on July 1, 2008. On May 15, 2009, PEC filed its annual update to the formula-based OATT rates. The new rates were effective June 1, 2009, and increased 2009 revenues by $4 million.

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

North Carolina enacted a law in July 2009 that abbreviates the certification process for a public utility to construct a new natural gas plant as long as the public utility permanently retires the existing coal units at that specific site. On August 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C. PEC projects that the generating facility would be in service by January 2013. PEC proposed that upon completion of the generating facility, it will permanently cease operation of the three coal-fired generating units, with a combined generating capacity of approximately 400 MW, that are currently in operation at the site. This will result in approximately 550 MW of incremental capacity. On September 21, 2009, the Public Staff recommended that the NCUC issue the certificate subject to additional conditions as follows: the facility be constructed and operated in accordance with all applicable laws and regulations, PEC file with the NCUC a progress report and any revisions in the cost estimates on an annual basis, PEC permanently cease operation of the three coal-fired units immediately upon completion and placement into service of the facility and that the NCUC clarify that the issuance of the certificate does not constitute approval of the final costs associated with construction of the facility. On October 1, 2009, the NCUC issued a notice of decision stating it found good cause to issue an order granting PEC the certificate subject to the four conditions proposed by the Public Staff as well as adding a condition that PEC submit for NCUC approval a plan to retire additional coal-fired capacity reasonably proportionate to the 550 MW of incremental capacity. On October 22, 2009, the NCUC issued its order granting PEC the certificate to construct the 950-MW facility.

On December 1, 2009, PEC filed with the NCUC a plan to retire no later than December 31, 2017, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. PEC intends to continue to depreciate these units using the current depreciation rates as on file with the NCUC and the SCPSC until PEC completes and files a new depreciation study.

On December 18, 2009, PEC filed with the NCUC an application for a Certificate of Public Convenience and Necessity to construct a 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C. PEC projects that the generating facility would be in service by late 2013 or early 2014. PEC proposed that upon completion of the generating facility, it will permanently cease operation of the three coal-fired generating units currently in operation at the site that do not have scrubbers. These units have a combined generating capacity of approximately 600 MW.

C. PEF Retail Rate Matters

BASE RATES

As a result of a base rate proceeding in 2005, PEF was party to a base rate settlement agreement that was effective with the first billing cycle of January 2006 and remained in effect through the last billing cycle of December 2009.

On March 20, 2009, in anticipation of the expiration of its current base rate settlement agreement, PEF filed with the FPSC a proposal for an increase in base rates effective January 1, 2010. In its filing, PEF requested the FPSC to approve calendar year 2010 as the projected test period for setting new base rates and approve annual rate relief for PEF of $499 million, which included PEF's petition for a combined $76 million of new base rates in 2009 as discussed below. The request for increased base rates was based, in part, on investments PEF is making in its generating fleet and in its transmission and distribution systems.

Included within the base rate proposal was a request for an interim base rate increase of $13 million. Additionally, on March 20, 2009, PEF petitioned the FPSC for a limited proceeding to include in base rates revenue requirements of $63 million for the repowered Bartow Plant, which began commercial operations in June 2009. On May 19, 2009, the FPSC approved both the annualized interim base rate increase and the cost recovery for the repowered Bartow Plant subject to refund with interest effective July 1, 2009. Based on actual energy sales, the interim and limited base rate relief increased revenues by $79 million during the year ended December 31, 2009. The changes increased residential bills by approximately $4.52 per 1,000 kWh, or 3.7 percent. On July 2, 2009, Florida's Office of Public Counsel (OPC), the Florida Industrial Power Users Group, the attorney general, the Florida Retail Federation and PCS Phosphate filed a petition protesting portions of the FPSC approval. On August 31, 2009, the FPSC issued an order to consolidate the interim and limited base rate relief increase and the base rate proposal. PEF's remaining base rate request as filed by PEF would have increased residential bills by approximately $9.66 per 1,000 kWh, or 7.6 percent, effective January 1, 2010. A hearing was held on this matter September 21, 2009 – October 1, 2009. On October 27, 2009, the FPSC held a hearing to determine if the voting of pending rate cases should be delayed until new FPSC appointees took office in January 2010. During the hearing, the FPSC voted to delay the rulings on the appropriate level of revenue requirements until January 11, 2010.

On January 11, 2010, the FPSC approved a base rate increase of $132 million effective January 1, 2010, which represents the annualized impact of the rate increase that was approved and effective July 2009 for the repowered Bartow Plant. Additionally, the FPSC did not require PEF to refund the 2009 interim base rate increase previously discussed. The difference between PEF's requested $499 million incremental revenues and the $132 million granted by the FPSC is a function of several factors, including, among other things: 1) PEF had proposed rates based on a return on equity of 12.54 percent and the FPSC granted rates based on a return on equity of 10.5 percent; 2) the FPSC granted rates based on projected annual depreciation expense that is approximately $119 million lower than the amount requested by PEF; and 3) the FPSC's ruling incorporates projected annual operating and maintenance (O&M) costs that are approximately $77 million lower than the O&M cost requested by PEF and the elimination of $15 million of annual storm reserve accrual, which represented a $9 million increase over the accrual previously in effect. We are currently reviewing our regulatory options in Florida.

FUEL COST RECOVERY

On March 17, 2009, PEF received approval from the FPSC to reduce its 2009 fuel cost-recovery factors by an amount sufficient to achieve a $206 million reduction in fuel charges to retail customers as a result of effective fuel purchasing strategies and lower fuel prices. The approval reduced residential customers' fuel charges by $6.90 per 1,000 kWh, or 5.0 percent, starting with the first billing cycle of April 2009, with similar reductions for commercial and industrial customers.

On August 10, 2006, Florida's OPC filed a petition with the FPSC asking that the FPSC require PEF to refund to ratepayers alleged excessive past fuel-recovery charges and SO_2 allowance costs during the period 1996 to 2005. 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 October 10, 2007, the FPSC issued its order rejecting most of the OPC's contentions. However, the FPSC 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. The refund was returned to ratepayers in 2008 through a reduction of prior year under-recovered fuel costs. The FPSC also ordered PEF to address whether it was prudent in its 2006 and 2007 coal purchases for Crystal River Units No. 4 and 5 coal-fired steam turbines (CR4 and CR5). On February 2, 2009, the OPC filed direct testimony alleging that during 2006 and 2007, PEF collected excessive fuel costs and SO_2 allowance costs of $61 million before interest. The OPC claimed that these excessive costs were attributed to PEF's ongoing practice of not blending the most economical sources of coal at its CR4 and CR5 plants. During the hearing on the matter, the OPC reduced the alleged excessive fuel costs to $33 million before interest. On June 30, 2009, the FPSC approved a refund of $8 million to PEF's ratepayers to be paid over a 12-month period beginning January 1, 2010, and ordered PEF to file a report by September 2009 regarding the prospective application of PEF's coal procurement plan and the prudence of PEF's coal procurement actions. In compliance with the FPSC order, PEF filed the coal procurement status report on September 14, 2009. For the year ended December 31, 2009, PEF recorded a pre-tax other operating expense of $8 million, an immaterial amount of interest and an associated regulatory liability included within PEF's deferred fuel cost at December 31, 2009. PEF chose not to appeal the FPSC's order.

On September 14, 2009, PEF filed a request with the FPSC to seek approval of a cost adjustment to reduce fuel costs by $105 million, thereby decreasing residential electric bills by $3.34 per 1,000 kWh, or 2.6 percent, effective January 1, 2010. This decrease is due to a decrease of $9.89 per 1,000 kWh for the projected recovery of fuel costs, partially offset by an increase of $6.55 per 1,000 kWh for the projected recovery through the capacity cost-recovery clause (CCRC). The decrease in projected fuel costs is due primarily to a decrease in the price of natural gas and a change in the expected average fuel costs. An extended biennial nuclear outage at CR3 for an uprate project in 2009 contributed to higher projected fuel costs for 2009; however, anticipated changes in the generation mix for 2010 are expected to result in lower average fuel costs and contributed to the projected decrease in 2010 fuel costs. The increase in the CCRC is primarily the result of projected costs to be incurred in 2010 under the nuclear cost-recovery rule discussed below for the proposed nuclear plant in Levy County, Fla. (Levy) and an under-recovery of purchased power costs in 2009. On October 23, 2009, as a result of the October 16, 2009 FPSC vote in the nuclear cost-recovery matter discussed more fully below, PEF filed a $3 million cost adjustment with the FPSC, which reduced the CCRC rate by $0.08 per 1,000 kWh from the original September 14, 2009 cost-adjustment filing. The FPSC approved PEF's fuel and capacity clause filings on November 2, 2009, to be effective January 1, 2010.

On August 28, 2009, PEF filed a request to increase the Environmental Cost Recovery Clause (ECRC) residential rate and the filing was updated on October 27, 2009. PEF is asking the FPSC to increase residential rates by $2.25 per 1,000 kWh, or 1.8 percent. This would increase projected revenues by $33 million. This increase is primarily due to the return on assets expected to be placed in service at the end of 2009. On September 14, 2009, PEF filed a request to increase the Energy Conservation Cost Recovery Clause (ECCR) residential rate by $0.47 per 1,000 kWh, or 0.4 percent. This would increase projected revenues by $4 million. This increase is due mainly to an increase in conservation program costs. The FPSC approved PEF's ECRC and ECCR clause filings on November 2, 2009, to be effective January 1, 2010.

NUCLEAR COST RECOVERY

Levy Nuclear

On March 11, 2008, PEF filed a petition for an affirmative Determination of Need for its proposed Levy Units 1 and 2 nuclear power plants, together with the associated facilities, including transmission lines and substation facilities. Levy Units 1 and 2 are needed to maintain electric system reliability and integrity, fuel and generating diversity and to continue to provide adequate electricity to PEF's customers at a reasonable cost. Levy Units 1 and 2 will be advanced passive light water nuclear reactors, each with a generating capacity of approximately 1,100 MW. The petition included projections that Levy Unit 1 would be placed in service by June 2016 and Levy Unit 2 by June 2017. The filed, nonbinding project cost estimate for Levy Units 1 and 2 was approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities. The FPSC issued the final order granting the petition for the Determination of Need for the proposed nuclear units on August 12, 2008.

On March 11, 2008, PEF also filed a petition with the FPSC to open a discovery docket regarding the actual and projected costs of Levy. PEF filed the petition to assist the FPSC in the timely and adequate review of the proposed project's costs recoverable under the nuclear cost-recovery rule. On May 1, 2008, PEF filed a petition for recovery of both preconstruction and carrying charges on construction costs incurred or anticipated to be incurred during 2008 and 2009 under the nuclear cost-recovery rule. Based on the affirmative vote by the FPSC on the Determination of Need for Levy, PEF filed a petition on July 18, 2008, to recover all prudently incurred costs under the nuclear cost-recovery rule. On November 12, 2008, the FPSC issued an order to approve the inclusion of preconstruction and carrying charges of $357 million as well as site selection costs of $38 million in establishing PEF's 2009 capacity cost-recovery clause factor.

On March 17, 2009, PEF received approval from the FPSC to defer until 2010 the recovery of $198 million of nuclear preconstruction costs for Levy, which the FPSC had authorized to be collected in 2009. The approval reduced residential customers' nuclear cost-recovery charge by $7.80 per 1,000 kWh, or 5.7 percent, starting with the first billing cycle of April 2009, with similar reductions for commercial and industrial customers.

On May 1, 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consists of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. This alternate proposal reduced the 2010 revenue requirement to $236 million. On September 14, 2009, consistent with FPSC rules, PEF included both proposed revenue requirements in its CCRC filing, which would result in a nuclear cost-recovery charge of either $7.98 per 1,000 kWh for residential customers under PEF's alternate proposal, or $15.07 per 1,000 kWh if the FPSC did not approve PEF's alternate proposal. At a special agenda hearing by the FPSC on October 16, 2009, the FPSC approved the alternate proposal allowing PEF to recover $207 million of revenue requirements associated with the nuclear cost-recovery clause through the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. This revenue level results in a nuclear cost-recovery charge of $6.99 per 1,000 kWh, which represents a $2.68 increase per 1,000 kWh for residential customer bills. In adopting PEF's proposed rate management plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts.

On October 16, 2009, the FPSC clarified certain implementation policies related to the recognition of deferrals and the application of carrying charges under the nuclear cost-recovery rule. Specifically, the FPSC clarified that (1) nuclear costs are deemed to be recovered up to the amount of FPSC-approved projections and (2) the deferral of unrecovered nuclear costs would accrue a carrying charge at PEF's approved AFUDC rate consistent with the requirements of FPSC's nuclear cost-recovery rule, which is fixed at the pre-tax AFUDC rate in effect as of June 12, 2007. Accordingly, PEF retrospectively assigned capacity revenues to match the FPSC-approved projected level of nuclear cost recovery as of September 30, 2009. Nuclear costs incurred in excess of original projections earn a carrying charge equal to the AFUDC rate. Prior to the FPSC clarification, PEF assigned capacity revenues to nuclear cost recovery based on actual costs incurred; any over- or under-recoveries of actual costs were deferred and earned a carrying charge equal to a commercial paper rate.

On November 19, 2009, the FPSC issued a final order approving the recovery of prudently incurred nuclear costs as a part of PEF's proposed rate management plan. The rate management plan includes the reclassification to the nuclear cost-recovery clause regulatory asset of the 1) $198 million of capacity revenues and 2) the accelerated amortization of $76 million of preconstruction costs. The cumulative amount of $274 million was recorded as a nuclear cost-recovery regulatory asset at December 31, 2009, and is projected to be recovered by 2014.

The FPSC has authorized alternative cost-recovery mechanisms for preconstruction and construction carrying costs of nuclear power plants. Accordingly, at December 31, 2009 and 2008, PEF reflected $276 million and $190 million, respectively, of nuclear-related costs as a regulatory asset, of which $274 million and $174 million, respectively, represents construction work in progress (See Note 4A). Of the total $276 million of nuclear-related costs at December 31, 2009, $275 million related to Levy. The total $190 million of nuclear-related costs at December 31, 2008, was comprised of $181 million related to Levy and $9 million related to the CR3 uprate.

CR3 Uprate

On August 28, 2009, PEF filed a petition with the FPSC to approve a $17 million base rate increase for the phase II costs associated with the uprate of CR3. PEF's 2009 revenue requirements for recovery of the phase II costs were included in the CCRC. As permitted under the nuclear cost-recovery rule, PEF's phase III costs associated with the CR3 uprate are currently being recovered through the CCRC discussed above. On October 29, 2009, the FPSC Staff recommended that the FPSC approve PEF's request with minor modifications and that the new rates be implemented at the same time as PEF implements new base rates from its rate case proceeding. On October 30, 2009, PEF filed an amended petition requesting this rate change be implemented effective January 1, 2010. On December 1, 2009, the FPSC approved an increase in base rates for residential customers by $0.57 per 1,000 kWh, or 0.4 percent.

STORM COST RECOVERY

In 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 four hurricanes in 2004. The net impact was included in customer bills beginning January 1, 2006. In 2007, PEF recorded the remaining amortization of $75 million associated with the recovery of these storm costs.

During 2006, the FPSC approved a settlement agreement between PEF and 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 that began August 2007 to replenish its storm reserve. Additionally, the settlement agreement provided 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. In 2008, PEF recorded net additional storm reserve of $66 million from the extension of the storm surcharge. The surcharge agreement expired in August 2008. At December 31, 2009 and 2008, PEF's storm reserve totaled $136 million and $129 million, respectively.

OTHER MATTERS

On October 29, 2007, PEF submitted a revised OATT filing, including a settlement agreement, with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula-based 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-based rate, which allows for transmission rates to be updated each year based on the prior year's actual costs. The settlement was approved by FERC and new rates were implemented on January 1, 2008. On May 15, 2009, PEF filed its annual update to the formula-based OATT rates. The new rates were effective June 1, 2009, and increased 2009 revenues by $2 million. In addition, one of PEF's large wholesale customers became subject to the new rate structure on September 1, 2009, increasing PEF's 2009 revenues by an additional $4 million.

On March 20, 2009, PEF filed a petition with the FPSC for expedited approval of the deferral of $53 million in 2009 pension expense and the authorization to charge $33 million in estimated 2009 storm hardening expenses to its storm damage reserve. PEF requested that the deferral of pension expense continue until the recovery of these costs is provided for in FPSC-approved base rates. On June 16, 2009, the FPSC denied PEF's request related to the storm hardening expenses, but approved the deferral of the retail portion of actual 2009 pension expense. As a result of the order, PEF deferred pension expense of $34 million for the year ended December 31, 2009. PEF will not earn a carrying charge on the deferred pension regulatory asset. The deferral of pension expense will not result in a change in PEF's 2009 retail rates or prices. In accordance with the order, subsequent to 2009 PEF will amortize the deferred pension regulatory asset to the extent that annual pension expense is less than the $27 million allowance provided for in the base rates established in the 2010 base rate proceeding. In the event such amortization is insufficient to fully amortize the regulatory asset, PEF can seek recovery of the remaining unamortized amount in a base rate proceeding no earlier than 2015.

D. Nuclear License Renewals

PEC's nuclear units are currently operating under licenses that expire between 2010 and 2026. The NRC has granted PEC 20-year renewals of the licenses for its nuclear units, which extend the operating licenses to expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. On December 18, 2008, PEF filed an application for a 20-year renewal from the NRC on the operating license for CR3, which would extend the operating license through 2036, if approved. PEF anticipates a decision from the NRC in 2011.

8. GOODWILL

Goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility segments and our goodwill impairment tests are performed at the utility segment level. At December 31, 2009 and 2008, our carrying amount of goodwill was $3.655 billion, with $1.922 billion assigned to PEC and $1.733 billion assigned to PEF. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment. We perform our annual impairment test as of April 1 of each year. During the second quarter in 2009, we completed the 2009 annual tests, which indicated the goodwill was not impaired.

9. EQUITY

A. Common Stock

At December 31, 2009 and 2008, we had 500 million shares of common stock authorized under our charter, of which 281 million shares and 264 million shares, respectively, were outstanding. For the years ended December 31, 2009, 2008 and 2007, we issued shares of common stock, primarily under a public offering and to meet the requirements of the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)) and the Progress Energy Investor Plus Plan (IPP). In addition, we periodically issue shares for our other benefit plans.

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

	2009		2008		2007	
(in millions)	**Shares**	**Net Proceeds**	Shares	Net Proceeds	Shares	Net Proceeds
Total issuances	17.5	$623	3.7	$132	3.7	$151
Issuances under a public offering	14.4	523	–	–	–	–
Issuances to meet requirements of 401(k) and IPP	2.5	100	3.1	131	1.0	46

The shares issued under a public offering were issued on January 12, 2009, at a public offering price of $37.50. We used $100 million of the proceeds to reduce the Parent's revolving credit agreement (RCA) borrowings and the remainder was used for general corporate purposes.

Subsequent to December 31, 2009, the Parent issued approximately 3.6 million shares of common stock resulting in approximately $136 million in proceeds through the IPP. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2009, there were no significant restrictions on the use of retained earnings (See Note 11B).

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, 2009 and 2008, participating subsidiaries were PEC, PEF, PVI, Progress Fuels (corporate employees) and PESC. The 401(k), which has a matching feature, encourages systematic savings by employees and provides a method of acquiring Progress Energy common stock and other diverse investments. The 401(k), as amended in 1989, is an Employee Stock Ownership Plan (ESOP) that can enter into acquisition loans to acquire Progress Energy common stock to satisfy 401(k) common share needs. Qualification as an ESOP did not change the level of benefits received by employees under the 401(k). Common stock acquired with the proceeds of an ESOP loan 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 0.5 million and 1.1 million ESOP suspense shares at December 31, 2009 and 2008, respectively, with a fair value of $22 million and $45 million, respectively. ESOP shares allocated to plan participants totaled 13.0 million and 12.6 million at December 31, 2009 and 2008, respectively. Our matching compensation cost under the 401(k) is determined based on matching percentages 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 the matching component are typically met with shares in the same year incurred. Matching costs, which were met and will be met with shares released from the suspense account, totaled approximately $13 million, $8 million and $23 million for the years ended December 31, 2009, 2008 and 2007, 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.

We also sponsor the Savings Plan for Employees of Florida Progress Corporation, which covers bargaining unit employees of PEF.

Total matching cost for both plans was approximately $41 million, $38 million and $34 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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 officers and 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, 2009, 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	1.6	$43.99
Canceled	(0.1)	43.76
Exercised	–	–
Options outstanding, December 31	1.5	44.00
Options exercisable, December 31	1.5	44.00

The options outstanding and exercisable at December 31, 2009, had a weighted-average remaining contractual life of 3.03 years. Aggregate intrinsic value as of December 31, 2009, was not significant. The total intrinsic value of options exercised during the years ended December 31, 2009 and 2008, was not significant. Total intrinsic value of options exercised during the year ended December 31, 2007, was $17 million.

Compensation cost for expense purposes is measured at the grant date based on the fair value of the award and is recognized over the vesting period. All options are fully vested; therefore, no compensation expense was recognized in 2009, 2008 or 2007.

Cash received from the exercise of stock options totaled $105 million during the year ended December 31, 2007. The actual tax benefit for tax deductions from stock option exercises for the year ended December 31, 2007, was $6 million. Cash received from the exercise of stock options for the years ended December 31, 2009 and 2008, 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 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. In 2009, the PSSP was redesigned again, and shares issued under the revised plan use total shareholder return and earnings growth as two equally weighted performance measures. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. 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. We issue new shares of common stock to satisfy the requirements of the PSSP program. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with subsequent adjustments made to reflect the status of the performance measure. Compensation expense for all awards is reduced by estimated forfeitures. PSSP cash-settled liabilities paid in the years ended December 31, 2009, 2008 and 2007, were not significant.

A summary of the status of the target performance shares under the stock-settled PSSP plan at December 31, 2009, 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	1,118,604	$46.46
Granted	328,369	33.80
Vested	(419,366)	44.23
Paid[b]	(232,793)	50.55
Forfeited	(16,484)	44.27
Ending balance	778,330	45.49

[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.

For the years ended December 31, 2008 and 2007, the weighted-average grant date fair value of stock-settled performance shares granted was $42.41 and $50.70, respectively.

The Restricted Stock Award 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 included as shares outstanding in the basic earnings per share calculation.

A summary of the status of the nonvested restricted stock shares at December 31, 2009, and changes during the year then ended, follows:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	192,101	$43.93
Granted	–	–
Vested	(50,297)	44.06
Forfeited	(6,500)	42.79
Ending balance	135,304	43.94

For the year ended December 31, 2007, the weighted-average grant date fair value of restricted stock granted was $49.54. There were no restricted stock shares granted in 2008.

The total fair value of restricted stock awards vested during the years ended December 31, 2009, 2008 and 2007, was $2 million, $3 million and $13 million, respectively. No cash was expended to purchase shares for 2009, and cash expended to purchase shares during 2008 and 2007 was not significant due to the curtailment of the Restricted Stock Award program upon the rollout of the restricted stock unit (RSU) program in 2007.

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. We issue new shares of common stock to satisfy the requirements of the RSU program. Compensation expense, based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. RSUs are included as shares outstanding in the basic earnings per share calculation. Units are converted to shares upon vesting.

A summary of the status of nonvested RSUs at December 31, 2009, and changes during the year then ended, follows:

	Number of Restricted Shares	Weighted-Average Grant Date Fair Value
Beginning balance	1,076,536	$46.86
Granted	644,231	33.91
Vested	(342,723)	47.18
Forfeited	(39,759)	41.54
Ending balance	1,338,285	43.46

The total fair value of RSUs vested during the year ended December 31, 2009, was $16 million. No cash was expended to purchase stock to satisfy RSU plan obligations in 2009, 2008 and 2007.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $39 million for the year ended December 31, 2009, with a recognized tax benefit of $15 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $31 million, with a recognized tax benefit of $12 million, and $64 million, with a recognized tax benefit of $24 million, for the years ended December 31, 2008 and 2007, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2009, there was $31 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 1.56 years.

C. Earnings Per Common Share

Basic earnings per common share are based on the weighted-average number of common shares outstanding, which includes the effects of unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents. Diluted earnings per share include the effects of the nonvested portion of performance share awards and the effect of stock options outstanding.

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

(in millions)	2009	2008	2007
Weighted-average common shares – basic	279.4	261.6	257.3
Net effect of dilutive stock-based compensation plans	0.1	0.1	0.2
Weighted-average shares – fully diluted	279.5	261.7	257.5

There were no adjustments to net income or to income from continuing operations attributable to controlling interests between the calculations of basic and fully diluted earnings per common share. 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 ESOP shares totaled 0.7 million, 1.2 million and 1.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. There were 1.5 million, 1.6 million and 0.1 million stock options outstanding at December 31, 2009, 2008 and 2007, 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) Income

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

(in millions)	2009	2008
(Loss) gain on cash flow hedges	$(35)	$(57)
Pension and other postretirement benefits	(52)	(58)
Other	–	(1)
Total accumulated other comprehensive (loss) income	$(87)	$(116)

10. PREFERRED STOCK OF SUBSIDIARIES

All of our preferred stock was issued by the Utilities. The preferred stock is considered temporary equity due to certain provisions that could require us to redeem the preferred stock for cash. In the event dividends payable on PEC or PEF preferred stock are in default an amount equivalent to or exceeding four quarterly dividends payments, the holders of the preferred stock are entitled to elect a majority of PEC's or PEF's respective board of directors until all accrued and unpaid dividends are paid. All classes of preferred stock are entitled to cumulative dividends with preference to the common stock dividends, are redeemable by vote of the Utilities' respective board of directors at any time, and do not have any preemptive rights. All classes of preferred stock have a liquidation preference equal to $100 per share plus any accumulated unpaid dividends except for PEF's 4.75%, $100 par value class, which does not have a liquidation preference. Each holder of PEC's preferred stock is entitled to one vote. The holders of PEF's preferred stock have no right to vote except for certain circumstances involving dividends payable on preferred stock that are in default or certain matters affecting the rights and preferences of the preferred stock.

At December 31, 2009 and 2008, 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

11. DEBT AND CREDIT FACILITIES

A. Debt and Credit Facilities

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2009):

(in millions)		2009	2008
Parent			
Senior unsecured notes, maturing 2010-2039	6.50%	$4,300	$2,600
Draws on revolving credit agreement, expiring 2012		–	100
Unamortized premium and discount, net		(7)	(4)
Current portion of long-term debt		(100)	–
Long-term debt, net		4,193	2,696
PEC			
First mortgage bonds, maturing 2010-2038	5.60%	2,525	2,325
Pollution control obligations, maturing 2017-2024	0.80%	669	669
Senior unsecured notes, maturing 2012	6.50%	500	500
Miscellaneous notes	6.01%	21	22
Unamortized premium and discount, net		(6)	(7)
Current portion of long-term debt		(6)	–
Long-term debt, net		3,703	3,509
PEF			
First mortgage bonds, maturing 2010-2038	5.81%	3,800	3,800
Pollution control obligations, maturing 2018-2027	0.47%	241	241
Medium-term notes, maturing 2028	6.75%	150	150
Unamortized premium and discount, net		(8)	(9)
Current portion of long-term debt		(300)	–
Long-term debt, net		3,883	4,182
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10%	309	309
Unamortized premium and discount, net		(37)	(37)
Long-term debt, net		272	272
Progress Energy consolidated long-term debt, net		$12,051	$10,659

On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with proceeds from the $950 million of Senior Notes issued in November 2009.

On January 12, 2009, the Parent issued 14.4 million shares of common stock at a public offering price of $37.50 per share. Net proceeds from this offering were $523 million. We used $100 million of the proceeds to reduce the Parent's RCA borrowings and the remainder was used for general corporate purposes.

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

On March 19, 2009, the Parent issued an aggregate $750 million of Senior Notes consisting of $300 million of 6.05% Senior Notes due 2014 and $450 million of 7.05% Senior Notes due 2019. A portion of the proceeds was used to fund PEF's capital expenditures through an equity contribution with the remaining proceeds used for general corporate purposes.

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

On November 19, 2009, the Parent issued an aggregate $950 million of Senior Notes consisting of $350 million of 4.875% Senior Notes due 2019 and $600 million of 6.00% Senior Notes due 2039. The proceeds were used to retire at maturity the $100 million outstanding Series A Floating Rate Notes due January 15, 2010, to repay outstanding commercial paper balances, to prefund a portion of the $700 million aggregate principal amount due upon maturity of our 7.10% Senior Notes due March 1, 2011, and for general corporate purposes.

At December 31, 2009 and 2008, we had committed lines of credit used to support our commercial paper borrowings. At December 31, 2009, we had no outstanding borrowings under our credit facilities. At December 31, 2008, we had $600 million of outstanding borrowings under our credit facilities as shown in the following table, $100 million of which was classified as long-term debt. We are required to pay minimal annual commitment fees to maintain our credit facilities.

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

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/Watch Negative by Moody's Investors Service, Inc. (Moody's) and BBB/Watch Negative by Standard & Poor's Rating Service (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+/Watch Negative 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/Watch Negative by Moody's and BBB+/Watch Negative by S&P.

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

(in millions)	2009		2008	
Parent	0.49%	$140	2.81%	$569
PEC	–	–	4.36%	110
PEF	–	–	4.41%	371
Total	0.49%	$140	3.54%	$1,050

(in millions)	Description	Total	Outstanding[a]	Reserved[b]	Available
2009					
Parent	**Five-year (expiring 5/3/12)**	**$1,130**	**$–**	**$177**	**$953**
PEC	**Five-year (expiring 6/28/11)**	**450**	**–**	**–**	**450**
PEF	**Five-year (expiring 3/28/11)**	**450**	**–**	**–**	**450**
Total credit facilities		**$2,030**	**$–**	**$177**	**$1,853**
2008					
Parent	Five-year (expiring 5/3/12)	$1,130	$600	$99	$431
PEC	Five-year (expiring 6/28/11)	450	–	110	340
PEF	Five-year (expiring 3/28/11)	450	–	371	79
Total credit facilities		$2,030	$600	$580	$850

[a] The RCA borrowings outstanding at December 31, 2008, were repaid during 2009.

[b] To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2009 and 2008, the Parent had $37 million and $30 million, respectively, of letters of credit issued, which were supported by the RCA. Subsequent to December 31, 2009, the Parent repaid all of its outstanding commercial paper balance with proceeds from the $950 million November 2009 issuance of Senior Notes.

The following table presents the aggregate maturities of long-term debt at December 31, 2009:

(in millions)	
2010	$406
2011	1,000
2012	950
2013	825
2014	300
Thereafter	9,034
Total	$12,515

B. Covenants and Default Provisions

FINANCIAL COVENANTS

The Parent's, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capital ratio (leverage). At December 31, 2009, the maximum and calculated ratios, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[a]
Parent	68%	58%
PEC	65%	44%
PEF	65%	51%

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

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of the following thresholds: $50 million for the Parent and $35 million each for PEC and PEF. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of their respective cross-default threshold, the lenders of that credit facility could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. The Parent's cross-default provision can be triggered by the Parent and its significant subsidiaries, as defined in the credit agreement. PEC's and PEF's cross-default provisions can be triggered only by defaults of indebtedness by PEC and its subsidiaries and PEF, respectively, not each other or other affiliates of PEC and PEF.

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

OTHER RESTRICTIONS

Neither the Parent's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. At December 31, 2009, the Parent had no shares of preferred stock outstanding.

Certain documents restrict the payment of dividends by the Parent's subsidiaries as outlined below.

PEC's mortgage indenture provides that, as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million, less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2009, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2009, PEC's common stock equity was approximately 55.3 percent of total capitalization. At December 31, 2009, 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, 2009, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, no cash dividends or distributions on common stock shall be paid, if the aggregate amount thereof since April 30, 1944, including the amount then proposed to be expended, plus all other charges to retained earnings since April 30, 1944, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2009, PEF's common stock equity was approximately 53.4 percent of total capitalization. At December 31, 2009, 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, 2009, PEC and PEF had a total of \$3.194 billion and \$4.041 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations. Each mortgage allows the issuance of additional mortgage bonds upon the satisfaction of certain conditions.

D. Guarantees of Subsidiary Debt

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

E. Hedging Activities

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

12. INVESTMENTS

A. Investments

At December 31, 2009 and 2008, 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)	2009	2008
Nuclear decommissioning trust (See Notes 4C and 13)	\$1,367	\$1,089
Equity method investments[a]	18	22
Cost investments[b]	5	7
Company-owned life insurance[c]	45	49
Benefit investment trusts[d]	191	184
Marketable debt securities	–	1
Total	\$1,626	\$1,352

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

[b] Investments stated principally at cost are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

[c] Investments in company-owned life insurance approximate fair value due to the nature of the investment and are included in miscellaneous other property and investments in the Consolidated Balance Sheets.

[d] Benefit investment trusts are included in miscellaneous other property and investments in the Consolidated Balance Sheets. At December 31, 2009 and 2008, \$152 million and \$142 million, respectively, of investments in company-owned life insurance were held in Progress Energy's trusts.

B. Impairment of Investments

We evaluate declines in value of investments under the criteria of GAAP. Declines in fair value to below the cost basis judged to be other than temporary on available-for-sale securities are included in long-term regulatory liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the Consolidated Statements of Income for securities in our benefit investment trusts, other available-for-sale securities and equity and cost method investments. See Note 13 for additional information. There were no material other-than-temporary impairments in 2009, 2008 or 2007.

13. FAIR VALUE DISCLOSURES

A. Debt and Investments

DEBT

The carrying amount of our long-term debt, including current maturities, was \$12.457 billion and \$10.659 billion at December 31, 2009 and 2008, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $13.4 billion and $11.3 billion at December 31, 2009 and 2008, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. Our available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning the Utilities' nuclear plants (See Note 4C). NDT funds are presented on the Consolidated Balance Sheets at fair value. In addition to the NDT funds, we hold other debt investments classified as available-for-sale, which are included in miscellaneous other property and investments on the Consolidated Balance Sheets at fair value.

The following table summarizes our available-for-sale securities at December 31, 2009 and 2008.

(in millions)	Unrealized Losses	Unrealized Gains	Estimated Fair Value
2009			
Equity securities	$(22)	$306	$855
Corporate debt securities	(1)	5	71
U.S. state and municipal debt securities	(2)	3	118
U.S. and foreign government debt securities	(1)	8	197
Money market funds and other securities	–	–	161
Total	$(26)	$322	$1,402
2008			
Equity securities	$(93)	$134	$559
Corporate debt securities	(5)	–	53
U.S. state and municipal debt securities	(19)	4	233
U.S. and foreign government debt securities	(2)	11	171
Money market funds and other securities	(1)	–	123
Total	$(120)	$149	$1,139

The NDT funds and other available-for-sale debt investments held in certain benefit trusts are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities (See Note 7A) pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments; all of the unrealized losses and unrealized gains for 2009, and $118 million of the unrealized losses and $148 million of the unrealized gains for 2008, relate to the NDT funds. There were no material unrealized losses for the other available-for-sale debt securities held in benefit trusts at December 31, 2009 and 2008.

The aggregate fair value of investments that related to the 2009 and 2008 unrealized losses was $209 million and $374 million, respectively.

At December 31, 2009, the fair value of available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$12
Due after one through five years	180
Due after five through 10 years	122
Due after 10 years	84
Total	$398

The following table presents selected information about our sales of available-for-sale securities during the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	2009	2008	2007
Proceeds	$1,275	$1,092	$1,334
Realized gains	26	29	35
Realized losses	87	86	23

Previously, we invested available cash balances in various financial instruments, such as tax-exempt debt securities. For the year ended December 31, 2007, our proceeds from the sale of these securities were $399 million. For the years ended December 31, 2009 and 2008, our proceeds were primarily related to nuclear decommissioning trusts. Some of our benefit investment trusts are managed by third-party investment managers who have the right to sell securities without our authorization. Losses at December 31, 2009, 2008 and 2007 for investments in these benefit investment trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary (See Note 1D). At December 31, 2009 and 2008, our other securities had no investments in a continuous loss position for greater than 12 months.

B. Fair Value Measurements

GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Fair value measurements require the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data, or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs. A midmarket pricing convention (the midpoint price between bid and ask prices) is permitted for use as a practical expedient.

GAAP also establishes a fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

Level 1 – The pricing inputs are unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities.

Level 2 – The pricing inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 2 includes financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives, such as over-the-counter forwards, swaps and options; certain marketable debt securities; and financial instruments traded in less than active markets.

Level 3 – The pricing inputs include significant inputs generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments may include longer-term instruments that extend into periods where quoted prices or other observable inputs are not available.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Nuclear decommissioning trust funds				
Equity	$855	$–	$–	$855
Corporate debt	–	71	–	71
U.S. state and municipal debt	–	117	–	117
U.S. and foreign government debt	62	128	–	190
Money market funds and other	1	133	–	134
Total nuclear decommissioning trust funds	918	449	–	1,367
Commodity and interest rate derivatives	–	39	–	39
Other marketable securities				
U.S. state and municipal debt	–	1	–	1
U.S. and foreign government debt	–	7	–	7
Money market funds and other	16	27	–	43
Total assets	$934	$523	$–	$1,457
Liabilities				
Commodity and interest rate derivatives	$–	$(386)	$(39)	$(425)
CVO derivatives	–	(15)	–	(15)
Total liabilities	$–	$(401)	$(39)	$(440)

The determination of the fair values above incorporates various factors, including risks of nonperformance by us or our counterparties. Such risks consider not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits or letters of credit), but also the impact of our credit risk on our liabilities.

Commodity and interest rate derivatives reflect positions held by us. Most over-the-counter commodity and interest rate derivatives are valued using financial models which utilize observable inputs for similar instruments and are classified within Level 2. Other derivatives are valued utilizing inputs that are not observable for substantially the full term of the contract, or for which the impact of the unobservable period is significant to the fair value of the derivative. Such derivatives are classified within Level 3. See Note 17 for discussion of risk management activities and derivative transactions.

NDT funds reflect the assets of the Utilities' nuclear decommissioning trusts. The assets of the trusts are invested primarily in exchange-traded equity securities (classified within Level 1) and marketable debt securities, most of which are valued using Level 1 inputs for similar instruments and are classified within Level 2.

Other marketable securities primarily represent available-for-sale debt securities used to fund certain employee benefit costs.

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

The following table sets forth a reconciliation of changes in the fair value of our commodity derivatives classified as Level 3 in the fair value hierarchy for the 12 months ended December 31, 2009.

(in millions)	
Derivatives, net at January 1, 2009	$(41)
Total gains (losses), realized and unrealized	
Included in earnings	–
Included in other comprehensive income	–
Deferred as regulatory assets and liabilities, net	(13)
Purchases, issuances and settlements, net	–
Transfers in (out) of Level 3, net	15
Derivatives, net at December 31, 2009	$(39)

Substantially all unrealized gains and losses on derivatives are deferred as regulatory liabilities or assets consistent with ratemaking treatment.

Transfers in (out) of Level 3 represent existing assets or liabilities that were previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period. Transfers into Level 3 are measured at the beginning of the period, and transfers out of Level 3 are measured at the end of the period.

14. INCOME TAXES

We provide deferred income taxes for temporary differences between book and tax carrying amounts of assets and liabilities. Investment tax credits related to regulated operations have been deferred and are being amortized over the estimated service life of the related properties. To the extent that the establishment of deferred income taxes is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to GAAP for regulated operations. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount that, in our judgment, is greater than 50 percent likely to be realized.

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

(in millions)	2009	2008
Deferred income tax assets		
ARO liability	$127	$264
Derivative instruments	159	298
Income taxes refundable through future rates	225	111
Pension and other postretirement benefits	508	544
Other	374	340
Federal income tax credit carry forward	712	802
State net operating loss carry forward (net of federal expense)	66	64
Valuation allowance	(55)	(55)
Total deferred income tax assets	2,116	2,368
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	(1,889)	(1,665)
Deferred fuel recovery	(74)	(186)
Income taxes recoverable through future rates	(782)	(959)
Other	(264)	(141)
Total deferred income tax liabilities	(3,009)	(2,951)
Total net deferred income tax liabilities	$(893)	$(583)

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

(in millions)	2009	2008
Current deferred income tax assets, included in prepayments and other current assets	$168	$96
Noncurrent deferred income tax assets, included in other assets and deferred debits	37	32
Current deferred income tax liabilities, included in other current liabilities	–	(1)
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	(1,098)	(710)
Total net deferred income tax liabilities	$(893)	$(583)

At December 31, 2009, the federal income tax credit carry forward includes $712 million of alternative minimum tax credits that do not expire.

At December 31, 2009, we had gross state net operating loss carry forwards of $1.6 billion that will expire during the period 2010 through 2029.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We had a net increase of less than $1 million in our valuation allowances during 2009.

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:

	2009	2008	2007
Effective income tax rate	32.1%	33.7%	32.3%
State income taxes, net of federal benefit	(3.7)	(3.8)	(2.8)
Investment tax credit amortization	0.8	1.0	1.1
Employee stock ownership plan dividends	1.0	1.0	1.1
Domestic manufacturing deduction	0.8	0.3	1.0
AFUDC equity	2.2	2.5	0.7
Other differences, net	1.8	0.3	1.6
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)	2009	2008	2007
Current – federal	$227	$38	$285
– state	41	12	36
Deferred – federal	114	305	13
– state	25	49	11
Investment tax credit	(10)	(12)	(12)
State net operating loss carry forward	–	(6)	1
Beginning-of-the-year valuation allowance change	–	9	–
Total income tax expense	$397	$395	$334

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

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

- Taxes related to discontinued operations recorded net of tax for 2009, 2008 and 2007, which are presented separately in Notes 3A through 3E.
- Taxes related to other comprehensive income recorded net of tax for 2009, 2008 and 2007, 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. No net current tax benefit was recorded in common stock during 2009 and 2008.

- Taxes of $2 million and $4 million that reduced retained earnings and increased regulatory assets, respectively, due to the cumulative effect of adopting new guidance for uncertain tax positions on January 1, 2007.

At December 31, 2009, 2008 and 2007, our liability for unrecognized tax benefits was $160 million, $104 million and $93 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $9 million, $8 million and $10 million, respectively, at December 31, 2009, 2008 and 2007. The following table presents the changes to unrecognized tax benefits during the years ended December 31, 2009, 2008 and 2007:

(in millions)	2009	2008	2007
Unrecognized tax benefits at beginning of period	$104	$93	$126
Gross amounts of increases as a result of tax positions taken in a prior period	11	17	32
Gross amounts of decreases as a result of tax positions taken in a prior period	(3)	(11)	(41)
Gross amounts of increases as a result of tax positions taken in the current period	52	8	22
Gross amounts of decreases as a result of tax positions taken in the current period	(4)	(2)	(32)
Amounts of net increases (decreases) relating to settlements with taxing authorities	–	1	(14)
Reductions as a result of a lapse of the applicable statute of limitations	–	(2)	–
Unrecognized tax benefits at end of period	$160	$104	$93

We file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Our open federal tax years are from 2004 forward, and our open state tax years in our major jurisdictions are generally from 2003 forward. The IRS is currently examining our federal tax returns for years 2004 through 2005. We cannot predict when the review will be completed. Although the timing for completion of the IRS' review is uncertain, it is reasonably possible that unrecognized tax benefits will decrease by up to approximately $60 million during the 12-month period ending December 31, 2010, due to expected settlements. Any potential decrease will not have a material impact on our results of operations.

We include interest expense related to unrecognized tax benefits in interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2009, 2008 and 2007, the net interest expense related to unrecognized tax benefits was $9 million, $4 million and $1 million, respectively, of which a respective $5 million, $1 million and $15 million expense component was deferred as a regulatory asset by PEF, which is amortized as a charge to interest expense over a three-year period or less. During 2008, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2009 and 2007, there were no penalties related to unrecognized tax benefits. During 2008, less than $1 million was recorded for penalties related to unrecognized tax benefits. At December 31, 2009 and 2008, we had accrued $36 million and $27 million, respectively, for interest and penalties, which are included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

15. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four coal-based solid synthetic fuels limited liability companies, three of which were wholly owned (Earthco), purchased by subsidiaries of Florida Progress in October 1999. All of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007 (See Note 3A). The payments are based on the net after-tax cash flows the facilities 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, 2009 and 2008, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million and $34 million, respectively.

During the year ended December 31, 2008, a $6 million deposit was made into the CVO trust for the CVO holders' share of the disposition proceeds from the sale of one of the Earthco synthetic fuels facilities (See Note 3E). Disposition proceeds payments will not generally be made to CVO holders until the termination of all indemnity obligations under the purchase and sale agreement related to the disposition. Future payments will include principal and interest earned during the investment period net of expenses deducted. The interest earned on the payments held in trust for 2009 and 2008 was insignificant. The asset is included in other assets and deferred debits on the Consolidated Balance Sheets at December 31, 2009 and 2008.

16. BENEFIT PLANS

A. Postretirement Benefits

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

COSTS OF BENEFIT PLANS

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

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

The table below provides the components of the net periodic benefit cost for 2009, 2008 and 2007. A portion of net periodic benefit cost is capitalized as part of construction work in progress.

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2009**	2008	2007	**2009**	2008	2007
Service cost	**$42**	$46	$46	**$7**	$8	$7
Interest cost	**138**	128	123	**31**	34	32
Expected return on plan assets	**(133)**	(170)	(155)	**(4)**	(6)	(6)
Amortization of actuarial loss[a]	54	8	15	**1**	1	2
Other amortization, net[a]	**6**	2	2	**5**	5	5
Net periodic cost before deferral[b]	**$107**	$14	$31	**$40**	$42	$40

[a] Adjusted to reflect PEF's rate treatment (See Note 16B).
[b] In June 2009, PEF received permission from the FPSC to defer the retail portion of certain pension expense in 2009. The FPSC order did not change the total net periodic pension cost, but defers a portion of these costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension cost as a regulatory asset (See Note 7C).

The following table provides a summary of amounts recognized in other comprehensive income and other comprehensive income reclassification adjustments for amounts included in net income, for 2009, 2008 and 2007. The table also includes comparable items that affected regulatory assets of PEC and PEF.

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2009	2008	2007	2009	2008	2007
Other comprehensive income (loss)						
Recognized for the year						
Net actuarial (loss) gain	$(1)	$(64)	$24	$4	$(8)	$16
Other, net	–	(6)	(1)	–	–	–
Reclassification adjustments						
Net actuarial loss	5	1	2	1	–	–
Other, net	–	1	1	1	–	–
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial gain (loss)	10	(735)	66	64	(73)	82
Other, net	(3)	(36)	(8)	–	–	–
Amortized to income[a]						
Net actuarial loss	49	7	13	–	1	2
Other, net	6	1	1	4	5	4

[a] These amounts were amortized as a component of net periodic cost, as reflected in the previous net periodic cost table. Refer to that table for information regarding the deferral of a portion of net periodic pension cost.

The following weighted-average actuarial assumptions were used in the calculation of our net periodic cost:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	2009	2008	2007	2009	2008	2007
Discount rate	6.30%	6.20%	5.95%	6.20%	6.20%	5.95%
Rate of increase in future compensation						
Bargaining	4.25%	4.25%	4.25%	–	–	–
Supplementary plans	5.25%	5.25%	5.25%	–	–	–
Expected long-term rate of return on plan assets	8.75%	9.00%	9.00%	6.80%	8.10%	7.70%

The expected long-term rates of return on plan assets were determined by considering long-term projected returns based on the plans' target asset allocations. Specifically, return rates were developed for each major asset class and weighted based on the target asset allocations. The projected returns were benchmarked against historical returns for reasonableness. We decreased our expected long-term rate of return on pension assets by 0.25% in 2009, primarily due to the uncertainties resulting from the severe capital market deterioration in 2008. See the "Assets of Benefit Plans" section below for additional information regarding our investment policies and strategies.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

GAAP requires us to recognize in our statement of financial condition the funded status of our pension and other postretirement benefit plans, measured as the difference between the fair value of the plan assets and the benefit obligation as of the end of the fiscal year.

Reconciliations of the changes in benefit obligations and the funded status as of December 31, 2009 and 2008, are presented in the table below, followed by related supplementary information.

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2009	2008	2009	2008
Projected benefit obligation at January 1	$2,234	$2,142	$608	$541
Service cost	42	46	7	8
Interest cost	138	128	31	34
Settlements	(9)	–	–	–
Benefit payments	(124)	(127)	(40)	(35)
Plan amendment	3	42	–	–
Actuarial loss (gain)	138	3	(63)	60
Obligation at December 31	2,422	2,234	543	608
Fair value of plan assets at December 31	1,673	1,285	55	52
Funded status	$(749)	$(949)	$(488)	$(556)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.422 billion and $2.234 billion at December 31, 2009 and 2008, respectively. Those plans had accumulated benefit obligations totaling $2.378 billion and $2.196 billion at December 31, 2009 and 2008, respectively, and plan assets of $1.673 billion and $1.285 billion at December 31, 2009 and 2008, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2009	2008	2009	2008
Current liabilities	$(9)	$(10)	$–	$(1)
Noncurrent liabilities	(740)	(939)	(488)	(555)
Funded status	$(749)	$(949)	$(488)	$(556)

The following table 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)	2009	2008	2009	2008
Recognized in accumulated other comprehensive loss				
Net actuarial loss (gain)	$83	$87	$(5)	$–
Other, net	10	11	–	–
Recognized in regulatory assets, net				
Net actuarial loss	806	865	32	97
Other, net	59	62	14	18
Total not yet recognized as a component of net periodic cost[a]	$958	$1,025	$41	$115

[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 2010.

(in millions)	Pension Benefits	Other Postretirement Benefits
Amortization of actuarial loss[a]	$50	$1
Amortization of other, net[a]	6	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	
	2009	2008	2009	2008
Discount rate	6.00%	6.30%	6.05%	6.20%
Rate of increase in future compensation				
Bargaining	4.50%	4.25%	–	–
Supplementary plans	5.25%	5.25%	–	–
Initial medical cost trend rate for pre-Medicare Act benefits	–	–	8.50%	9.00%
Initial medical cost trend rate for post-Medicare Act benefits	–	–	8.50%	9.00%
Ultimate medical cost trend rate	–	–	5.00%	5.00%
Year ultimate medical cost trend rate is achieved	–	–	2016	2016

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

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan. Therefore, we use the traditional unit credit method for purposes of measuring the benefit obligation of this plan.

Under the traditional unit credit method, no assumptions are included about future changes in compensation, and the accumulated benefit obligation and projected benefit obligation are the same.

MEDICAL COST TREND RATE SENSITIVITY

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

(in millions)	
1 percent increase in medical cost trend rate	
Effect on total of service and interest cost	$2
Effect on postretirement benefit obligation	26
1 percent decrease in medical cost trend rate	
Effect on total of service and interest cost	(1)
Effect on postretirement benefit obligation	(21)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation table that follows, our employer contributions for 2009 and 2008 include contributions directly to pension plan assets of $222 million and $33 million, respectively. Substantially all of the remaining employer contributions represent benefit payments made directly from our assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the cost after participant contributions. Participant contributions represent approximately 20 percent of gross benefit payments. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2009 and 2008, the subsidies totaled $3 million.

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

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2009	2008	2009	2008
Fair value of plan assets at January 1	$1,285	$1,996	$52	$75
Actual return on plan assets	279	(627)	9	(16)
Benefit payments, including settlements	(133)	(127)	(40)	(35)
Employer contributions	242	43	34	28
Fair value of plan assets at December 31	$1,673	$1,285	$55	$52

Our primary objectives when setting investment policies and strategies are to manage the assets of the pension plan to ensure that sufficient funds are available at all times to finance promised benefits and to invest the funds such that contributions are minimized, within acceptable risk limits. We periodically perform studies to analyze various aspects of our pension plans including asset allocations, expected portfolio return, pension contributions and net funded status. One of our key investment objectives is to achieve a rolling 10-year annual return of 6 percent over the rate of inflation. The target pension asset allocations are 40 percent domestic equity, 20 percent international equity, 10 percent domestic fixed income, 15 percent global fixed income, 10 percent private equity and timber and 5 percent hedge funds. Tactical shifts (plus or minus 5 percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes. Domestic equity includes investments across large, medium and small capitalized domestic stocks, using investment managers with value, growth and core-based investment strategies. International equity includes investments in foreign stocks in both developed and emerging market countries, using a mix of value and growth based investment strategies. Domestic fixed income primarily includes domestic investment grade fixed income investments. Global fixed income includes domestic and foreign fixed income investments. A substantial portion of OPEB plan assets are managed with pension assets. The remaining OPEB plan assets, representing all PEF's OPEB plan assets, are invested in domestic governmental securities.

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

	Pension Benefit Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Cash and cash equivalents	$1	$96	$–	$97
Domestic equity securities	263	1	–	264
Private equity securities	–	–	122	122
Corporate bonds	–	67	–	67
U.S. state and municipal debt	–	4	–	4
U.S. and foreign government debt	25	95	–	120
Mortgage backed securities	–	22	–	22
Commingled funds	–	888	–	888
Hedge funds	–	47	2	49
Timber investments	–	–	14	14
Credit default swaps	–	20	–	20
Interest rate swaps and other investments	–	36	–	36
Total assets	$289	$1,276	$138	$1,703
Liabilities				
Foreign currency contracts	(5)	–	–	(5)
Credit default swaps	–	(20)	–	(20)
Interest rate swaps and other investments	–	(5)	–	(5)
Total liabilities	(5)	(25)	–	(30)
Fair value of plan assets	$284	$1,251	$138	$1,673

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

The following table sets forth a reconciliation of changes in the fair value of our pension plan assets classified as Level 3 in the fair value hierarchy for the year ended December 31, 2009.

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
Balance at January 1	$111	$2	$18	$131
Net realized and unrealized (losses)[a]	(10)	–	(4)	(14)
Purchases, sales and distributions, net	21	–	–	21
Balance at December 31	$122	$2	$14	$138

[a] Substantially all amounts relate to investments held at December 31, 2009.

The determination of the fair values of pension and postretirement plan assets incorporates various factors required under GAAP. The assets of the plan include exchange traded securities (classified within Level 1) and other marketable debt and equity securities, most of which are valued using Level 1 inputs for similar instruments, and are classified within Level 2 investments.

Most over-the-counter investments are valued using observable inputs for similar instruments or prices from similar transactions and are classified as Level 2. Over-the-counter investments where significant unobservable inputs are used, such as financial pricing models, are classified as Level 3 investments.

Investments in private equity are valued using observable inputs, when available, and also include comparable market transactions, income and cost basis valuation techniques. The market approach includes using comparable market transactions or values. The income approach generally consists of the net present value of estimated future cash flows, adjusted as appropriate for liquidity, credit, market and/or other risk factors. Private equity investments are classified as Level 3 investments.

Investments in commingled funds are not publicly traded, but the underlying assets held in these funds are traded in active markets and the prices for the assets are readily observable. Holdings in commingled funds are classified as Level 2 investments.

Investments in timber are valued primarily on valuations prepared by independent property appraisers. These appraisals are based on cash flow analysis, current market capitalization rates, recent comparable sales transactions, actual sales negotiations and bona fide purchase offers. Inputs include the species, age, volume and condition of timber stands growing on the land; the location, productivity, capacity and accessibility of the timber tracts; current and expected log prices; and current local prices for comparable investments. Timber investments are classified as Level 3 investments.

Hedge funds are based primarily on the net asset values and other financial information provided by management of the private investment funds. Hedge funds are classified as Level 2 if the plan is able to redeem the investment with the investee at net asset value as of the measurement date, or at a later date within a reasonable period of time. Hedge funds are classified as Level 3 if the investment cannot be redeemed at net asset value or it cannot be determined when the fund will be redeemed.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2010, we expect to make $120 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 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $158, $161, $167, $170, $178 and $961, respectively. The expected benefit payments for the OPEB plan for 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $37, $40, $42, $45, $46 and $251, 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 2010 through 2014 and in total for 2015 through 2019, in millions, are approximately $4, $4, $5, $5, $6 and $40, 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 and financial reviews using a combination of financial analysis and publicly available credit ratings of such counterparties. Potential nonperformance by counterparties is not expected to have a material effect on our financial position or results of operations.

A. Commodity Derivatives

GENERAL

Most of our physical commodity contracts are not derivatives or qualify as normal purchases or sales. Therefore, such contracts are not recorded at fair value.

DISCONTINUED OPERATIONS

As discussed in Note 3C, in 2007 our subsidiary PVI sold or assigned substantially all of its CCO physical and commercial assets and liabilities representing substantially all of our nonregulated energy marketing and trading operations. 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 was included in discontinued operations on the Consolidated Statements of Income.

In 2007, we entered into derivative contracts to hedge economically a portion of our synthetic fuels cash flow exposure to the risk of rising oil prices. 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 in January 2008, with no material impact to 2008 earnings. Approximately 34 percent of the notional quantity of these contracts was entered into by Ceredo Synfuel LLC (Ceredo). As discussed in Note 3E, we disposed of our 100 percent ownership interest in Ceredo in March 2007. Progress Energy is the primary beneficiary of, and continues to consolidate, Ceredo in accordance with GAAP for variable interest entities, but we have recorded a 100 percent noncontrolling interest. Consequently, subsequent to the disposal there is no net earnings impact for the portion of the contracts entered into by Ceredo. 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, $42 million of which was attributed to noncontrolling interest for the portion of the gain subsequent to the disposal of Ceredo.

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges mitigate exposures to fluctuations in commodity prices, these instruments are not designated as hedges for accounting purposes and are monitored consistent with trading positions.

The Utilities have derivative instruments through 2015 related to their exposure to price fluctuations on fuel oil and natural gas purchases. The majority of our financial hedge agreements will settle in 2010 and 2011. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Consolidated Balance Sheets until the contracts are settled (See Note 7A). After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause.

Certain hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

Certain counterparties have held cash collateral from PEC in support of these instruments. PEC had a $7 million and an $18 million cash collateral asset included in derivative collateral posted on the Consolidated Balance Sheets at December 31, 2009 and 2008, respectively. At December 31, 2009, PEC had 50.3 million MMBtu notional of natural gas related to outstanding commodity derivative swaps that were entered into to hedge forecasted natural gas purchases. Changes in natural gas prices and settlements of financial hedge agreements since December 31, 2008, have impacted PEF's cash collateral asset included in derivative collateral posted on the Consolidated Balance Sheets, which was $139 million at December 31, 2009, compared to $335 million at December 31, 2008. At December 31, 2009, PEF had 182.4 million MMBtu notional of natural gas and 56.3 million gallons notional of oil related to outstanding commodity derivative swaps that were entered into to hedge forecasted oil and natural gas purchases.

CASH FLOW HEDGES

The Utilities designate a portion of commodity derivative instruments as cash flow hedges. From time to time we 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. We also hedge exposure to market risk associated with fluctuations in the price of fuel for fleet vehicles. At December 31, 2009, we had 0.4 million gallons notional of gasoline and 0.5 million gallons notional of heating oil related to outstanding commodity derivative swaps at PEC and at PEF that were entered into to hedge forecasted gasoline and diesel purchases. Realized gains and losses are recorded net as part of fleet vehicle fuel costs. At December 31, 2009 and 2008, 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 2009, 2008 and 2007.

At December 31, 2009 and 2008, 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. Our cash flow hedging strategies are primarily accomplished through the use of forward starting swaps, and our fair value hedging strategies are primarily accomplished through the use of fixed-to-floating swaps. The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by the counterparty, the exposure in these transactions is the cost of replacing the agreements at current market rates.

CASH FLOW HEDGES

At December 31, 2009, all open forward starting swaps will reach their mandatory termination dates within three years. At December 31, 2009, including amounts related to terminated hedges, we had $35 million of after-tax losses recorded in accumulated other comprehensive income related to interest cash flow hedges. It is expected that in the next 12 months losses of $7 million, net of tax, will be reclassified to interest expense. The actual amount that will be reclassified to earnings may vary from the expected amount as a result of the timing of debt issuances and changes in market value of currently open forward starting swaps.

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

At December 31, 2007, including amounts related to terminated hedges, we had $24 million of after-tax losses recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2009, we had $325 million notional of open forward starting swaps. At December 31, 2008, we had $450 million notional of open forward starting swaps. During January 2010, we entered into $175 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, 2009 and 2008, we did not have any outstanding positions in such contracts.

C. Contingent Features

Certain of our derivative instruments contain provisions defining fair value thresholds requiring the posting of collateral for hedges in a liability position greater than such threshold amounts. The thresholds are tiered and based on the individual company's credit rating with each of the major credit rating agencies. Higher credit ratings have a higher threshold requiring a lower amount of the outstanding liability position to be covered by posted collateral. Conversely, lower credit ratings require a higher amount of the outstanding liability position to be covered by posted collateral. If our credit ratings were to be downgraded, we may have to post additional collateral on certain hedges in liability positions.

In addition, certain of our derivative instruments contain provisions that require our debt to maintain an investment grade credit rating from each of the major credit rating agencies. If our debt were to fall below investment grade, we would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions.

The aggregate fair value of all derivative instruments with credit risk-related contingent features that were in a liability position at December 31, 2009, was $405 million, for which we had posted collateral of $146 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2009, we would have been required to post an additional $260 million of collateral with our counterparties.

D. Derivative Instrument and Hedging Activity Information

The following table presents the fair value of derivative instruments at December 31, 2009 and 2008:

Instrument/Balance sheet location	December 31, 2009		December 31, 2008	
(in millions)	Asset	Liability	Asset	Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		$–		$(2)
Interest rate derivatives				
Prepayments and other current assets	$5		$–	
Other assets and deferred debits	14		–	
Derivative liabilities, current		–		(65)
Total derivatives designated as hedging instruments	19	–	–	(67)
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	11		9	
Other assets and deferred debits	9		1	
Derivative liabilities, current		(189)		(425)
Derivative liabilities, long-term		(235)		(263)
CVOs[b]				
Other liabilities and deferred credits		(15)		(34)
Fair value of derivatives not designated as hedging instruments	20	(440)	10	(722)
Fair value loss transition adjustment[c]				
Derivative liabilities, current		(1)		(1)
Derivative liabilities, long-term		(4)		(6)
Total derivatives not designated as hedging instruments	20	(445)	10	(729)
Total derivatives	$39	$(445)	$10	$(796)

[a] Substantially all of these contracts receive regulatory treatment.
[b] The Parent issued 98.6 million CVOs in connection with the acquisition of Florida Progress during 2000 (See Note 15).
[c] In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contract (See Note 20).

The following tables present the effect of derivative instruments on the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Income for the years ended December 31, 2009 and 2008:

Derivatives Designated as Hedging Instruments								
Instrument	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a]		Location of Gain or (Loss) Reclassified from Accumulated OCI into Income[a]	Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a]		Location of Gain or (Loss) Recognized in Income on Derivatives[b]	Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b]	
(in millions)	2009	2008		2009	2008		2009	2008
Commodity cash flow derivatives	$1	$(2)		$–	$–		$–	$–
Interest rate derivatives[c]	15	(35)	Interest charges	(6)	(3)	Interest charges	(3)	1

[a] Effective portion.
[b] Related to ineffective portion and amount excluded from effectiveness testing.
[c] Amounts in accumulated other comprehensive income related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

Derivatives Not Designated as Hedging Instruments				
Instrument	Realized Gain or (Loss)[a]		Unrealized Gain or (Loss)[b]	
(in millions)	2009	2008	2009	2008
Commodity derivatives	$(659)	$174	$(387)	$(653)

[a] After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause and are reflected in fuel used in electric generation on the Consolidated Statements of Income.
[b] Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
(in millions)		2009	2008
Commodity derivatives	Other, net	$1	$(3)
Fair value loss transition adjustment	Other, net	2	3
CVOs	Other, net	19	–
Total		$22	$–

18. RELATED PARTY TRANSACTIONS

As a part of normal business, we enter into various agreements providing financial or performance assurances to third parties. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. Our guarantees may include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements, trading operations and cash management. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2009, the Parent had issued $391 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). Subsequent to December 31, 2009, the Parent issued a $76 million guarantee for performance assurance of a wholly owned indirect subsidiary. 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 Sheets.

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

19. FINANCIAL INFORMATION BY BUSINESS SEGMENT

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

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative thresholds for disclosure as separate reportable business segments.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost.

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

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Total
At and for the year ended December 31, 2009					
Revenues					
Unaffiliated	$4,627	$5,249	$9	$–	$9,885
Intersegment	–	2	234	(236)	–
Total revenues	4,627	5,251	243	(236)	9,885
Depreciation, amortization and accretion	470	502	14	–	986
Interest income	5	4	38	(33)	14
Total interest charges, net	195	231	286	(33)	679
Income tax expense (benefit)[a]	294	209	(87)	–	416
Ongoing Earnings (loss)	540	460	(154)	–	846
Total assets	13,502	13,100	20,538	(15,904)	31,236
Capital and investment expenditures	962	1,532	21	(12)	2,503
At and for the year ended December 31, 2008					
Revenues					
Unaffiliated	$4,429	$4,730	$8	$–	$9,167
Intersegment	–	1	361	(362)	–
Total revenues	4,429	4,731	369	(362)	9,167
Depreciation, amortization and accretion	518	306	15	–	839
Interest income	12	9	38	(35)	24
Total interest charges, net	207	208	259	(35)	639
Income tax expense (benefit)	298	181	(84)	–	395
Ongoing Earnings (loss)	531	383	(138)	–	776
Total assets	13,165	12,471	17,483	(13,246)	29,873
Capital and investment expenditures	939	1,601	33	(13)	2,560
At 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, amortization and accretion	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
Ongoing Earnings (loss)	498	315	(118)	–	695
Total assets	11,955	10,063	16,356	(12,088)	26,286
Capital and investment expenditures	941	1,262	3	(2)	2,204

[a] Income tax expense (benefit) for 2009 excludes tax impact of $17 million benefit at PEC and $1 million benefit at Corporate and Other for Ongoing Earnings adjustments.

Management uses the non-GAAP financial measure "Ongoing Earnings" as a performance measure to evaluate the results of our segments and operations. A reconciliation of consolidated Ongoing Earnings to net income attributable to controlling interests for the years ended 2009, 2008 and 2007, respectively, is as follows:

(in millions)	2009	2008	2007
Ongoing Earnings	$846	$776	$695
CVO mark-to-market	19	–	(2)
Impairment, net of tax benefit of $1	(2)	–	–
Plant retirement charge, net of tax benefit of $11	(17)	–	–
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax benefit of $6 (See Note 24)	(10)	–	–
Valuation allowance and related net operating loss carry forward	–	(3)	–
Continuing income attributable to non-controlling interests, net of tax	4	5	9
Income from continuing operations	840	778	702
Discontinued operations, net of tax	(79)	58	(206)
Net income attributable to noncontrolling interests, net of tax	(4)	(6)	8
Net income attributable to controlling interests	$757	$830	$504

20. OTHER INCOME AND EXPENSE

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

(in millions)	2009	2008	2007
Nonregulated energy and delivery services income, net	$17	$17	$12
Fair value loss transition adjustment amortization (Note 17D)	2	3	4
CVO unrealized gain (loss), net (Note 15)	19	–	(2)
Donations	(20)	(25)	(22)
Other, net	(12)	(12)	1
Other, net	$6	$(17)	$(7)

21. ENVIRONMENTAL MATTERS

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

A. Hazardous and Solid Waste

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

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 current liabilities and other liabilities and deferred credits on the Consolidated Balance Sheets, at December 31 were:

(in millions)	2009	2008
PEC		
MGP and other sites[a]	$13	$16
PEF		
Remediation of distribution and substation transformers	20	22
MGP and other sites	9	15
Total PEF environmental remediation accruals[b]	29	37
Total Progress Energy environmental remediation accruals	$42	$53

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

Including PEC's Ward Transformer site located in Raleigh, N.C. (Ward), PEF's distribution and substation transformers sites, and the Utilities' MGP sites discussed below, for the year ended December 31, 2009, we accrued approximately $16 million and spent approximately $27 million. For the year ended December 31, 2008, we accrued approximately $25 million and spent approximately $36 million. For the year ended December 31, 2007, we accrued approximately $8 million and spent approximately $27 million.

In addition to these sites, we incurred indemnity obligations related to certain pre-closing liabilities of divested subsidiaries, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC has recorded a minimum estimated total remediation cost for all of its remaining MGP sites based upon its historical experience with remediation of several of its MGP sites. The accruals for PEF's MGP and other sites relate to two former MGP sites and other sites associated with PEF that have required, or are anticipated to require, investigation and/or remediation. The maximum amount of the range for all the sites cannot be determined at this time. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

In 2004, the EPA advised PEC that it had been identified as a PRP at the Ward site. The EPA offered PEC and a number of other PRPs the opportunity to negotiate the removal action for the Ward site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the Ward site. Subsequently, PEC and other PRPs signed a settlement agreement, which requires the participating PRPs to remediate the Ward site. At December 31, 2009 and 2008, PEC's recorded liability for the site was approximately $4 million and $7 million, respectively. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future. On September 12, 2008, PEC filed an initial civil action against a number of PRPs seeking contribution for and recovery of costs incurred in remediating the Ward site, as well as a declaratory judgment that defendants are jointly and severally liable for response costs at the site. On March 13, 2009, a subsequent action was filed against additional PRPs, and on April 30, 2009, suit was filed against the remaining approximately 160 PRPs. PEC has settled with a number of the PRPs and is in active settlement negotiations with others. With respect to the defendants that do not settle, the federal district court in which this matter is pending requires that alternative dispute resolution be pursued early in civil litigation but it is unclear what process the court will require. The outcome of these matters cannot be predicted.

On September 30, 2008, the EPA issued a Record of Decision for the operable unit for stream segments downstream from the Ward site (Ward OU1) and advised 61 parties, including PEC, of their identification as PRPs for Ward OU1 and for the operable unit for further investigation at the Ward facility and certain adjacent areas (Ward OU2). The EPA's estimate for the selected remedy for Ward OU1 is approximately $6 million. The EPA offered PEC and the other PRPs the opportunity to negotiate implementation of a response action for Ward OU1 and a remedial investigation and feasibility study for Ward OU2, as well as reimbursement to the EPA of approximately $1 million for the EPA's past expenditures in addressing conditions at the site. On January 19, 2009, PEC and several of the other participating PRPs at the Ward site submitted a letter containing a good faith response to the EPA's special notice letter. Another group of PRPs separately submitted a good faith response, which the EPA advised would be used to negotiate implementation of the required actions. The other PRPs' good faith response was subsequently withdrawn. Discussions among representatives of certain PRPs, including PEC, and the EPA are ongoing. Although a loss is considered probable, an agreement among the PRPs for these matters has not been reached; consequently, it is not possible at this time to reasonably estimate the total amount of PEC's obligation, if any, for Ward OU1 and Ward OU2.

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF has reviewed all distribution transformer sites and all substation sites for mineral oil-impacted soil caused by equipment integrity issues. Should further distribution transformer sites be identified outside of this population, the distribution O&M costs will not be recoverable through the ECRC. For the year ended December 31, 2009, PEF accrued approximately $13 million due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $15 million related to the remediation of transformers. For the year ended December 31, 2008, PEF accrued approximately $17 million, due to the identification of additional transformer sites and an increase in estimated remediation costs, and spent approximately $26 million related to the remediation of transformers. 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. At December 31, 2009 and 2008, PEF has recorded a regulatory asset for the probable recovery of these costs through the ECRC (See Note 7A).

B. Air and Water Quality

At December 31, 2009 and 2008, we were subject to various current federal, state and local environmental compliance laws and regulations governing air and water quality, resulting in capital expenditures and increased O&M expenses. These compliance laws and regulations included the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR), the Clean Smokestacks Act, enacted in June 2002 and mercury regulation. PEC's and PEF's environmental compliance capital expenditures related to these regulations began in 2002 and 2005, respectively. At December 31, 2009, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $2.119 billion, including $1.054 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and $1.065 billion at PEF, which related entirely to in-process CAIR projects. At December 31, 2008, cumulative environmental compliance capital expenditures to date with regard to these environmental laws and regulations were $1.859 billion, including $1.012 billion at PEC, which primarily relates to Clean Smokestacks Act projects, and $847 million at PEF, which related entirely to in-process CAIR projects.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) issued its decision on multiple challenges to the CAIR, which vacated the CAIR in its entirety. On December 23, 2008, in response to petitions for rehearing filed by a number of parties, the D.C. Court of Appeals remanded the CAIR without vacating the rule for the EPA to conduct further proceedings consistent with the D.C. Court of Appeals' prior opinion. The outcome of the EPA's further proceedings cannot be predicted. Because the D.C. Court of Appeals December 23, 2008 decision remanded the CAIR, the current implementation of the CAIR continues to fulfill best available retrofit technology (BART) for SO_2 and NOx for BART-affected units under the CAVR. Should this determination change as the CAIR is revised, CAVR compliance eventually may require consideration of NOx and SO_2 emissions in addition to particulate matter emissions for BART-eligible units.

On February 8, 2008, the D.C. Court of Appeals vacated the delisting determination and the Clean Air Mercury Rule (CAMR). The U.S. Supreme Court declined to hear an appeal of the D.C. Court of Appeals' decision in January 2009. As a result, the EPA subsequently announced that it will develop a maximum achievable control technology (MACT) standard consistent with the agency's original listing determination. The three states in which the Utilities operate adopted mercury regulations implementing CAMR and submitted their state implementation rules to the EPA. It is uncertain how the decision that vacated the federal CAMR will affect the state rules; however, state-specific provisions are likely to remain in effect. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. We are currently evaluating the impact of these decisions. The outcome of these matters cannot be predicted.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at CR5 and CR4. The CR5 project was placed in service on December 2, 2009, and the CR4 project is expected to be placed in service in 2010. Under an agreement with the FDEP, PEF will retire CR1 and CR2 as coal-fired units and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was anticipated to be around 2020. As discussed under "Other Matters – Nuclear," PEF expects the schedule for the commercial operation of Levy to shift later than the 2016 to 2018 timeframe by a minimum of 20 months. PEF is required to advise the FDEP of any developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated completion date of the first fuel cycle for Levy Unit 2. PEF has advised the FDEP of a Levy schedule shift. We are currently evaluating the impacts of the Levy schedule. We cannot predict the outcome of this matter.

We account for emission allowances as inventory using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. The EPA is continuing to record allowance allocations under the CAIR NOx trading program, in some cases for years beyond the estimated two-year period for promulgation of a replacement rule. The EPA's continued recording of CAIR NOx allowance allocations does not guarantee that allowances will continue to be usable for compliance after a replacement rule is finalized or that they will continue to have value in the future. SO_2 emission allowances will be utilized to comply with existing Clean Air Act requirements. PEF's CAIR expenses, including NOx allowance inventory expense, are recoverable through the ECRC. At December 31, 2009 and 2008, PEC had approximately $13 million and $22 million, respectively, in SO_2 emission allowances and an immaterial amount of NOx emission allowances. At December 31, 2009 and 2008, PEF had approximately $7 million and $11 million, respectively, in SO_2 emission allowances and approximately $36 million and $65 million, respectively, in NOx emission allowances.

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, in 2005 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. All of PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, including projects at the Mayo and Roxboro Plants, have been placed in service and PEC estimates its remaining exposure is not material. See Note 22C for further discussion of PEC's indemnification liability. 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. On September 5, 2008, the NCUC ordered that PEC shall be allowed to include in rate base all reasonable and prudently incurred environmental compliance costs in excess of $584 million, including eligible compliance costs in excess of the joint owner's share, as the projects are closed to plant in service.

22. COMMITMENTS AND CONTINGENCIES

A. Purchase Obligations

In most cases, our purchase obligation contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. At December 31, 2009, the following table reflects contractual cash obligations and other commercial commitments in the respective periods in which they are due:

(in millions)	2010	2011	2012	2013	2014	Thereafter
Fuel	$2,647	$2,335	$1,953	$1,706	$1,405	$8,217
Purchased power	445	467	447	445	367	3,636
Construction obligations	1,820	1,725	1,453	1,524	1,313	1,543
Other purchase obligations	52	74	36	27	19	163
Total	$4,964	$4,601	$3,889	$3,702	$3,104	$13,559

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel as well as transportation agreements for the related fuel. Our payments under these commitments were $2.921 billion, $3.078 billion and $2.360 billion for 2009, 2008 and 2007, respectively. Essentially all fuel and certain purchased power costs incurred by PEC and PEF are recovered through their respective cost-recovery clauses.

In December 2008, PEF entered into a nuclear fuel fabrication contract for the planned Levy nuclear units. (See discussion under Construction Obligations below.) This $334 million contract (fuel plus related core components) is for the period from 2014 through 2027 and contains exit provisions with termination fees that vary based on the circumstance.

Both PEC and PEF have ongoing purchased power contracts with certain co-generators (primarily QFs) with expiration dates ranging from 2010 to 2029. These purchased power contracts generally provide for capacity and energy payments.

PEC executed two long-term tolling agreements for the purchase of all of the power generated from Broad River LLC's Broad River facility. One agreement provides for the purchase of approximately 500 MW of capacity through May 2021 with average minimum annual payments of approximately $24 million, primarily representing capital-related capacity costs. The second agreement provides for the additional purchase of approximately 335 MW of capacity through February 2022 with average annual payments of approximately $24 million representing capital-related capacity costs. Total purchases for both capacity and energy under the Broad River LLC's Broad River facility agreements amounted to $46 million, $44 million and $39 million in 2009, 2008 and 2007, respectively.

In 2007, PEC executed long-term agreements for the purchase of power from Southern Power Company. The agreements provide for capacity purchases of 305 MW (68 percent of net output) for 2010, 310 MW (30 percent of net output) for 2011 and 150 MW (33 percent of net output) annually thereafter through 2019. Estimated payments for capacity under the agreements are $23 million for 2010, $24 million for 2011 and $12 million annually thereafter through 2019.

PEC has various pay-for-performance contracts with QFs, including renewable energy, for approximately 200 MW of firm capacity expiring at various times through 2029. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. Payments for both capacity and energy are contingent upon the QFs' ability to generate. Payments made under these contracts were $24 million, $55 million and $95 million in 2009, 2008 and 2007, respectively.

PEF has firm contracts for approximately 489 MW of purchased power with other utilities, including a contract with Southern Company for approximately 414 MW (12 percent of net output) of purchased power that ends in 2010. Additional contracts with Southern Company for approximately 424 MW (25 percent of net output) of purchased power annually start in 2010 and extend through 2016. Total purchases, for both energy and capacity, under these agreements amounted to $149 million, $178 million and $161 million for 2009, 2008 and 2007, respectively. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $60 million, $56 million, $44 million, $52 million and $52 million for 2010 through 2014, respectively, and $74 million payable thereafter.

PEF has ongoing purchased power contracts with certain QFs for 682 MW of firm capacity with expiration dates ranging from 2010 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. All ongoing commitments have been approved by the FPSC. Total capacity and energy payments made under these contracts amounted to $435 million, $440 million and $447 million for 2009, 2008 and 2007, respectively. Minimum expected future capacity payments under these contracts are $286 million, $301 million, $313 million, $310 million and $237 million for 2010 through 2014, respectively, and $3.042 billion payable thereafter. The FPSC allows the capacity payments to be recovered through a capacity cost-recovery clause, which is similar to, and works in conjunction with, energy payments recovered through the fuel cost-recovery clause.

In 2009, PEC executed a long-term coal transportation agreement by combining, amending and restating previous agreements with Norfolk Southern Railroad. This agreement will support PEC's coal supply needs through June 2020. Expected future transportation payments under this agreement are $254 million, $264 million, $260 million, $254 million and $277 million for 2010 through 2014, respectively, with approximately $1.679 billion payable thereafter. Coal transportation expenses under these agreements were approximately $283 million in 2009. PEC's state utility commissions allow fuel-related costs to be recovered through fuel cost-recovery clauses.

PEC has entered into conditional agreements for firm pipeline transportation capacity to support PEC's gas supply needs for the period from April 2011 through August 2032. The estimated total cost to PEC associated with these agreements is approximately $1.598 billion, approximately $404 million of which will be classified as a capital lease. Due to the conditions of the capital lease agreement, the capital lease will not be recorded on PEC's balance sheet until approximately 2012. The transactions are subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related interstate and intrastate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in fuel commitments.

In April 2008 (and as amended in February 2009), PEF entered into conditional contracts and extensions of existing contracts with Florida Gas Transmission Company, LLC (FGT) for firm pipeline transportation capacity to support PEF's gas supply needs for the period from April 2011 through March 2036. The total cost to PEF associated with these agreements is estimated to be approximately $1.065 billion. In addition to the FGT contracts, PEF has entered into additional gas supply and transportation arrangements for the period from 2010 through 2036. The total current notional cost of these additional agreements is estimated to be approximately $1.043 billion. The FGT contracts along with the additional gas supply and transportation arrangements are subject to several conditions precedent, including various federal regulatory approvals, the completion and commencement of operation of necessary related interstate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in fuel commitments.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $818 million, $1.018 billion and $698 million for 2009, 2008 and 2007, respectively. The majority of our construction obligations relate to PEF as discussed below.

PEC has purchase obligations related to various capital projects including new generation and transmission obligations. Total payments under PEC's construction-related contracts were $199 million, $140 million and $208 million for 2009, 2008 and 2007, respectively.

The majority of PEF's construction obligations relate to an engineering, procurement and construction (EPC) agreement that PEF entered into in December 2008 with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two approximately 1,100-MW Westinghouse AP1000 nuclear units planned for construction at Levy. Estimated payments and associated escalation totaling $8.608 billion are included for the multi-year contract and do not assume any joint ownership. The contractual obligations presented are in accordance with the existing terms of the EPC agreement. Actual payments under the EPC agreement are dependent upon, and may vary significantly based upon, the decision to build, regulatory approval schedules, timing and escalation of project costs, and the percentages, if any, of joint ownership. In 2009, the NRC indicated it would process PEF's limited work authorization request following COL issuance resulting in a minimum 20-month in-service schedule shift for the Levy units from the original 2016 to 2018 timeframe. Additional schedule shifts are likely given, among other things, the permitting and licensing process, state of Florida and macro-economic conditions and recent FPSC DSM and energy-efficiency goals and other decisions. Uncertainty regarding access to capital on reasonable terms could be another factor to affect the Levy schedule. In light of the regulatory schedule shift and other factors, our anticipated capital expenditures for Levy will be significantly less in the near term than previously planned. Because of anticipated schedule shifts, we are negotiating an amendment to the Levy EPC agreement. We cannot currently predict the impact such amendment might have on the amount and timing of PEF's contractual obligations. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstance. The magnitude of these contract suspension, termination and exit costs cannot be determined at this time and, accordingly, are not reflected in construction obligations. See Note 7C for additional information about the Levy project. PEF made payments of $243 million and $117 million in 2009 and 2008, respectively, toward long-lead equipment and engineering related to the EPC agreement. Additionally, PEF has other construction obligations related to various capital projects including new generation, transmission and environmental compliance. Total payments under PEF's other construction-related contracts were $376 million, $761 million and $490 million for 2009, 2008 and 2007, 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 PEF service agreements related to the Hines Energy Complex and the Bartow Plant. Our payments under these agreements were $56 million, $110 million and $75 million for 2009, 2008 and 2007, respectively.

PEC has various purchase obligations, including obligations for limestone supply and fleet vehicles. Total purchases under these contracts were $14 million, $18 million and $6 million for 2009, 2008 and 2007, respectively.

Among PEF's other purchase obligations, PEF has long-term service agreements for the Hines Energy Complex and the Bartow Plant, emission obligations and fleet vehicles. Total payments under these contracts were $22 million, $58 million and $24 million for 2009, 2008 and 2007, respectively. Future obligations are primarily comprised of the long-term service agreements.

B. Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant. Our rent expense under operating leases totaled $37 million, $38 million and $40 million for 2009, 2008 and 2007, respectively. Our purchased power expense under agreements classified as operating leases was approximately $11 million, $152 million and $69 million in 2009, 2008 and 2007, respectively.

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

(in millions)	2009	2008
Buildings	$267	$267
Less: Accumulated amortization	(37)	(28)
Total	$230	$239

Consistent with the ratemaking treatment for capital leases, capital lease expenses are charged to the same accounts that would be used if the leases were operating leases. Thus, our capital lease expense is generally included in O&M or purchased power expense. Our capital lease expense totaled $26 million each for 2009 and 2008 and $22 million for 2007, which was primarily comprised of PEF's capital lease expense of $24 million each for 2009 and 2008 and $20 million for 2007.

At December 31, 2009, 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
2010	$28	$35
2011	28	29
2012	28	48
2013	36	78
2014	26	77
Thereafter	246	941
Minimum annual payments	392	$1,208
Less amount representing imputed interest	(162)	
Present value of net minimum lease payments under capital leases	$230	

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

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

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

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

In 2005, PEF entered into an agreement for a capital lease for a building completed during 2006. The lease term expires March 2047 and provides for minimum annual payments 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 a 517-MW (100 percent of net output) tolling agreement for purchased power, which is classified as a capital lease of the related plant, for an additional 10 years. The agreement calls for minimum annual payments of approximately $21 million from April 2007 through April 2024, for a total of approximately $348 million.

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's minimum rentals receivable under noncancelable leases are $11 million for 2010 and none thereafter. PEC's rents received are contingent upon usage and totaled $34 million for 2009 and $33 million each for 2008 and 2007. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $84 million, $81 million and $78 million for 2009, 2008 and 2007, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2010 and thereafter.

C. Guarantees

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2009, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included in the accompanying Consolidated Balance Sheets.

At December 31, 2009, we have issued guarantees and indemnifications of and for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses. At December 31, 2009, our estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $458 million, including $32 million at PEF. Related to the sales of businesses, the latest specified notice period extends until 2013 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications have no limitations as to time or maximum potential future payments. At December 31, 2009 and 2008, we had recorded liabilities related to guarantees and indemnifications to third parties of approximately $34 million and $61 million, respectively. During the year ended December 31, 2009, our indemnification liability for certain legal matters made in connection with the sale of businesses decreased by approximately $16 million as a result of a legal verdict discussed under "Synthetic Fuels Matters" in Note 22D. 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. At December 31, 2009, all of PEC's environmental compliance projects under the first phase of Clean Smokestacks Act emission reductions, including projects at the Mayo and Roxboro Plants, had been placed in service. PEC estimates its remaining exposure under the indemnification is not material (See Note 21B). During the year ended December 31, 2009, PEC accrued approximately $2 million and spent approximately $12 million that exceeded the joint owner limit. During the year ended December 31, 2008, PEC made no additional accruals and spent approximately $20 million that exceeded the joint owner limit. 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. Approximately 60 cases involving the government's actions in connection with spent nuclear fuel are currently pending in the Court of Federal Claims. The Utilities have asserted nearly $91 million in damages incurred between January 31, 1998, and December 31, 2005, the time period set by the court for damages in this case. The Utilities will be free to file subsequent damage claims as they incur additional costs.

A trial was held in November 2007, and closing arguments were presented on April 4, 2008. On May 19, 2008, the Utilities received a ruling from the United States Court of Federal Claims awarding $83 million in the claim against the DOE for failure to abide by a contract for federal disposition of spent nuclear fuel. The United States Department of Justice requested that the Trial Court reconsider its ruling. The Trial Court did reconsider its ruling and reduced the damage award by an immaterial amount. On August 15, 2008, the Department of Justice appealed the United States Court of Federal Claims ruling to the D.C. Court of Appeals. Oral arguments were held on May 4, 2009. On July 21, 2009, the D.C. Court of Appeals vacated and remanded the calculation of damages back to the Trial Court but affirmed the portion of damages awarded that were directed to overhead costs and other indirect expenses. The Department of Justice requested a rehearing en banc but the D.C. Court of Appeals denied the motion on November 3, 2009. In the event that the Utilities recover damages in this matter, such recovery is not expected to have a material impact on the Utilities' results of operations given the anticipated regulatory and accounting treatment. However, the Utilities cannot predict the outcome of this matter.

SYNTHETIC FUELS MATTERS

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates arising out of an Asset Purchase Agreement dated as of October 19, 1999, and amended as of August 23, 2000, (the Asset Purchase Agreement) by and among U.S. Global, LLC (Global); Earthco; certain affiliates of Earthco; EFC Synfuel LLC (which was owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (currently named Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to the Asset Purchase Agreement. In a case filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case), Global had requested an unspecified amount of compensatory damages, as well as declaratory relief. Global asserted (1) that pursuant to the Asset Purchase Agreement, it was entitled to an interest in two synthetic fuels facilities previously owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities, (2) that it was entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities. As a result of the expiration of the Section 29 tax credit program on December 31, 2007, all of our synthetic fuels businesses were abandoned and we reclassified our synthetic fuels businesses as discontinued operations (See Note 3A).

The jury awarded Global $78 million. On October 23, 2009, Global filed a motion to assess prejudgment interest on the award. On November 20, 2009, the court granted the motion and assessed $55 million in prejudgment interest and entered judgment in favor of Global in a total amount of $133 million. During the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations (See Note 3A), which was net of a previously recorded indemnification liability of $16 million. In December 2009, we made a $154 million payment, which represents payment of the total judgment and a required premium equivalent to two years of interest, to the Broward County Clerk of Court bond account. On December 16, 2009, we filed notice of appeal. We cannot predict the outcome of this matter.

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

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss, but stayed the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress Affiliates appealed the superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal. Based upon the resolution of the Florida Global Case, we anticipate dismissal of the North Carolina Global Case.

In December 2006, we reached agreement with Global to settle an additional claim in the Florida Global Case 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.

NOTICE OF VIOLATION

On April 29, 2009, the EPA issued a notice of violation and opportunity to show cause with respect to a 16,000-gallon oil spill at one of PEC's substations in 2007. The notice of violation did not include specified sanctions sought. Subsequently, the EPA notified PEC that the agency is seeking monetary sanctions that are de minimus to our results of operations or financial condition. Discussions between PEC and the EPA are ongoing. We cannot predict the outcome of this matter.

FLORIDA NUCLEAR COST RECOVERY

On February 8, 2010, a lawsuit was filed against PEF in state circuit court in Sumter County, Fla., alleging that the Florida nuclear cost-recovery statute (Section 366.93, Florida Statutes) violates the Florida Constitution, and seeking a refund of all monies collected by PEF pursuant to that statute with interest. The complaint also requests that the court grant class action status to the plaintiffs. PEF believes the lawsuit is without merit and will defend against it. We cannot predict the outcome of this matter.

OTHER LITIGATION MATTERS

We are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, we have made accruals and disclosures to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

23. CONDENSED CONSOLIDATING STATEMENTS

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

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing $300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities) and using the proceeds thereof to purchase from Funding Corp. $300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039 (Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes Guarantee (as discussed below). Funding Corp. is a wholly owned subsidiary of Florida Progress and was formed for the sole purpose of providing financing to Florida Progress and its subsidiaries. Funding Corp. does not engage in business activities other than such financing and has no independent operations. Since 1999, Florida Progress has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes (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 annual 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. At December 31, 2009, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional and are in addition to the joint and several, full and unconditional, guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances and, as disclosed in Note 11B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a variable-interest entity of which we are not the primary beneficiary. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In these condensed consolidating statements, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the consolidated financial results of Florida Progress only. The Non-guarantor Subsidiaries column includes the consolidated financial results of all non-guarantor subsidiaries, which is primarily comprised of our wholly owned subsidiary PEC. The Other column includes elimination entries for all intercompany transactions and other consolidation adjustments. All applicable corporate expenses have been allocated appropriately among the guarantor and non-guarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the Subsidiary Guarantor or other non-guarantor subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2009 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$5,259	$4,626	$–	$9,885
Affiliate revenues	–	–	235	(235)	–
Total operating revenues	–	5,259	4,861	(235)	9,885
Operating expenses					
Fuel used in electric generation	–	2,072	1,680	–	3,752
Purchased power	–	682	229	–	911
Operation and maintenance	8	839	1,269	(222)	1,894
Depreciation, amortization and accretion	–	502	484	–	986
Taxes other than on income	–	347	216	(6)	557
Other	–	13	–	–	13
Total operating expenses	8	4,455	3,878	(228)	8,113
Operating (loss) income	(8)	804	983	(7)	1,772
Other income (expense)					
Interest income	10	5	9	(10)	14
Allowance for equity funds used during construction	–	91	33	–	124
Other, net	18	6	(22)	4	6
Total other income (expense), net	28	102	20	(6)	144
Interest charges					
Interest charges	233	280	215	(10)	718
Allowance for borrowed funds used during construction	–	(27)	(12)	–	(39)
Total interest charges, net	233	253	203	(10)	679
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(213)	653	800	(3)	1,237
Income tax (benefit) expense	(93)	200	286	4	397
Equity in earnings of consolidated subsidiaries	875	–	–	(875)	–
Income (loss) from continuing operations	755	453	514	(882)	840
Discontinued operations, net of tax	2	(43)	(38)	–	(79)
Net income (loss)	757	410	476	(882)	761
Net (income) loss attributable to noncontrolling interests, net of tax	–	(3)	2	(3)	(4)
Net income (loss) attributable to controlling interests	$757	$407	$478	$(885)	$757

CONDENSED CONSOLIDATING STATEMENT OF INCOME

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

CONDENSED CONSOLIDATING STATEMENT OF INCOME

Year ended December 31, 2007 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$–	$4,768	$4,385	$–	$9,153
Affiliate revenues	–	–	391	(391)	–
Total operating revenues	–	4,768	4,776	(391)	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	1,369	(371)	1,842
Depreciation, amortization and accretion	–	369	536	–	905
Taxes other than on income	–	309	202	(10)	501
Other	–	20	98	(88)	30
Total operating expenses	10	4,178	3,888	(469)	7,607
Operating (loss) income	(10)	590	888	78	1,546
Other income (expense)					
Interest income	27	8	24	(25)	34
Allowance for equity funds used during construction	–	41	10	–	51
Other, net	–	(2)	(9)	4	(7)
Total other income (expense), net	27	47	25	(21)	78
Interest charges					
Interest charges	203	210	219	(27)	605
Allowance for borrowed funds used during construction	–	(12)	(5)	–	(17)
Total interest charges, net	203	198	214	(27)	588
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(186)	439	699	84	1,036
Income tax (benefit) expense	(79)	117	297	(1)	334
Equity in earnings of consolidated subsidiaries	596	–	–	(596)	–
Income (loss) from continuing operations	489	322	402	(511)	702
Discontinued operations, net of tax	15	13	(137)	(97)	(206)
Net income (loss)	504	335	265	(608)	496
Net loss attributable to noncontrolling interests, net of tax	–	8	–	–	8
Net income (loss) attributable to controlling interests	$504	$343	$265	$(608)	$504

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2009 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$–	$9,733	$9,886	$114	$19,733
Current assets					
Cash and cash equivalents	606	72	47	–	725
Notes receivable from affiliated companies	30	46	303	(379)	–
Regulatory assets	–	54	88	–	142
Derivative collateral posted	–	139	7	–	146
Income taxes receivable	5	97	50	(7)	145
Prepayments and other current assets	14	1,158	1,377	(176)	2,373
Total current assets	655	1,566	1,872	(562)	3,531
Deferred debits and other assets					
Investment in consolidated subsidiaries	13,348	–	–	(13,348)	–
Regulatory assets	–	1,307	873	(1)	2,179
Goodwill	–	–	–	3,655	3,655
Nuclear decommissioning trust funds	–	496	871	–	1,367
Other assets and deferred debits	166	202	923	(520)	771
Total deferred debits and other assets	13,514	2,005	2,667	(10,214)	7,972
Total assets	$14,169	$13,304	$14,425	$(10,662)	$31,236
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$9,449	$4,590	$5,085	$(9,675)	$9,449
Noncontrolling interests	–	3	3	–	6
Total equity	9,449	4,593	5,088	(9,675)	9,455
Preferred stock of subsidiaries	–	34	59	–	93
Long-term debt, affiliate	–	309	115	(152)	272
Long-term debt, net	4,193	3,883	3,703	–	11,779
Total capitalization	13,642	8,819	8,965	(9,827)	21,599
Current liabilities					
Current portion of long-term debt	100	300	6	–	406
Short-term debt	140	–	–	–	140
Notes payable to affiliated companies	–	376	3	(379)	–
Derivative liabilities	–	161	29	–	190
Other current liabilities	261	941	902	(182)	1,922
Total current liabilities	501	1,778	940	(561)	2,658
Deferred credits and other liabilities					
Noncurrent income tax liabilities	–	320	1,258	(382)	1,196
Regulatory liabilities	–	1,103	1,293	114	2,510
Other liabilities and deferred credits	26	1,284	1,969	(6)	3,273
Total deferred credits and other liabilities	26	2,707	4,520	(274)	6,979
Total capitalization and liabilities	$14,169	$13,304	$14,425	$(10,662)	$31,236

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2008 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$–	$8,790	$9,385	$118	$18,293
Current assets					
Cash and cash equivalents	88	73	19	–	180
Notes receivable from affiliated companies	34	44	131	(209)	–
Regulatory assets	–	326	207	–	533
Derivative collateral posted	–	335	18	–	353
Income taxes receivable	34	56	104	–	194
Prepayments and other current assets	14	1,082	1,336	(172)	2,260
Total current assets	170	1,916	1,815	(381)	3,520
Deferred debits and other assets					
Investment in consolidated subsidiaries	11,924	–	–	(11,924)	–
Regulatory assets	–	1,324	1,243	–	2,567
Goodwill	–	–	–	3,655	3,655
Nuclear decommissioning trust funds	–	417	672	–	1,089
Other assets and deferred debits	155	196	953	(555)	749
Total deferred debits and other assets	12,079	1,937	2,868	(8,824)	8,060
Total assets	$12,249	$12,643	$14,068	$(9,087)	$29,873
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$8,687	$3,519	$4,729	$(8,248)	$8,687
Noncontrolling interests	–	3	4	(1)	6
Total equity	8,687	3,522	4,733	(8,249)	8,693
Preferred stock of subsidiaries	–	34	59	–	93
Long-term debt, affiliate	–	309	115	(152)	272
Long-term debt, net	2,696	4,182	3,509	–	10,387
Total capitalization	11,383	8,047	8,416	(8,401)	19,445
Current liabilities					
Short-term debt	569	371	110	–	1,050
Notes payable to affiliated companies	–	206	3	(209)	–
Derivative liabilities	31	380	84	(2)	493
Other current liabilities	220	964	930	(171)	1,943
Total current liabilities	820	1,921	1,127	(382)	3,486
Deferred credits and other liabilities					
Noncurrent income tax liabilities	1	118	1,111	(412)	818
Regulatory liabilities	–	1,076	987	118	2,181
Other liabilities and deferred credits	45	1,481	2,427	(10)	3,943
Total deferred credits and other liabilities	46	2,675	4,525	(304)	6,942
Total capitalization and liabilities	$12,249	$12,643	$14,068	$(9,087)	$29,873

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2009 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$108	$1,079	$1,282	$(198)	$2,271
Investing activities					
Gross property additions	–	(1,449)	(858)	12	(2,295)
Nuclear fuel additions	–	(78)	(122)	–	(200)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	–	1	–	1
Proceeds from sales of assets to affiliated companies	–	–	11	(11)	–
Purchases of available-for-sale securities and other investments	–	(1,548)	(802)	–	(2,350)
Proceeds from available-for-sale securities and other investments	–	1,558	756	–	2,314
Changes in advances to affiliated companies	4	(2)	(172)	170	–
Contributions to consolidated subsidiaries	(688)	–	–	688	–
Return of investment in consolidated subsidiaries	12	–	–	(12)	–
Other investing activities	–	–	(2)	–	(2)
Net cash (used) provided by investing activities	(672)	(1,519)	(1,188)	847	(2,532)
Financing activities					
Issuance of common stock	623	–	–	–	623
Dividends paid on common stock	(693)	–	–	–	(693)
Dividends paid to parent	–	(1)	(200)	201	–
Dividends paid to parent in excess of retained earnings	–	–	(12)	12	–
Payments of short-term debt with original maturities greater than 90 days	(29)	–	–	–	(29)
Net decrease in short-term debt	(500)	(371)	(110)	–	(981)
Proceeds from issuance of long-term debt, net	1,683	–	595	–	2,278
Retirement of long-term debt	–	–	(400)	–	(400)
Cash distributions to noncontrolling interests	–	(3)	–	(3)	(6)
Changes in advances from affiliated companies	–	170	–	(170)	–
Contributions from parent	–	653	49	(702)	–
Other financing activities	(2)	(9)	12	13	14
Net cash provided (used) by financing activities	1,082	439	(66)	(649)	806
Net increase (decrease) in cash and cash equivalents	518	(1)	28	–	545
Cash and cash equivalents at beginning of year	88	73	19	–	180
Cash and cash equivalents at end of year	$606	$72	$47	$–	$725

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2008 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash (used) provided by operating activities	$(90)	$221	$1,114	($27)	$1,218
Investing activities					
Gross property additions	–	(1,553)	(794)	14	(2,333)
Nuclear fuel additions	–	(43)	(179)	–	(222)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	59	13	–	72
Proceeds from sales of assets to affiliated companies	–	12	–	(12)	–
Purchases of available-for-sale securities and other investments	(7)	(783)	(800)	–	(1,590)
Proceeds from available-for-sale securities and other investments	–	788	746	–	1,534
Changes in advances to affiliated companies	123	105	8	(236)	–
Contributions to consolidated subsidiaries	(101)	–	–	101	–
Return of investment in consolidated subsidiaries	20	10	–	(30)	–
Other investing activities	–	(2)	–	–	(2)
Net cash provided (used) by investing activities	35	(1,407)	(1,006)	(163)	(2,541)
Financing activities					
Issuance of common stock	132	–	–	–	132
Dividends paid on common stock	(642)	–	–	–	(642)
Dividends paid to parent	–	(33)	–	33	–
Dividends paid to parent in excess of retained earnings	–	–	(20)	20	–
Payments of short-term debt with original maturities greater than 90 days	(176)	–	–	–	(176)
Proceeds from issuance of short-term debt with original maturities greater than 90 days	29	–	–	–	29
Net increase in short-term debt	615	371	110	–	1,096
Proceeds from issuance of long-term debt, net	–	1,475	322	–	1,797
Retirement of long-term debt	–	(577)	(300)	–	(877)
Cash distributions to noncontrolling interests	–	(85)	(10)	10	(85)
Changes in advances from affiliated companies	–	(21)	(215)	236	–
Contributions from parent	–	85	29	(114)	–
Other financing activities	–	1	(32)	5	(26)
Net cash (used) provided by financing activities	(42)	1,216	(116)	190	1,248
Net (decrease) increase in cash and cash equivalents	(97)	30	(8)	–	(75)
Cash and cash equivalents at beginning of year	185	43	27	–	255
Cash and cash equivalents at end of year	$88	$73	$19	$–	$180

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Year ended December 31, 2007 *(in millions)*	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided (used) by operating activities	$76	$489	$835	$(148)	$1,252
Investing activities					
Gross property additions	–	(1,218)	(757)	2	(1,973)
Nuclear fuel additions	–	(44)	(184)	–	(228)
Proceeds from sales of discontinued operations and other assets, net of cash divested	–	51	625	(1)	675
Purchases of available-for-sale securities and other investments	–	(640)	(773)	–	(1,413)
Proceeds from available-for-sale securities and other investments	21	640	791	–	1,452
Changes in advances to affiliated companies	(99)	(112)	(79)	290	–
Return of investment in consolidated subsidiaries	340	–	–	(340)	–
Other investing activities	(31)	32	(7)	36	30
Net cash provided (used) by investing activities	231	(1,291)	(384)	(13)	(1,457)
Financing activities					
Issuance of common stock	151	–	–	–	151
Dividends paid on common stock	(627)	–	–	–	(627)
Dividends paid to parent	–	(10)	(483)	493	–
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)
Cash distributions to noncontrolling interests	–	(10)	–	–	(10)
Changes in advances from affiliated companies	–	151	129	(280)	–
Contributions from parent	–	10	44	(54)	–
Other financing activities	–	49	14	2	65
Net cash (used) provided by financing activities	(275)	805	(496)	161	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

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data was as follows:

(in millions except per share data)	First	Second	Third	Fourth
2009				
Operating revenues	$2,442	$2,312	$2,824	$2,307
Operating income	393	379	676	324
Income from continuing operations	183	175	350	132
Net income	183	174	248	156
Net income attributable to controlling interests	182	174	247	154
Common stock data				
Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	0.66	0.62	1.24	0.46
Net income attributable to controlling interests	0.66	0.62	0.88	0.55
Dividends declared per common share	0.620	0.620	0.620	0.620
Market price per share – High	40.85	38.20	40.05	42.20
– Low	31.35	33.50	35.97	36.67
2008[a]				
Operating revenues	$2,066	$2,244	$2,696	$2,161
Operating income	365	406	591	321
Income from continuing operations	153	200	309	116
Net income	214	205	310	107
Net income attributable to controlling interests	209	205	309	107
Common stock data				
Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	0.57	0.76	1.18	0.44
Net income attributable to controlling interests	0.80	0.78	1.18	0.41
Dividends declared per common share	0.615	0.615	0.615	0.620
Market price per share – High	49.16	43.58	45.52	45.60
– Low	40.54	41.00	40.11	32.60

[a] Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).

In the opinion of management, all adjustments necessary to fairly present amounts shown for interim periods have been made. Results of operations for an interim period may not give a true indication of results for the year. Typically, weather conditions in our service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to our customers. As a result, our overall operating results may fluctuate substantially on a seasonal basis. During the fourth quarter of 2009, we recorded a cumulative prior period adjustment related to certain employee life insurance benefits. The impact of this adjustment decreased total other income, net, by $16 million and decreased net income attributable to controlling interests by $10 million. The prior period adjustment is not material to previously issued or current period financial statements.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (UNAUDITED)

Years ended December 31 *(in millions except per share data)*	2009	2008[a]	2007[a]	2006[a]	2005[a]
Operating results					
Operating revenues	$9,885	$9,167	$9,153	$8,724	$7,948
Income from continuing operations before cumulative effect of changes in accounting principles, net of tax	840	778	702	567	527
Net income	761	836	496	620	668
Net income attributable to controlling interests	757	830	504	571	697
Per share data[b]					
Basic and diluted earnings					
Income from continuing operations attributable to controlling interests, net of tax	$2.99	$2.95	$2.70	$2.19	$2.10
Net income attributable to controlling interests	2.71	3.17	1.96	2.27	2.80
Assets	$31,236	$29,873	$26,338	$25,832	$27,083
Capitalization and debt					
Common stock equity	$9,449	$8,687	$8,395	$8,259	$8,011
Preferred stock of subsidiaries – not subject to mandatory redemption	93	93	93	93	93
Noncontrolling interest	6	6	84	10	36
Long-term debt, net[c]	12,051	10,659	8,737	8,835	10,446
Current portion of long-term debt	406	–	877	324	513
Short-term debt	140	1,050	201	–	175
Capital lease obligations	231	239	247	72	18
Total capitalization and debt	$22,376	$20,734	$18,634	$17,593	$19,292
Other financial data					
Return on average common stock equity (percent)	8.13	9.59	5.97	7.05	8.92
Ratio of earnings to fixed charges	2.66	2.66	2.62	2.35	2.33
Number of common shareholders of record	53,922	55,919	58,991	64,899	67,638
Book value per common share	$33.53	$32.97	$32.41	$32.53	$32.16
Dividends declared per common share	$2.48	$2.47	$2.45	$2.43	$2.38
Energy supply (millions of kilowatt-hours)					
Generated					
Steam	40,420	46,771	51,163	48,770	52,306
Nuclear	29,412	30,565	30,336	30,602	30,120
Combustion turbines/combined cycle	21,254	15,557	13,319	11,857	11,349
Hydro	651	429	415	594	749
Purchased	11,996	14,956	14,994	14,664	14,566
Total energy supply (Company share)	103,733	108,278	110,227	106,487	109,090
Joint-owner share[d]	5,500	5,780	5,351	5,224	5,388
Total system energy supply	109,233	114,058	115,578	111,711	114,478

[a] Balances have been restated for the adoption of new accounting guidance, which modified the financial statement presentation of subsidiaries that are less than wholly owned (See Note 2).

[b] Balances have been restated for the adoption of new accounting guidance, which redefined which securities and non-vested share-based compensation awards are considered to participate in our current earnings (See Note 2).

[c] Includes long-term debt to affiliated trust of $272 million at December 31, 2009 and 2008, $271 million at December 31, 2007 and 2006 and $270 million at December 31, 2005 (See Note 23).

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

Progress Energy's management uses Ongoing Earnings per share to evaluate the operations of the company and to establish goals for management and employees. Management believes this non-GAAP measure is appropriate for understanding the business and assessing our potential future performance, because excluded items are limited to those that we believe are not representative of our fundamental core earnings. Ongoing Earnings as presented here may not be comparable to similarly titled measures used by other companies.

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

	2009	2008[a]	2007[a]
Ongoing Earnings per share	**$3.03**	$2.96	$2.71
CVO mark-to-market	**0.07**	–	(0.01)
Impairment	**(0.01)**	–	–
Plant retirement charge	**(0.06)**	–	–
Cumulative prior period adjustment related to certain employee life insurance benefits	**(0.04)**	–	–
Valuation allowance and related net operating loss carry forward	**–**	(0.01)	–
Discontinued operations	**(0.28)**	0.22	(0.74)
Reported GAAP earnings per share	**$2.71**	$3.17	$1.96
Shares outstanding (millions)	**279**	262	257

[a] Previously reported 2008 and 2007 earnings per share have been restated to reflect the adoption of new accounting guidance that changed the calculation of the number of average common shares outstanding.

CVO Mark-to-Market

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

Impairment

The company has recorded impairments of certain investments of its Affordable Housing portfolio. Management believes this adjustment is not representative of the company's fundamental core earnings.

Plant Retirement Charges

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

Cumulative Prior Period Adjustment Related to Certain Employee Life Insurance Benefits

In the fourth quarter of 2009, PEC recorded a cumulative prior period adjustment related to certain employee life insurance benefits. Management believes this adjustment is not representative of the company's fundamental core earnings. The prior period adjustment was not material to previously issued or current period financial statements.

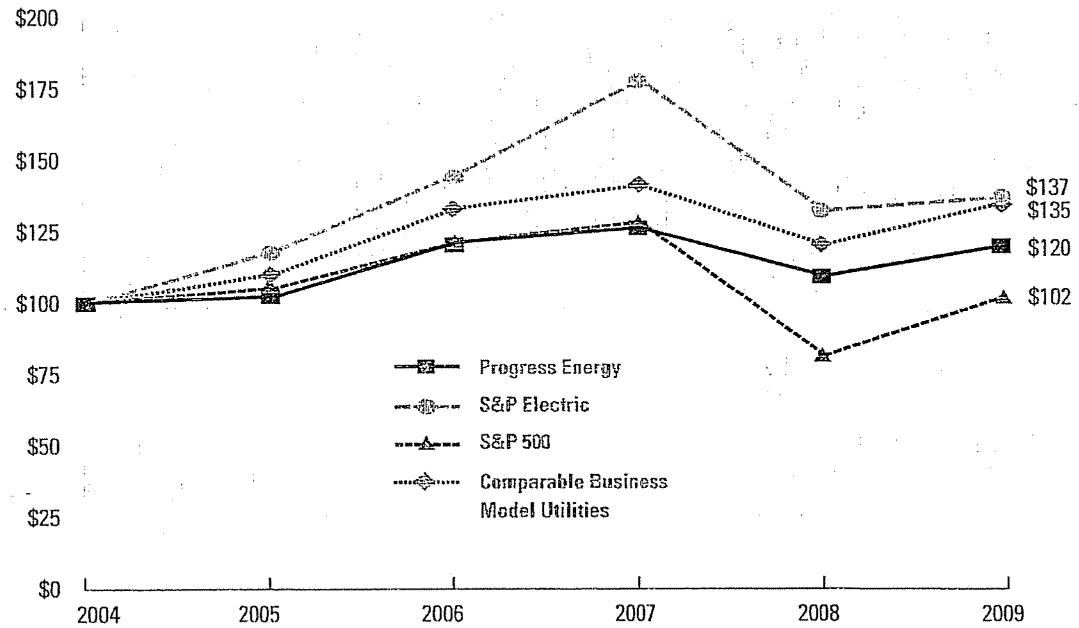
Valuation Allowance and Related Net Operating Loss Carry Forward

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

Discontinued Operations

The company has reduced its business risk by exiting nonregulated businesses to focus on the core operations of the Utilities. Due to disposition of these assets, management does not view this activity as representative of the company's fundamental core earnings.

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



Measurement Period (Fiscal Year Covered)	2004	2005	2006	2007	2008	2009
Progress Energy, Inc.	$100	$102	$121	$126	$109	$120
S&P 500 Index	100	105	121	128	81	102
Comparable Business Model Utilities	100	110	133	141	120	135
S&P Electric Index	100	118	145	178	132	137

*$100 invested on 12/31/2004 in Stock or Index. Including reinvestment of dividends. Fiscal year ended December 31.

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

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

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

SHAREHOLDER INFORMATION

Notice of Annual Meeting

Progress Energy's 2010 annual meeting of shareholders will be held May 12, 2010, at 10 a.m. at the Progress Energy Center for the Performing Arts in Raleigh, N.C. A formal notice of the meeting will be mailed to shareholders in late March.

Transfer Agent and Registrar Mailing Address

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

Shareholder Information and Inquiries

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

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

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

Stock Listings

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

Shareholder Programs

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

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

Securities Analyst Inquiries

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

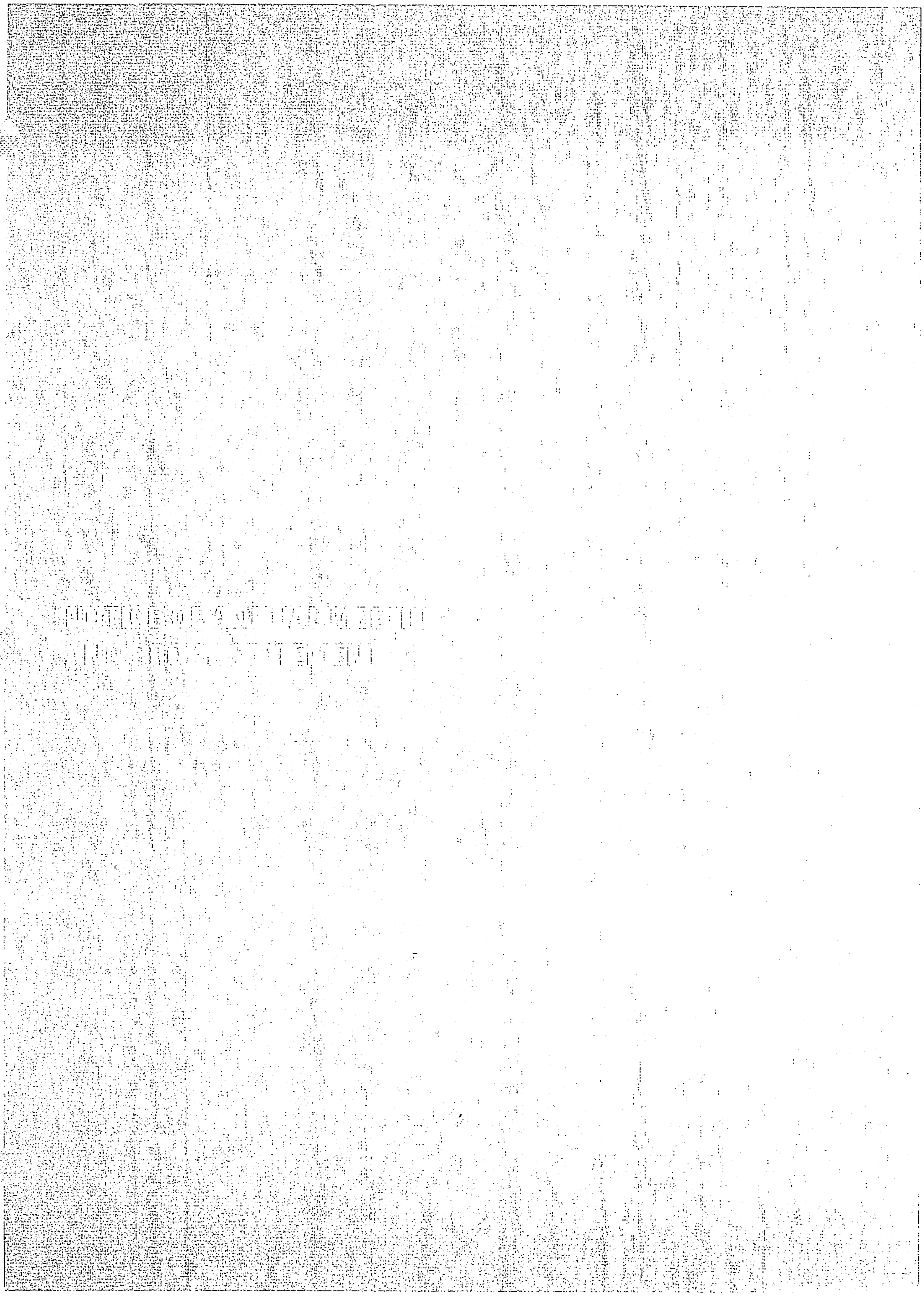
Additional Information

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

This annual report is submitted for shareholders' information and is available for delivery to shareholders in connection with our 2010 annual meeting of shareholders. It is not intended for use in connection with any sale or purchase of, or any offer or solicitation of offers to buy or sell, securities.

Cautionary Statement

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



Progress Energy

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

March 31, 2010

Dear Shareholder:

I am pleased to invite you to attend the 2010 Annual Meeting of the Shareholders of Progress Energy, Inc. The meeting will be held at 10:00 a.m. on May 12, 2010, at the Progress Energy Center for the Performing Arts, 2 East South Street, Raleigh, North Carolina.

As described in the accompanying Notice of Annual Meeting of Shareholders and Proxy Statement, the matters scheduled to be acted upon at the meeting for Progress Energy, Inc. are the election of directors, the ratification of the selection of the independent registered public accounting firm for Progress Energy, Inc., and a shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards.

We are pleased to take advantage of the Securities and Exchange Commission rules that permit companies to electronically deliver proxy materials to their shareholders. This process allows us to provide our shareholders with the information they need while lowering printing and mailing costs and more efficiently complying with our obligations under the securities laws. On or about March 31, 2010, we mailed to our registered and beneficial shareholders a Notice containing instructions on how to access our combined Proxy Statement and Annual Report and vote online.

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

I am delighted that you have chosen to invest in Progress Energy, Inc., and look forward to seeing you at the meeting. On behalf of the management and directors of Progress Energy, Inc., thank you for your continued support and confidence in 2010.

Sincerely,

William D. Johnson

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

VOTING YOUR PROXY IS IMPORTANT

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

If you received this Proxy Statement by mail, please promptly **SIGN, DATE and RETURN** the enclosed proxy card or **VOTE BY TELEPHONE** in accordance with the instructions on the enclosed proxy card so that as many shares as possible will be represented at the Annual Meeting. A self-addressed envelope, which requires no postage if mailed in the United States, is enclosed for your convenience.

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

NOTICE OF THE ANNUAL MEETING OF SHAREHOLDERS
TO BE HELD ON

MAY 12, 2010

The Annual Meeting of the Shareholders of Progress Energy, Inc. (the "Company") will be held at 10:00 a.m. on May 12, 2010, at the Progress Energy Center for the Performing Arts, 2 East South Street, Raleigh, North Carolina. The meeting will be held in order to:

(1) Elect fourteen (14) directors of the Company, each to serve a one-year term. The Board of Directors recommends a vote **FOR** each of the nominees for director.

(2) Ratify the selection of Deloitte & Touche LLP as the independent registered public accounting firm for the Company. The Board of Directors recommends a vote **FOR** the ratification of the selection of Deloitte & Touche LLP as the Company's independent registered public accounting firm.

(3) Vote on a shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards. The Board of Directors recommends a vote **AGAINST** the shareholder proposal.

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

All holders of the Company's Common Stock of record at the close of business on March 5, 2010, are entitled to attend the meeting and to vote. The stock transfer books will remain open.

By order of the Board of Directors

JOHN R. MCARTHUR
Executive Vice President
and Corporate Secretary

Raleigh, North Carolina
March 31, 2010

PROXY STATEMENT

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

PROXY STATEMENT
GENERAL

This Proxy Statement is furnished in connection with the solicitation by the Board of Directors (at times referred to as the "Board") of proxies to be used at the Annual Meeting of Shareholders. That meeting will be held at 10:00 a.m. on May 12, 2010, at the Progress Energy Center for the Performing Arts, 2 East South Street, Raleigh, North Carolina. (For directions to the meeting location, please see the map included at the end of this Proxy Statement.) Throughout this Proxy Statement, Progress Energy, Inc. is at times referred to as "Progress Energy," "we," "our" or "us." This Proxy Statement and form of proxy were first sent to shareholders on or about March 31, 2010.

An audio Webcast of the Annual Meeting of Shareholders will be available online in Windows Media Player format at *www.progress-energy.com/investor*. The Webcast will be archived on the site for three months following the date of the meeting.

Copies of our Annual Report on Form 10-K for the year ended December 31, 2009, including financial statements and schedules, are available upon written request, without charge, to the persons whose proxies are solicited. Any exhibit to the Form 10-K is also available upon written request at a reasonable charge for copying and mailing. Written requests should be made to Mr. Thomas R. Sullivan, Treasurer, Progress Energy, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551. Our Form 10-K is also available through the Securities and Exchange Commission's (the "SEC") Web site at *www.sec.gov* or through our Web site at *www.progress-energy.com/investor*. The contents of these Web sites are not, and shall not be deemed to be, a part of this Proxy Statement or proxy solicitation materials.

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

We have adopted a procedure approved by the SEC called "householding." Under this procedure, shareholders of record who have the same address and last name and do not participate in the electronic delivery of proxy materials will receive only one copy of our Proxy Statement and Annual Report, unless one or more of the shareholders at that address notifies us that they wish to continue receiving individual copies. We believe this procedure provides greater convenience to our shareholders and saves money by reducing our printing and mailing costs and fees.

If you prefer to receive a separate copy of our combined Proxy Statement and Annual Report, please write to Shareholder Relations, Progress Energy, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551 or telephone our Shareholder Relations Section at 919-546-3014, and we will promptly send you a separate copy. If you are currently receiving multiple copies of the Proxy Statement and Annual Report at your address and would prefer that a single copy of each be delivered there, you may contact us at the address or telephone number provided in this paragraph.

PROXIES

The accompanying proxy is solicited by our Board of Directors, and we will bear the entire cost of solicitation. We expect to solicit proxies primarily by telephone, mail, e-mail or other electronic media or personally by our and our subsidiaries' officers and employees, who will not be specially compensated for such services. In addition, the Company will engage Morrow & Co., LLC, if necessary, to assist in the solicitation of proxies on behalf of the Board. It is anticipated that the cost of the solicitation service to the Company will be approximately $35,000 plus out-of-pocket expenses.

You may vote shares either in person or by duly authorized proxy. In addition, you may vote your shares by telephone or via the Internet by following the instructions provided on the enclosed proxy card. Please be aware that if you vote via the Internet, you may incur costs such as telecommunication and Internet access charges for which you will be responsible. The Internet and telephone voting facilities for shareholders of record will close at 12:01 a.m. E.D.T. on the morning of the meeting. Any shareholder who has executed a proxy and attends the meeting may elect to vote in person rather than by proxy. You may revoke any proxy given by you in response to this solicitation at any time before the proxy is exercised by (i) delivering a written notice of revocation to our Corporate Secretary, (ii) timely filing, with our Corporate Secretary, a subsequently dated, properly executed proxy, or (iii) attending the Annual Meeting and electing to vote in person. Your attendance at the Annual Meeting, by itself, will not constitute a revocation of a proxy. If you vote by telephone or via the Internet, you may also revoke your vote by any of the three methods noted above, or you may change your vote by voting again by telephone or via the Internet. If you decide to vote by completing and mailing the enclosed proxy card, you should retain a copy of certain identifying information found on the proxy card in the event that you decide later to change or revoke your proxy by accessing the Internet. You should address any written notices of proxy revocation to: Progress Energy, Inc., P.O. Box 1551, Raleigh, North Carolina 27602-1551, Attention: Corporate Secretary.

All shares represented by effective proxies received by the Company at or before the Annual Meeting, and not revoked before they are exercised, will be voted in the manner specified therein. Executed proxies that do not contain voting instructions will be voted **"FOR"** the election of all directors as set forth in this Proxy Statement; **"FOR"** the ratification of the selection of Deloitte & Touche LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2010, as set forth in this Proxy Statement; and **"AGAINST"** the shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards as set forth in this Proxy Statement. Proxies will be voted at the discretion of the named proxies on any other business properly brought before the meeting.

If you are a participant in our 401(k) Savings & Stock Ownership Plan, shares allocated to your Plan account will be voted by the Trustee only if you execute and return your proxy, or vote by telephone or via the Internet. Plan participants must provide voting instructions on or before 11:59 p.m. E.D.T. on May 9, 2010. Company stock remaining in the ESOP Stock Suspense Account that has not been allocated to employee accounts shall be voted by the Trustee in the same proportion as shares voted by participants in the 401(k) Plan.

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

Special Note for Shares Held in "Street Name"

If your shares are held by a brokerage firm, bank or other nominee (i.e., in "street name"), you will receive directions from your nominee that you must follow in order to have your shares voted. "Street name" shareholders who wish to vote in person at the meeting will need to obtain a special proxy form from the brokerage firm, bank or other nominee that holds their shares of record. You should contact your brokerage firm, bank or other nominee for details regarding how you may obtain this special proxy form.

If your shares are held in "street name" and you do not give instructions as to how you want your shares voted (a "nonvote"), the brokerage firm, bank or other nominee who holds Progress Energy shares on your behalf may vote the shares at its discretion with regard to "routine" matters. However, such brokerage firm, bank or other nominee is not required to vote the shares of Common Stock, and therefore these unvoted shares would be counted as "broker nonvotes."

With respect to "routine" matters, such as the ratification of the selection of the independent registered public accounting firm, a brokerage firm, bank or other nominee has authority (but is not required) under the rules governing self-regulatory organizations (the "SRO rules"), including the New York Stock Exchange ("NYSE"), to vote its clients' shares if the clients do not provide instructions. When a brokerage firm, bank or other nominee votes its clients' Common Stock shares on routine matters without receiving voting instructions, these shares are counted both for establishing a quorum to conduct business at the meeting and in determining the number of shares voted **"FOR"** or **"AGAINST"** such routine matters. The NYSE recently amended its rules to make the election of directors a "nonroutine" matter.

With respect to "nonroutine" matters, including the election of directors and shareholder proposals, a brokerage firm, bank or other nominee is not permitted under the SRO rules to vote its clients' shares if the clients do not specifically instruct their brokerage firm, bank or other nominee on how to vote their shares. The brokerage firm, bank or other nominee will so note on the vote card, and this constitutes a "broker nonvote." "Broker nonvotes" will be counted for purposes of establishing a quorum to conduct business at the meeting but not for determining the number of shares voted **"FOR," "AGAINST"** or **"ABSTAINING"** from such nonroutine matters. At the 2010 Annual Meeting of Shareholders, two nonroutine matters, the election of 14 directors of the Company with terms expiring in 2011 and a shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards, will be presented for a vote.

Accordingly, if you do not vote your proxy, your brokerage firm, bank or other nominee may either: (i) vote your shares on routine matters and cast a "broker nonvote" on nonroutine matters, or (ii) leave your shares unvoted altogether. Therefore, we encourage you to provide instructions to your brokerage firm, bank or other nominee by voting your proxy. This action ensures that your shares and voting preferences will be fully represented at the meeting.

VOTING SECURITIES

Our directors have fixed March 5, 2010, as the record date for shareholders entitled to vote at the Annual Meeting. Only holders of our Common Stock of record at the close of business on that date are entitled to notice of and to vote at the Annual Meeting. Each share is entitled to one vote. As of March 5, 2010, there were outstanding 284,645,924 shares of Common Stock.

Consistent with state law and our By-Laws, the presence, in person or by proxy, of holders of at least a majority of the total number of Common Stock shares entitled to vote is necessary to constitute a quorum for the transaction of business at the Annual Meeting. Once a share of Common Stock is represented for any purpose at a meeting, it is deemed present for quorum purposes for the remainder of the meeting and any adjournment thereof, unless a new record date is or must be set in connection with any adjournment. Common Stock shares held of record by shareholders or their nominees who do not vote by proxy or attend the Annual Meeting in person will not be considered present or represented at the Annual Meeting and will not be counted in determining the presence of a quorum. Proxies that withhold authority or reflect abstentions or "broker nonvotes" will be counted for purposes of determining whether a quorum is present.

Pursuant to the provisions of our Articles of Incorporation, as amended effective May 10, 2006, a candidate for director will be elected upon receipt of at least a majority of the votes cast by the holders of Common Stock entitled to vote. Accordingly, assuming a quorum is present, each director shall be elected by a vote of the majority of the votes cast with respect to that director. A majority of the votes cast means that the number of shares voted **"FOR"** a director must exceed the number of votes cast **"AGAINST"** that director. Shares voting **"ABSTAIN"** and shares held in "street name" that are not voted in the election of directors will not be included in determining the number of votes cast.

Approval of the proposal to ratify the selection of our independent registered public accounting firm, and other matters properly brought before the Annual Meeting, if any, generally will require the affirmative vote of a majority of votes actually cast by holders of Common Stock entitled to vote. Assuming a quorum is present, the number of **"FOR"** votes cast at the meeting for this proposal must exceed the number of **"AGAINST"** votes cast at the meeting in order for this proposal to be approved. Abstentions from voting and "broker nonvotes" will not count as votes cast and will not have the effect of a "negative" vote with respect to any such matters.

Approval of the shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards will require the affirmative vote of a majority of the shares cast on the proposal provided that the total votes cast on the proposal represents over 50 percent of the shares entitled to vote on the proposal. Abstentions will not have the effect of "negative" votes with respect to the proposal. Shares held in "street name" that are not voted with respect to the shareholder proposal regarding the adoption of a "hold-into-retirement" policy for equity awards will not be included in determining the number of votes cast.

We will announce preliminary voting results at the Annual Meeting. We will publish the final results in a current report on Form 8-K within four (4) business days of the Annual Meeting. A copy of this Form 8-K may be obtained without charge by any of the means outlined above for obtaining a copy of our Annual Report on Form 10-K.

PROPOSAL 1—ELECTION OF DIRECTORS

The Company's amended By-Laws provide that the number of directors of the Company shall be between eleven (11) and fifteen (15). The amended By-Laws also provide for annual elections of each director. Directors will serve one-year terms upon election at the 2010 Annual Meeting of Shareholders.

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

Based on the report of the Governance Committee (see page 15), the Board of Directors nominates the following 14 nominees to serve as directors with terms expiring in 2011 and until their respective successors are elected and qualified: John D. Baker II, James E. Bostic, Jr., Harris E. DeLoach, Jr., James B. Hyler, Jr., William D. Johnson, Robert W. Jones, W. Steven Jones, Melquiades R. "Mel" Martinez, E. Marie McKee, John H. Mullin, III, Charles W. Pryor, Jr., Carlos A. Saladrigas, Theresa M. Stone, and Alfred C. Tollison, Jr.

There are no family relationships between any of the directors, any executive officers or nominees for director of the Company or its subsidiaries, and there is no arrangement or understanding between any director or director nominee and any other person pursuant to which the director or director nominee was selected.

The election of directors will be determined by a majority of the votes cast at the Annual Meeting at which a quorum is present. This means that the number of votes cast **"FOR"** a director must exceed the number of votes cast **"AGAINST"** that director in order for the director to be elected. Abstentions and broker nonvotes, if any, are not treated as votes cast and, therefore, will have no effect on the proposal to elect directors. Shareholders do not have cumulative voting rights in connection with the election of directors.

Valid proxies received pursuant to this solicitation will be voted in the manner specified. Where specifications are not made, the shares represented by the accompanying proxy will be voted **"FOR"** the election of each of the 14 nominees. Votes (other than abstentions) will be cast pursuant to the accompanying proxy for the election of the nominees listed above unless, by reason of death or other unexpected occurrence, one or more of such nominees shall not be available for election, in which event it is intended that such votes will be cast for such substitute nominee or nominees as may be determined by the persons named in such proxy. The Board of Directors has no reason to believe that any of the nominees listed above will not be available for election as a director.

The Board of Directors, acting through the Governance Committee, is responsible for assembling for shareholder consideration a group of nominees that, taken together, have the experience, qualifications, attributes and skills appropriate for functioning effectively as a board. The Governance Committee regularly reviews the composition of the Board in light of the Company's changing requirements and its assessment of the Board's performance. A discussion of the characteristics the Governance Committee looks for in evaluating director candidates appears in the "Governance Committee Process for Identifying and Evaluating Director Candidates" section on page 18 of this Proxy Statement.

The names of the 14 nominees for election to the Board of Directors, along with their ages, principal occupations or employment for the past five years, directorships of public companies held during the past five years, and disclosures regarding the specific experience, qualifications, attributes or skills that led the Board to conclude that such individual should serve on the Board, are set forth below. Messrs. John D. Baker II and Melquiades R. "Mel" Martinez, who were elected by the Board on September 17, 2009 and March 1, 2010, respectively, are directors standing for election to the Board by our shareholders for the first time. Mr. Baker was recommended to the Governance Committee by one of our non-management directors, and Mr. Martinez was recommended to the Governance Committee by William D. Johnson, who is our Chairman of the Board, President and Chief Executive Officer. (Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC") and Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF"), which are noted below, are wholly owned subsidiaries of the Company.) Information concerning the number of shares of our Common Stock beneficially owned, directly or indirectly, by all current directors appears on page 10 of this Proxy Statement.

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

Nominees for Election

JOHN D. BAKER II, age 61, is President and Chief Executive Officer of Patriot Transportation Holding, Inc., which is engaged in the transportation and real estate businesses. He has served in these positions since November 2007. Mr. Baker was President and Chief Executive Officer of Florida Rock Industries, Inc., a producer of cement, aggregates, concrete and concrete products from 1997 to 2007. As a lawyer and business executive with more than 35 years of experience in the construction materials and trucking industries, Mr. Baker brings business insight and expertise that will be valuable to the Company as it navigates a complex and changing business environment. Mr. Baker has served as a director of the Company since September 17, 2009 and is a member of the Board's Finance Committee and the Organization and Compensation Committee.

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

JAMES E. BOSTIC, JR., age 62, has been Managing Director of HEP & Associates, a business consulting firm, and a partner of Coleman Lew & Associates, an executive search consulting firm, since 2006. He retired as Executive Vice President of Georgia-Pacific Corporation, a manufacturer and distributor of tissue, paper, packaging, building products, pulp and related chemicals, in 2006. During his 20 years at Georgia-Pacific, Mr. Bostic served in various senior positions, including a stint as senior vice president—Environmental, Government Affairs and Communications. Over the years, Mr. Bostic's business background and his expertise on environmental and regulatory issues have been significant assets to the Company. That expertise will be particularly helpful as we continue to address new laws and regulations regarding global climate change and other environmental issues. Additionally, due to his years of service on the Board, Mr. Bostic has developed a keen understanding of how the Company operates, the key issues it faces, and its strategy for addressing those issues as it carries out its responsibilities to its shareholders and other stakeholders. He has served as a director of the Company since 2002. Mr. Bostic is a member of the Board's Audit and Corporate Performance Committee, the Nuclear Project Oversight Committee and the Operations and Nuclear Oversight Committee.

HARRIS E. DELOACH, JR., age 65, is Chairman, President and Chief Executive Officer of Sonoco Products Company, a manufacturer of paperboard and paper and plastic packaging products, since April 2005. He served as President and Chief Executive Officer of Sonoco Products from July 2000 to April 2005. Mr. DeLoach joined Sonoco Products in 1986 and has served in various management positions during his tenure there. Prior to joining Sonoco, Mr. DeLoach was in private law practice and served as an outside counsel to Sonoco for 15 years. Mr. DeLoach's legal background and years of experience leading a global packaging company will be valuable to the Company as it confronts a challenging economy and changing business environment. He has served as a director of the Company since 2006. Mr. DeLoach is Chair of the Board's Operations and Nuclear Oversight Committee and a member of the Executive Committee, the Governance Committee, the Nuclear Project Oversight Committee and the Organization and Compensation Committee.

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

JAMES B. HYLER, JR., age 62, retired as Vice Chairman and Chief Operating Officer of First Citizens Bank in 2008. He served in these positions from 1994 until 2008. Mr. Hyler was Chief Financial Officer of First Citizens Bank from 1980 to 1988, and served as President of First Citizens Bank from 1988 to 1994. Prior to joining First Citizens Bank, Mr. Hyler was an auditor with Ernst & Young for 10 years. Mr. Hyler has more than 37 years of experience in the financial services industry. Mr. Hyler's experience and accounting background have provided him with an understanding of the accounting principles used by the Company to prepare its financial statements and the ability to analyze such statements. His knowledge and experience in financial services and corporate finance will be valuable to the Company as our utilities continue to move forward with the expansion projects necessary to meet our customers' future energy needs reliably and affordably. Mr. Hyler has served as a director of the Company since 2008 and is a member of the Board's Finance Committee and the Organization and Compensation Committee.

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

WILLIAM D. JOHNSON, age 56, is Chairman, President and Chief Executive Officer of Progress Energy, since October 2007. Mr. Johnson previously served as President and Chief Operating Officer of Progress Energy from January 2005 to October 2007. In that role, Mr. Johnson oversaw the generation and delivery of electricity by PEC and PEF. Mr. Johnson has been with Progress Energy (formerly CP&L) in a number of roles since 1992, including Group President for Energy Delivery, President and Chief Executive Officer for Progress Energy Service Company, LLC and General Counsel and Secretary for Progress Energy. Before joining Progress Energy, Mr. Johnson was a partner with the Raleigh, N.C. law office of Hunton & Williams LLP, where he specialized in the representation of utilities. Mr. Johnson has served in a variety of senior management positions during his tenure with the Company. His background as a lawyer representing utilities, and his years of hands-on experience at the Company, provide him a unique perspective and a keen understanding of the Company and our industry. Mr. Johnson's breadth of knowledge and experience in addressing key operational, policy, legislative and strategic issues, and his proven leadership skills, will be significant assets to the Company as it implements its long-term strategy in the face of a challenging economy and a changing regulatory and legislative environment. He has served as a director of the Company since 2007.

ROBERT W. JONES, age 59, is the sole owner of Turtle Rock Group, LLC, founded in May 2009. From 1974 until May 2009, Mr. Jones held various management positions at Morgan Stanley, a global provider of financial services to companies, governments and investors. He served as a Senior Advisor from 2006 until May of 2009, and as Managing Director and Vice Chairman from 1997 until 2006. While at Morgan Stanley, Mr. Jones specialized in the utility industry for many years before being named Vice Chairman. Turtle Rock Group, LLC is a financial advisory consulting firm whose sole current client is Morgan Stanley. During his career, Mr. Jones has participated in many major international and domestic utility and project financing transactions, with a particular focus on strategic advisory and capital raising assignments. He has testified before numerous state public utility commissions and has been a frequent speaker on regulatory and corporate governance issues. Mr. Jones's expertise in financial services and his experience in the regulatory arena provide him with a unique perspective that will be beneficial to the Company as it undertakes the expansion projects necessary to implement its balanced solution to meeting its customers' future energy needs in a challenging economy and uncertain regulatory environment. He has served as a director of the Company since 2007. Mr. Jones is Chair of the Board's Finance Committee and a member of the Executive Committee, the Governance Committee and the Organization and Compensation Committee.

W. STEVEN JONES, age 58, is Dean (Emeritus) and Professor of Strategy and Organizational Behavior at the Kenan-Flagler Business School at the University of North Carolina at Chapel Hill, since 2008. He served as Dean of the Kenan-Flagler Business School from August 2003 until August 2008. Prior to joining the Kenan-Flagler Business School in 2003, Mr. Jones had a 30-year career in business. That career included serving as Chief Executive Officer and Managing Director of Suncorp-Metway Ltd., which provides banking, insurance and investing services in Brisbane, Queensland, Australia. He also worked for ANZ, one of Australia's four major banks, in various capacities for eight years. Mr. Jones has international experience in developing strategy, leading change and building organizational capability in a variety of industries. His expertise in the financial services arena will continue to be beneficial as the Company prepares to undertake the expansion projects necessary to satisfy its customers' future energy needs reliably and affordably. Mr. Jones has served as a director of the Company since 2005. He is a member of the Board's Audit and Corporate Performance Committee, the Nuclear Project Oversight Committee and the Operations and Nuclear Oversight Committee.

Other public directorships in past five years:
Premiere Global Services, Inc. (2007 to present)
Bank of America (April 2005 to April 2008)

MELQUIADES R. "MEL" MARTINEZ, age 63, is currently a partner in the law firm of DLA Piper in its Orlando office. Mr. Martinez has had a distinguished career in both the public and private sectors, most recently as a United States Senator from Florida. While serving in the U.S. Senate from 2005 to 2009, he addressed multiple policy and legislative issues as a member of the following Senate committees: Armed Services; Banking, Housing & Urban Affairs; Foreign Relations; Energy and Natural Resources; Commerce; and Special Committee on Aging. Prior to his election, Mr. Martinez served as the Secretary of Housing and Urban Development from 2001 to 2004. His extensive legal, policy and legislative experience will be valuable to the Company as we address new laws and regulations in areas such as environmental compliance, renewable energy standards and energy policy. Prior to representing the State of Florida in the U.S. Senate, Mr. Martinez served as Mayor of Orange County Florida, and as a board member of the Orlando Utilities Commission. He also spent over 25 years in private legal practice, conducting numerous trials in state and federal courts throughout Florida. As a resident and public servant of the State of Florida, Mr. Martinez brings to our Board a unique perspective and first-hand knowledge that will be beneficial as we continue to address key regulatory issues in that State. Mr. Martinez's diversified experience and background will be significant assets to our Company's Board. He has served as a director of the Company since March 1, 2010 and is a member of the Audit and Corporate Performance Committee and the Operations and Nuclear Oversight Committee.

E. MARIE MCKEE, age 59, is Senior Vice President of Corning Incorporated, a manufacturer of components for high-technology systems for consumer electronics, mobile emissions controls, telecommunications and life sciences, since 1996. She also serves as President of the Corning Museum of Glass. Ms. McKee has over 30 years of experience at Corning, where she has held a variety of positions with increasing levels of responsibility. She initially served in various human resources manager positions including Human Resources Director for Corning's Electronics Division, its Research & Development Division and its Centralized Engineering Division. While serving in these positions, Ms. McKee gained significant experience in designing and implementing human resources strategies, business processes and organizational change efforts. She then served in various management positions, including Division Vice President of Corporate Strategic Staffing, Vice President, Human Resources and Senior Vice President, Human Resources and Corporate Diversity Officer. Ms. McKee served as Chairman of Steuben Glass from 1998 until the company was sold in 2008. Ms. McKee has served as a director of the Company and its predecessors since 1999. During her tenure on the Board, Ms. McKee's business experience and perspective have proven valuable to the Company as it has addressed various operational and human resources issues, including executive compensation, succession planning and diversity. Ms. McKee's experience will continue to be beneficial to the Company as shareholders, regulators and legislators continue to focus on executive compensation and corporate governance issues. Ms. McKee is Chair of the Board's Organization and Compensation Committee and a member of the Executive Committee, the Governance Committee, the Nuclear Project Oversight Committee and the Operations and Nuclear Oversight Committee.

JOHN H. MULLIN, III, age 68, is Chairman of Ridgeway Farm, LLC, a limited liability company engaged in farming and timber management, since 1989. He is a former Managing Director of Dillon, Read & Co., a former investment banking firm. Mr. Mullin was employed by Dillon Read for approximately 20 years. During that time, he worked with a diversified mix of clients and was involved in a variety of corporate assignments, including private and public offerings, and corporate restructurings. Since 1989, Mr. Mullin has managed the diversified businesses of Ridgeway Farm. He has served on the boards of a number of other major publicly traded companies, providing him with substantial experience in the areas of corporate strategy, oversight and governance. Mr. Mullin has utilized his broad and extensive business experiences to provide leadership to the Company's Board as Lead Director. He has served as a director of the Company and its predecessors since 1999. Mr. Mullin is Chair of the Board's Governance Committee and a member of the Executive Committee, the Finance Committee and the Organization and Compensation Committee.

Other public directorships in past five years:
Sonoco Products Company (2002 to present)
Hess Corporation (2007 to present)
Liberty Corporation (1989 to 2006)

CHARLES W. PRYOR, JR., age 65, is Chairman of Urenco Investments, Inc., a global provider of services and technology to the nuclear generation industry worldwide, since January 2007. He served as President and Chief Executive Officer of Urenco Investments, Inc. from 2004 to 2006. Mr. Pryor served as President and Chief Executive Officer of the Utilities Business Group of British Nuclear Fuels from 2002 to 2004. From 1997 to 2002, he served as President and Chief Executive Officer of Westinghouse Electric Co., a supplier of nuclear fuel, nuclear services and advanced nuclear plant designs to utilities operating nuclear power plants. Mr. Pryor's service as chief executive officer of a multi-billion dollar company provided him with experience that enables him to understand the financial statements and financial affairs of the Company. Mr. Pryor's knowledge and experience in engineering, power generation, nuclear fuel and the utility industry will help us in the years ahead as our Company pursues a balanced solution to meeting its customers' future energy needs. He has served as a director of the Company since 2007. Mr. Pryor is Chair of the Board's Nuclear Project Oversight Committee and a member of the Audit and Corporate Performance Committee and the Operations and Nuclear Oversight Committee.

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

CARLOS A. SALADRIGAS, age 61, is Chairman and Chief Executive Officer of Regis HRG, which offers a full suite of outsourced human resources services to small and mid-sized businesses. He has served in these positions since July 2008. Mr. Saladrigas served as Chairman, from 2002 to 2007, and Vice Chairman, from 2007 to 2008, of Premier American Bank in Miami, Florida. In 2002, Mr. Saladrigas retired as Chief Executive Officer of ADP Total Source (previously the Vincam Group, Inc.), a Miami-based human resources outsourcing company that provides services to small and mid-sized businesses. Mr. Saladrigas has extensive expertise in both the human resources and financial services arenas. His accounting background provides him with an understanding of the principles used to prepare the Company's financial statements and enables him to effectively analyze those financial statements. Mr. Saladrigas is a resident of Florida and is familiar with the policy issues facing that State. His unique perspective and business acumen continue to be valuable assets to the Board. Mr. Saladrigas has served as a director of the Company since 2001 and is a member of the Board's Audit and Corporate Performance Committee and the Finance Committee.

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

THERESA M. STONE, age 65, has been Executive Vice President and Treasurer of the Massachusetts Institute of Technology Corporation ("M.I.T."), since February 2007. In her role as Executive Vice President and Treasurer, Ms. Stone is responsible for M.I.T.'s capital programs, facilities, human resources and information technology, and serves as M.I.T.'s Chief Financial Officer and Treasurer. Prior to serving in her current role, Ms. Stone served as Executive Vice President and Chief Financial Officer of Jefferson-Pilot Financial (now Lincoln Financial Group) from November 2001 to March 2006. Ms. Stone began her career as an investment banker, advising clients primarily in the financial services industry on financial and strategic matters and has held senior financial executive officer positions at various companies since that time. Ms. Stone's knowledge and expertise in finance make her uniquely qualified to understand and effectively analyze the Company's financial statements, and to assist the Company as it undertakes the expansion efforts necessary to implement its balanced solution to satisfying its customers' energy needs reliably and affordably. She has served as a director of the Company since 2005. Ms. Stone is Chair of the Board's Audit and Corporate Performance Committee and a member of the Executive Committee, the Governance Committee and the Finance Committee.

ALFRED C. TOLLISON, JR., age 67, retired as Chairman and Chief Executive Officer of the Institute of Nuclear Power Operations ("INPO"), a nuclear industry-sponsored nonprofit organization in March 2006. He was employed by INPO from 1987 until March 2006. During his tenure there, Mr. Tollison's responsibilities included industry and government relations, communications, information systems and administrative activities. He also served as the executive director of the National Academy for Nuclear Training. From 1970 until 1987, Mr. Tollison was employed by PEC, where he served in a variety of management positions, including plant general manager of the Brunswick Nuclear Plant and manager of nuclear training. Mr. Tollison's track record and expertise in promoting the safe and reliable operations of our nation's nuclear generating plants will continue to be a significant asset to our board as the Company moves forward with its balanced solution for meeting the future generation needs of its customers safely, reliably and affordably. He has served as a director of the Company since 2006. Mr. Tollison is Vice Chair of the Board's Nuclear Project Oversight Committee and a member of the Audit and Corporate Performance Committee and the Operations and Nuclear Oversight Committee. He also serves as the Nuclear Oversight Director.

PRINCIPAL SHAREHOLDERS

The table below sets forth the only shareholder we know to beneficially own more than 5 percent (5%) of the outstanding shares of our Common Stock as of December 31, 2009. We do not have any other class of voting securities.

Title of Class	Name and Address of Beneficial Owner	Number of Shares Beneficially Owned	Percentage of Class
Common Stock	State Street Corporation One Lincoln Street Boston, MA 02111	25,939,712[1]	9.3

[1] Consists of shares of Common Stock held by State Street Corporation, acting in various fiduciary capacities. State Street Corporation has sole power to vote with respect to 0 shares, sole dispositive power with respect to 0 shares, shared power to vote with respect to 12,892,635 shares and shared power to dispose of 25,939,712 shares. State Street Corporation has disclaimed beneficial ownership of all shares of Common Stock. (Based solely on information contained in a Schedule 13G filed by State Street Corporation on February 12, 2010.)

MANAGEMENT OWNERSHIP OF COMMON STOCK

The following table describes the beneficial ownership of our Common Stock as of February 22, 2010, of (i) all current directors and nominees for director, (ii) each executive officer named in the Summary Compensation Table presented later in this Proxy Statement, and (iii) all directors and nominees for director and executive officers as a group. As of February 22, 2010, none of the individuals or the group in the above categories owned one percent (1%) or more of our voting securities. Unless otherwise noted, all shares of Common Stock set forth in the table are beneficially owned, directly or indirectly, with sole voting and investment power, by such shareholder.

Name	Number of Shares of Common Stock Beneficially Owned[1,2]
John D. Baker II	7,450
James E. Bostic, Jr.	8,445[1]
Harris E. DeLoach, Jr.	5,000
James B. Hyler, Jr.	1,000
William D. Johnson	136,751[2]
Robert W. Jones	1,000
W. Steven Jones	1,000
Jeffrey J. Lyash	19,393[2]
Melquiades R. "Mel" Martinez	—[3]
E. Marie McKee	3,000[1]
Mark F. Mulhern	34,550[2]
John H. Mullin, III	10,000[1]
Charles W. Pryor, Jr.	1,042
Carlos A. Saladrigas	7,000[1]
Paula J. Sims	11,766[2]
Theresa M. Stone	1,000
Alfred C. Tollison, Jr.	1,000
Lloyd M. Yates	27,937[2]
Shares of Common Stock beneficially owned by all directors and executive officers of the Company as a group (25 persons)	438,761[4]

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

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

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

Officer	Restricted Stock	Stock Options
William D. Johnson	16,134	—
Jeffrey J. Lyash	3,834	—
Mark F. Mulhern	5,834	7,000
Paula J. Sims	1,000	—
Lloyd M. Yates	3,834	—

[3] Mr. Martinez was elected to the Board effective March 1, 2010 and did not own any shares of the Company's Common Stock at the time of his election. Mr. Martinez is standing for election to the Board by our shareholders for the first time.

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

Ownership of Units Representing Common Stock

The table below shows ownership of units representing our Common Stock under the Non-Employee Director Deferred Compensation Plan and units under the Non-Employee Director Stock Unit Plan as of February 22, 2010. A unit of Common Stock does not represent an equity interest in the Company, and possesses no voting rights, but is equal in economic value at all times to one share of Common Stock.

Director	Directors' Deferred Compensation Plan	Non-Employee Director Stock Unit Plan
John D. Baker II	1,339	1,489
James E. Bostic, Jr.	11,723	10,017
Harris E. DeLoach, Jr.	10,299	5,989
James B. Hyler, Jr.	1,231	3,090
Robert W. Jones	7,294	4,538
W. Steven Jones	11,911	7,522
Melquiades R. "Mel" Martinez*	67	—
E. Marie McKee	29,288	12,877
John H. Mullin, III	19,601	13,374
Charles W. Pryor, Jr.	2,147	4,538
Carlos A. Saladrigas	6,993	11,013
Theresa M. Stone	10,087	7,522
Alfred C. Tollison, Jr.	9,905	5,989

* Units owned as of March 1, 2010.

The table below shows ownership as of February 22, 2010, of (i) performance units under the Long-Term Compensation Program; (ii) performance units recorded to reflect awards deferred under the Management Incentive Compensation Plan ("MICP"); (iii) performance shares awarded under the Performance Share Sub-Plan of the 1997, 2002 and 2007 Equity Incentive Plans ("PSSP") (see "Outstanding Equity Awards at Fiscal Year-End Table" on page 51); (iv) units recorded to reflect awards deferred under the PSSP; (v) replacement units representing the value of our contributions to the 401(k) Savings & Stock Ownership Plan that would have been made but for the deferral of salary under the Management Deferred Compensation Plan and contribution limitations under Section 415 of the

Internal Revenue Code of 1986, as amended; and (vi) Restricted Stock Units ("RSUs") awarded under the 2002 and 2007 Equity Incentive Plans.

Officer	Long-Term Compensation Program	MICP	PSSP	PSSP Deferred	MDCP	RSUs
William D. Johnson	—	1,711	146,294	—	1,059	66,001
Jeffrey J. Lyash	—	—	36,289	—	314	25,398
Mark F. Mulhern	—	3,853	28,308	2,452	—	20,942
Paula J. Sims	—	7,347	26,621	1,512	—	19,617
Lloyd M. Yates	—	2,672	36,132	6,376	158	25,325

TRANSACTIONS WITH RELATED PERSONS

There were no transactions in 2009, and there are no currently proposed transactions involving more than $120,000, in which the Company or any of its subsidiaries was or is to be a participant and in which any of the Company's directors, executive officers, nominees for director or any of their immediate family members had a direct or indirect material interest.

Our Board of Directors has adopted policies and procedures for the review, approval or ratification of Related Person Transactions under Item 404(a) of Regulation S-K (the "Policy"), which is attached to this Proxy Statement as Exhibit A. The Board has determined that the Governance Committee is best suited to review and approve Related Person Transactions because the Governance Committee oversees the Board of Directors' assessment of our directors' independence. The Governance Committee will review and may recommend to the Board amendments to this Policy from time to time.

For the purposes of the Policy, a "Related Person Transaction" is a transaction, arrangement or relationship, including any indebtedness or guarantee of indebtedness (or any series of similar transactions, arrangements or relationships), in which we (including any of our subsidiaries) were, are or will be a participant and the amount involved exceeds $120,000, and in which any Related Person had, has or will have a direct or indirect material interest. The term "Related Person" is defined under the Policy to include our directors, executive officers, nominees to become directors and any of their immediate family members.

Our general policy is to avoid Related Person Transactions. Nevertheless, we recognize that there are situations where Related Person Transactions might be in, or might not be inconsistent with, our best interests and those of our shareholders. These situations could include (but are not limited to) situations where we might obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when we provide products or services to Related Persons on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. In determining whether to approve or disapprove each Related Person Transaction, the Governance Committee considers various factors, including (i) the identity of the Related Person; (ii) the nature of the Related Person's interest in the particular transaction; (iii) the approximate dollar amount involved in the transaction; (iv) the approximate dollar value of the Related Person's interest in the transaction; (v) whether the Related Person's interest in the transaction conflicts with his obligations to the Company and its shareholders; (vi) whether the transaction will provide the Related Person with an unfair advantage in his dealings with the Company; and (vii) whether the transaction will affect the Related Person's ability to act in the best interests of the Company and its shareholders. The Governance Committee will only approve those Related Person Transactions that are in, or are not inconsistent with, the best interests of the Company and its shareholders.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934 requires our directors and executive officers to file reports of their holdings and transactions in our securities with the SEC and the NYSE. Based on our records and other information, we believe that all Section 16(a) filing requirements applicable to our directors and executive officers with respect to the Company's 2009 fiscal year were met, except as follows: James Scarola inadvertently failed to timely file a Form 4 related to the deferral, in 2009 and 2010, of portions of two awards granted under the Company's Management Incentive Compensation Plan. A Form 4 reporting both transactions was filed on March 16, 2010. Paula J. Sims inadvertently failed to file on a timely basis a Form 4 with respect to the deferral in 2009 of a portion of an award granted under the Company's Management Incentive Compensation Plan. A Form 4 reporting the transaction was filed on March 16, 2010. Additionally, with regard to the Company's 2010 fiscal year, each of Jeffrey A. Corbett, Vincent M. Dolan, William D. Johnson, Michael A. Lewis, Jeffrey J. Lyash, John R. McArthur, Mark F. Mulhern, James Scarola, Frank A. Schiller, Paula J. Sims, Jeffrey M. Stone and Lloyd M. Yates inadvertently failed to file on a timely basis a Form 4 with respect to the payout of performance units granted under the Company's Performance Share Sub-Plan. A Form 4 reporting the transaction was filed by each individual on March 11, 2010.

CORPORATE GOVERNANCE GUIDELINES AND CODE OF ETHICS

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

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

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

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

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

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

DIRECTOR INDEPENDENCE

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

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

Additionally, the Board of Directors has determined that David L. Burner, who served as a member of the Board during a portion of 2009, was independent as that term is defined under the general independence standards contained in the NYSE's listing standards. In addition to considering the NYSE's general independence standards, the Board has adopted categorical standards to assist it in making determinations of independence. The Board's categorical independence standards are outlined in our Governance Guidelines. The Governance Guidelines are available on our Internet Web site and can be accessed at *www.progress-energy.com/investor*. All directors, former directors and director nominees identified as independent in this Proxy Statement meet these categorical standards.

In determining that the individuals named above are or were independent directors, the Governance Committee considered their involvement in various ordinary course commercial transactions and relationships. During 2009, Ms. McKee and Messrs. DeLoach and Mullin served as officers and/or directors of companies that have been among the purchasers of the largest amounts of electric energy sold by PEC during the last three preceding calendar years. Messrs. Baker, Mullin and Saladrigas served as officers and/or directors of companies that purchase electric energy from PEF. Mr. Robert W. Jones was an employee of Morgan Stanley through May 2009. Morgan Stanley has provided a variety of investment banking services to us during the past several years; however, Mr. Jones had no direct or indirect material interests or involvement in transactions between the Company and Morgan Stanley. Mr. Jones is no longer a Morgan Stanley employee although his firm provides services to Morgan Stanley. Mr. W. Steven Jones serves as a director of a communications technology company that provided services to us in 2009. Mr. Baker currently serves as a director of Wells Fargo & Company and is a former director of Wachovia Corporation. Both of these entities have been part of our core bank group and have provided a variety of banking and investment services to us during the past several years. Mr. Pryor is a director of a company that has affiliates that provide uranium enrichment services to PEC and PEF. Mr. Tollison is a former employee of PEC and thus receives a modest pension from us. All of the described transactions were ordinary course commercial transactions conducted at arm's length and in compliance with the NYSE's standards for director independence. In addition, the Governance Committee considers the relationships our directors have with tax-exempt organizations that receive contributions from the Company. The Governance Committee considered each of these transactions and relationships and determined that none of them was material or affected the independence of the directors involved under either the general independence standards contained in the NYSE's listing standards or our categorical independence standards.

BOARD, BOARD COMMITTEE AND ANNUAL MEETING ATTENDANCE

The Board of Directors is currently comprised of fourteen (14) members. The Board of Directors met six times in 2009. Average attendance of the directors at the meetings of the Board and its committees held during 2009 was 90 percent, and no director attended less than 80 percent of all Board and his/her respective committee meetings held in 2009.

Our Company expects all directors to attend its annual meetings of shareholders. Such attendance is monitored by the Governance Committee. All directors who were serving as directors as of May 13, 2009, the date of the 2009 Annual Meeting of Shareholders, attended that meeting, with the exception of Mr. Burner, who retired from the Board effective May 13, 2009, and Mr. Saladrigas, who was recovering from an illness at the time of the meeting.

BOARD COMMITTEES

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

Executive Committee

The Executive Committee is presently composed of one director who is an officer and five nonmanagement directors: Messrs. William D. Johnson—Chair, Harris E. DeLoach, Jr., Robert W. Jones, and John H. Mullin, III, and Ms. E. Marie McKee and Ms. Theresa M. Stone. The authority and responsibilities of the Executive Committee are described in our By-Laws. Generally, the Executive Committee will review routine matters that arise between meetings of the full Board and require action by the Board. The Executive Committee held no meetings in 2009.

Audit and Corporate Performance Committee

The Audit and Corporate Performance Committee (the "Audit Committee") is presently composed of the following seven nonmanagement directors: Ms. Theresa M. Stone—Chair, and Messrs. James E. Bostic, Jr., W. Steven Jones, Melquiades R. "Mel" Martinez, Charles W. Pryor, Jr., Carlos A. Saladrigas, and Alfred C. Tollison, Jr. All members of the committee are independent as that term is defined under the enhanced independence standards for audit committee members contained in the Securities Exchange Act of 1934 and the related rules, as amended, as incorporated into the listing standards of the NYSE. Mr. Saladrigas and Ms. Stone have been designated by the Board as the "Audit Committee Financial Experts," as that term is defined in the SEC's rules. The work of the Audit Committee includes oversight responsibilities relating to the integrity of our financial statements, compliance with legal and regulatory requirements, the qualifications and independence of our independent registered public accounting firm, performance of the internal audit function and of the independent registered public accounting firm, and the Corporate Ethics Program. The role of the Audit Committee is further discussed under "Report of the Audit and Corporate Performance Committee" below. The Audit Committee held seven meetings in 2009.

Corporate Governance Committee

The Governance Committee is presently composed of the following five nonmanagement directors: Messrs. John H. Mullin, III—Chair/Lead Director, Harris E. DeLoach, and Robert W. Jones, and Ms. E. Marie McKee and Ms. Theresa M. Stone. All members of the Governance Committee are independent as that term is defined under the general independence standards contained in the NYSE listing standards. The Governance Committee is responsible for making recommendations to the Board with respect to the governance of the Company and the Board. Its responsibilities include recommending amendments to our Charter and By-Laws, making recommendations regarding the structure, charter, practices and policies of the Board, ensuring that processes are in place for annual Chief Executive Officer performance appraisal and review of succession planning and management development, recommending a process for the annual assessment of Board performance, recommending criteria for Board membership, reviewing the qualifications of and recommending to the Board nominees for election. The Governance Committee is responsible for conducting investigations into or studies of matters within the scope of its responsibilities and to retain outside advisors to identify director candidates. The Governance Committee will consider qualified candidates for director nominated by shareholders at an annual meeting of shareholders, provided, however, that written notice of any shareholder nominations must be received by the Corporate Secretary of the Company no later than the close of business on the 120th calendar day before the date our Proxy Statement was released to shareholders in connection with the previous year's annual meeting. See "Future Shareholder Proposals" below for more information regarding shareholder nominations of directors. The Governance Committee held three meetings in 2009.

Finance Committee

The Finance Committee is presently composed of the following six nonmanagement directors: Messrs. Robert W. Jones—Chair, John D. Baker II, James B. Hyler, Jr., John H. Mullin, III, and Carlos A. Saladrigas, and Ms. Theresa M. Stone. The Finance Committee reviews and oversees our financial policies and planning, financial position, strategic planning and investments, pension funds and financing plans. The Finance Committee also monitors our risk management activities and financial position and recommends changes to our dividend policy and proposed budget. The Finance Committee held four meetings in 2009.

Nuclear Project Oversight Committee (*ad hoc*)

The Nuclear Project Oversight Committee is presently composed of the following six nonmanagement directors: Messrs. Charles W. Pryor, Jr.—Chair, Alfred C. Tollison, Jr.—Vice Chair, James E. Bostic, Jr., Harris E. DeLoach, Jr., and W. Steven Jones, and Ms. E. Marie McKee. The Nuclear Project Oversight Committee is an *ad hoc* committee that serves as the primary point of contact for Board oversight of the construction of new nuclear projects, and advises the Board of construction status, including schedule, cost and legal, legislative and regulatory activities. The Nuclear Project Oversight Committee held no meetings in 2009.

Operations and Nuclear Oversight Committee

The Operations and Nuclear Oversight Committee is presently composed of the following seven nonmanagement directors: Messrs. Harris E. DeLoach, Jr.—Chair, James E. Bostic, Jr., W. Steven Jones, Melquiades R. "Mel" Martinez, Charles W. Pryor, Jr., and Alfred C. Tollison, Jr., and Ms. E. Marie McKee. The Operations and Nuclear Oversight Committee reviews our load forecasts and plans for generation, transmission and distribution, fuel procurement and transportation, customer service, energy trading and term marketing, and other Company operations. The Operations and Nuclear Oversight Committee reviews and assesses our policies, procedures, and practices relative to the protection of the environment and the health and safety of our employees, customers, contractors and the public. The Operations and Nuclear Oversight Committee advises the Board and makes recommendations for the Board's consideration regarding operational, environmental and safety-related issues. The Operations and Nuclear Oversight Committee held four meetings in 2009.

Organization and Compensation Committee

The Organization and Compensation Committee (the "Compensation Committee") is presently composed of the following six nonmanagement directors: Ms. E. Marie McKee—Chair, and Messrs. John D. Baker II, Harris E. DeLoach, Jr., James B. Hyler, Jr., Robert W. Jones, and John H. Mullin, III. All members of the Compensation Committee are independent as that term is defined under the general independence standards contained in the NYSE listing standards. The Compensation Committee verifies that personnel policies and procedures are in keeping with all governmental rules and regulations and are designed to attract and retain competent, talented employees and develop the potential of these employees. The Compensation Committee reviews all executive development plans, makes executive compensation decisions, evaluates the performance of the Chief Executive Officer and oversees plans for management succession.

The Compensation Committee may hire outside consultants, and the Compensation Committee has no limitations on its ability to select and retain consultants as it deems necessary or appropriate. Annually, the Compensation Committee evaluates the performance of its compensation consultant to assess its effectiveness in assisting the Committee with implementing the Company's compensation program and principles. For 2009, the Compensation Committee retained Hewitt Associates as its executive compensation and benefits consultant to assist the Compensation Committee in meeting its compensation objectives for our Company. Under the terms of its engagement, in 2009, Hewitt Associates reported directly to the Compensation Committee. In January 2010, Hewitt Associates spun off its executive compensation practice into a separate entity named Meridian Compensation Partners, LLC ("Meridian"), an independent agency wholly-owned by its partners. Meridian reports directly to the Compensation Committee.

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

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

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

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

The Compensation Committee held seven meetings in 2009.

Compensation Committee Interlocks and Insider Participation

None of the directors who served as members of the Compensation Committee during 2009 was our employee or former employee and none of them had any relationship requiring disclosure under Item 404 of Regulation S-K. During 2009, none of our executive officers served on the compensation committee (or equivalent), or the board of directors of another entity whose executive officer(s) served on our Compensation Committee or Board of Directors.

DIRECTOR NOMINATING PROCESS AND COMMUNICATIONS WITH BOARD OF DIRECTORS

Governance Committee

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

Director Candidate Recommendations and Nominations by Shareholders

Shareholders should submit any director candidate recommendations in writing in accordance with the method described under "Communications with the Board of Directors" below. Any director candidate recommendation that is submitted by one of our shareholders to the Governance Committee will be acknowledged, in writing, by the Corporate Secretary. The recommendation will be promptly forwarded to the Chair of the Governance Committee, who will place consideration of the recommendation on the agenda for the Governance Committee's regular December meeting. The Governance Committee will discuss candidates recommended by shareholders at its December meeting and present information regarding such candidates, along with the Governance Committee's recommendation regarding each candidate, to the full Board for consideration. The full Board will determine whether it will nominate a particular candidate for election to the Board.

Additionally, in accordance with Section 11 of our By-Laws, any shareholder of record entitled to vote for the election of directors at the applicable meeting of shareholders may nominate persons for election to the Board of Directors if that shareholder complies with the notice procedure set forth in the By-Laws and summarized in "Future Shareholder Proposals" below.

Governance Committee Process for Identifying and Evaluating Director Candidates

The Governance Committee evaluates all director candidates, including those nominated or recommended by shareholders, in accordance with the Board's qualification standards, which are described in the Governance Guidelines. The Committee evaluates each candidate's qualifications and assesses them against the perceived needs of the Board. Qualification standards for all Board members include: integrity; sound judgment; independence as defined under the general independence standards contained in the NYSE listing standards and the categorical standards adopted by the Board; financial acumen; strategic thinking; ability to work effectively as a team member; demonstrated leadership and excellence in a chosen field of endeavor; experience in a field of business; professional or other activities that bear a relationship to our mission and operations; appreciation of the business and social environment in which we operate; an understanding of our responsibilities to shareholders, employees, customers and the communities we serve; and service on other boards of directors that would not detract from service on our Board.

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

Communications with the Board of Directors

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

We screen mail addressed to the Board, the Governance Committee or any specified individual director for security purposes and to ensure that the mail relates to discrete business matters relevant to the Company. Mail that satisfies these screening criteria is forwarded to the appropriate director.

BOARD LEADERSHIP STRUCTURE AND ROLE IN RISK OVERSIGHT

Board Leadership

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

Currently, the Board believes that the Company's interests are best served by having the Chief Executive Officer also serve as Chairman because it allows the Board to most effectively and directly leverage the Chief Executive Officer's day-to-day familiarity with the Company's operations. This is particularly beneficial for the Board at this time given the rapidly evolving nature of the energy industry and the complexity of the projects being considered by the Company, including the construction of new nuclear facilities.

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

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

Board Role in Risk Oversight

We have established a risk management framework that is the backbone for risk management activities that occur across Progress Energy. The framework establishes processes for identifying, measuring, managing and monitoring risk across the Company and its subsidiaries. We also maintain an ongoing inventory that details risk types, the internal department that manages each type of risk and the Board committees that are involved in overseeing those activities. Our Chief Executive Officer and Senior Management have responsibility for assessing and managing the Company's exposure to risk. In this regard, we have established a Risk Management Committee, comprised of various senior executives, that provides guidance and direction in the identification and management of financial risks. The Board is not involved in the Company's day-to-day risk management activities; however, the various Board Committees are involved in different aspects of overseeing those activities.

The Audit and Corporate Performance Committee is responsible for ensuring that appropriate guidelines and controls are in place and reviews the framework for managing risk and adherence to that framework. The Audit and Corporate Performance Committee reviews and discusses with management the Company's guidelines and polices governing risk assessment and risk management.

The Finance Committee is responsible for the oversight of the Risk Management Committee Policy and Guidelines. It oversees the financial risks associated with guarantees, risk capital, corporate financing activities and debt structure. The Finance Committee ensures that dollar amounts and limits are managed within the established framework. The Finance Committee reports to the full Board at least once a quarter.

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

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

The enterprise risk management program is reviewed with the Board on an annual basis. Our risk management framework is designed to enable the Board to stay informed about and understand the key risks facing the Company, understand how those risks relate to the Company's business and strategy, and the steps the Company is taking to manage those risks.

COMPENSATION DISCUSSION AND ANALYSIS

This Compensation Discussion and Analysis ("CD&A") has four parts. The first part describes the Company's executive compensation philosophy and provides an overview of the compensation program and process. The second part describes each element of the Company's executive compensation program. The third part describes how the Organization and Compensation Committee of the Company's Board of Directors (in this CD&A, the "Committee") applied each element to determine the compensation paid to each of the named executive officers in the Summary Compensation Table on page 45 (the "named executive officers") for the services they provided to the Company in 2009. For 2009, the Company's named executive officers were:

- William D. Johnson, Chairman, President and Chief Executive Officer;
- Mark F. Mulhern, Senior Vice President and Chief Financial Officer;
- Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, Progress Energy Florida, Inc. (PEF));
- Lloyd M. Yates, President and Chief Executive Officer, Progress Energy Carolinas, Inc. (PEC); and
- Paula J. Sims, Senior Vice President – Power Operations.

The fourth part consists of the Committee's Report.

Following the CD&A are the tables setting forth the 2009 compensation for each of the named executive officers, as well as a discussion concerning compensation for the members of the Company's Board of Directors. Throughout this CD&A, the Company is at times referred to as "we," "our" or "us."

I. COMPENSATION PHILOSOPHY AND OVERVIEW

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

- **Aligning the interests of shareholders and management.** We believe that our major shareholders invest in the Company because they believe we can produce average annual total shareholder return in the 7% to 10% range over the long term. Total shareholder return is defined as the stock price appreciation plus dividends over the period, divided by the share price at the beginning of the measurement period. Further, our investors do not expect or desire significant volatility in our stock price. Accordingly, our executive compensation program is designed to encourage management to lead our Company in a way that consistently produces earnings per share growth and a competitive dividend yield. In the two years since Mr. Johnson became our Chief Executive Officer, under his leadership and that of the Committee, many actions have been taken to align the executive compensation structure with our shareholders' interests. These actions include a significant reduction of perquisites for both our executive officers and non-executive officers who are in senior management; an increase in the stock ownership guidelines; implementation of a new performance measure in the Management Incentive Compensation Plan ("MICP") to further enhance transparency and alignment of performance and payouts for executive officers and non-executive officers in senior management; and a modification of our Performance Share Sub-Plan ("PSSP") to closely align awards under that plan to our operating results, actual total shareholder returns, and, with respect to our peers, relative total shareholder returns.

- **Rewarding operating performance results that are consistent with reliable and efficient electric service.** We believe that to achieve this goal over the long term, we must:
    - deliver high levels of customer satisfaction;
    - operate our systems reliably and efficiently;
    - maintain a constructive regulatory environment;
    - have a productive, engaged and highly motivated workforce;
    - meet or exceed our operating plans and budgets;
    - be a good corporate citizen; and
    - produce value for our investors.

Therefore, we determine base salary levels and annual incentive compensation based on corporate performance in these areas, along with individual contribution and performance.

- **Attracting and retaining an experienced and effective management team.** The competition for skilled and experienced management is significant in the utility industry. We believe that the management of our business requires executives with a variety of experiences and skills. We expect the competition for talent to continue to intensify, particularly in the nuclear, renewable energy sources, and emerging technologies areas, as the industry enters a significant capital expenditure phase and the requirement for reliable and environmentally responsible generating capacity increases. To address this issue, we have designed market-based compensation programs that are competitive and are aligned with our corporate strategy.

Consistent with these principles, the Committee seeks to provide executive officers a compensation program that is competitive in the market place and provides incentives necessary to motivate executives to perform in the best interests of the Company and its shareholders.

In determining an individual executive officer's compensation opportunity, the Committee believes that it must be competitive within the marketplace for each particular executive officer. As such, the compensation opportunities vary significantly from individual to individual based on the specific nature of the executive position. For example, our Chief Executive Officer is responsible for the overall performance of the Company and, as such, his position has a greater scope of responsibility than our other executive positions and is benchmarked accordingly. From a market perspective, the position of chief executive officer receives a greater compensation opportunity than other executive positions. The Committee therefore sets our Chief Executive Officer's compensation opportunity at levels that reflect the responsibilities of his position and the Committee's expectations.

ASSESSMENT OF RISK

Our Company is highly regulated at both the federal and state levels, and therefore significant swings in earnings performance or growth over time are less influenced by any particular individual or groups of individuals. We believe the variable components of our compensation program for executive officers do not incentivize excessive risk taking for the following reasons:

- Our incentive compensation practices do not reward the executive officers for meeting or exceeding volume or revenue targets.

- Our compensation program is evaluated annually for its effectiveness and consistency with the Company's goals without promoting excessive risk.

- Our compensation program appropriately balances short- and long-term incentives with approximately 60% of total target compensation for the executive officers provided in equity and focused on long-term performance.

- The PSSP rewards significant and sustainable performance over the longer term by focusing on three-year earnings per share growth and relative total shareholder return targets.

- The MICP in effect for 2009 specifically focuses on earnings before interest, taxes, depreciation and amortization ("EBITDA"), and the MICP that is in effect for 2010 specifically focuses on legal entity net income, because we believe that these are appropriate measures to assess the intrinsic value of the Company to determine whether the Company has been successful in its fundamental business.

- Our compensation programs are designed to make it difficult for any one person to meaningfully influence his or her own incentive award.

- The executive officers receive restricted stock units that generally have a three-year vesting period so that their upside potential and downside risk are aligned with that of our shareholders and promote long-term performance over the vesting period.

- The executive officers are subject to stock ownership guidelines independently set by the Board to reflect the compensation program's goals of risk assumption and sharing between executives and shareholders.

We have determined that the compensation program for non-executive officers who are in senior management positions does not encourage excessive risk taking for all the reasons stated above.

COMPENSATION PROGRAM STRUCTURE

The table below summarizes the current elements of our executive compensation program.

Element	Brief Description	Primary Purpose	Short- or Long-Term Focus
Base Salary	Fixed compensation. Annual merit increases reward individual performance and growth in the position.	Basic element of compensation and necessary to attract and retain.	Short-term (annual)
Annual Incentive	Variable compensation based on achievement of annual performance goals.	Rewards operating performance results that are consistent with reliable and efficient electric service.	Short-term (annual)
Long-Term Incentives — Performance Shares	Variable compensation based on achievement of long-term performance goals.	Align interests of shareholders and management and aid in attracting and retaining executives.	Long-term
Long-Term Incentives — Restricted Stock/Restricted Stock Units	Fixed compensation based on target levels. Service-based vesting.	Align interests of shareholders and management and essential in attracting and retaining executives.	Long-term
Supplemental Senior Executive Retirement Plan	Formula-based compensation, based on salary, annual incentives and eligible years of service.	Provides long-term retirement benefit influenced by service and performance. Aids in attracting and retaining executives.	Long-term
Management Change-In-Control Plan	Elements based on specific plan eligibility.	Aligns interests of shareholders and management and aids in (i) attracting executives; (ii) retaining executives during transition following a change-in-control; and (iii) focusing executives on maximizing value for shareholders.	Long-term
Employment Agreements	Define Company's relationship with its executives and provide protection to each of the parties in the event of termination of employment.	Aid in attracting and retaining executives.	Long-term
Executive Perquisites	Personal benefits awarded outside of base pay and incentives.	Aid in attracting and retaining executives.	Short-term (annual)
Other Broad-Based Benefits	Employee benefits such as health and welfare benefits, 401(k) and pension plan.	Basic elements of compensation expected in the marketplace. Aid in attracting and retaining executives.	Both Short- and Long-term
Deferred Compensation	Provides executives with tax deferral options in addition to those available under our qualified plans.	Aids in attracting and retaining executives.	Long-term

The Committee believes these various compensation program elements:

- link compensation with our short- and long-term success by using operating and financial performance measures in determining payouts for annual and long-term incentive plans;
- align management interests with investor expectations by rewarding executives for delivering long-term total shareholder return;
- attract and retain executives by maintaining compensation that is competitive with our peer group;
- foster effective teamwork and collaboration between executives working in different areas to support our core values, strategy and interests;
- comply in all material respects with applicable laws and regulations; and
- can be readily understood by us, the Committee, our executives and our shareholders, and therefore are effective in meeting our business objectives.

PROGRAM ADMINISTRATION

Our executive compensation program is administered by the Committee, which is composed of six independent directors (as defined under the NYSE Corporate Governance Rules). Members of the Committee currently do not receive compensation under any compensation program in which our executive officers participate. For a discussion of director compensation, see the "Director Compensation" section on page 69 of this Proxy Statement.

The Committee's charter authorizes the Committee to hire outside consultants, and the Committee has no limitations on its ability to select and retain consultants as it deems necessary or appropriate. The Committee evaluates the performance of its compensation consultant annually to assess the consultant's effectiveness in assisting the Committee with implementing the Company's compensation program and principles. The Committee retained Hewitt Associates ("Hewitt") as its independent executive compensation consultant to assist the Committee in meeting its compensation objectives for our Company. Under the terms of its engagement, in 2009 Hewitt reported directly to the Committee. In January 2010, Hewitt spun off its executive compensation practice into a separate entity named Meridian Compensation Partners, LLC ("Meridian"), an independent agency wholly-owned by its partners. Meridian reports directly to the Committee.

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

- advising the Committee on general trends in executive compensation and benefits;
- summarizing developments relating to disclosure, risk assessment process and other technical areas;
- performing benchmarking and competitive assessments;
- assistance in designing incentive plans;
- performing financial analysis related to plan design and assisting the Committee in making pay decisions in light of results; and
- recommending appropriate performance metrics.

Hewitt did not provide any services or products to the Company other than those provided to the Committee and related to the Company's executive compensation and benefits program. Meridian solely provides executive compensation advisory services to the Committee and provides no other services to the Committee or the Company.

Our executive officers meet with the compensation consultant to ensure the consultant understands the Company's business strategy. In addition, the executive officers ensure that the Committee receives administrative support and assistance, and make recommendations to the Committee to ensure that compensation plans are aligned with our business strategy and meet the principles described above. John R. McArthur, our Executive Vice President, serves as management's liaison to the Committee. Our executive officers and other Company employees provide the consultant with information regarding our executive compensation plans and benefits and how we administer them on an as-needed basis. William D. Johnson, our Chief Executive Officer, is responsible for conducting annual performance evaluations of the other executive officers and making recommendations to the Committee regarding those executives' compensation. The Committee conducts an annual performance evaluation of Mr. Johnson.

COMPETITIVE POSITIONING PHILOSOPHY

The Committee's compensation philosophy is to establish target compensation opportunities near the 50th percentile of the market, with flexibility to pay higher or lower amounts based on individual and corporate performance. The Committee believes that this philosophy is aligned with our executive compensation objective of linking pay to actual performance.

When we set and benchmark compensation for our executives against a peer group, we focus on "target" compensation. Target compensation is the value of a pay opportunity as of the beginning of the year. For short-term incentives, this means the value of that incentive opportunity based on the target percentage of salary if our performance objectives are achieved. For example, the Chief Executive Officer's target incentive opportunity is 85% of salary. This means if we reach our target financial objectives for the year, a target incentive award would likely be paid. Correspondingly, if performance should fall short or rise above these goals then the earned incentive award would typically be lesser or greater than target. In any event, target incentive opportunities are not a certainty but are a function of business results. For the performance shares, the ultimate value of any earned award is entirely a function of performance against the pre-established 3-year performance goals as well as the value of the underlying stock price. Also, for the restricted shares the value of any earned award is a function of extended service and the value of the underlying stock price. The target value is not a certainty but only the value of the opportunity.

What ultimately might be earned from either short- or long-term incentives is a function of performance and extended service. We do not benchmark realized values from our programs. With respect to our variable pay programs it is generally not the Company's purpose to deliver comparable pay outcomes since outcomes can differ by company based on their performance. Our general compensation objective is to deliver comparable pay opportunities. Realized results will then be a significant function of performance and extended service. This is a common convention among companies; nonetheless, it is an important context to consider when reviewing the remainder of this CD&A where regular references to targets and/or grant date values for our compensation programs appear.

Progress Energy, a regulated electric utility holding company, is considered to be part of the broader industry classification of electric utilities. The Company is included in several well-publicized indices, including the S&P Electric Index and the Philadelphia Utility Index. 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 the aspect of the value chain in which the company participates (generation, transmission and/or delivery), and how much of its business is 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 performance and market valuation characteristics such as earnings multiples, earnings growth prospects and dividend yields.

Progress Energy generally is identified as being in the regulated integrated subsector. This means Progress Energy and its peer companies are primarily rate-of-return regulated, operate in the full range of the value chain, and typically have requirements to serve all customers under state utility regulations. Other companies that are similar to us from a business model perspective and that are generally categorized in our subsector include companies like Southern Company, Duke Energy, SCANA, Xcel and PG&E. The Committee, therefore, monitors companies like these in comparing and evaluating Progress Energy's financial performance for investors and compensation for executives.

On an annual basis, the Committee's compensation consultant provides the Committee with a written analysis comparing base salaries, target annual incentives and the grant date value of long-term incentives of our executive officers to compensation opportunities provided to executive officers of our peers. For 2009, the Committee approved the use of the same peer group of 18 integrated utilities used in the prior year (that is, utilities that have transmission, distribution and generation assets) (the "Benchmarking Peer Group"). The Benchmarking Peer Group was chosen based primarily on revenues. These companies would likely be companies with which we primarily compete for executive talent. The table below lists the companies in the Benchmarking Peer Group.

Allegheny Energy, Inc.	Edison International	Pinnacle West Capital Corporation
Ameren Corporation	Entergy Corporation	PPL Corporation
American Electric Power Co., Inc.	Exelon Corporation	SCANA Corporation
Dominion Resources, Inc.	FirstEnergy Corporation	Southern Company
DTE Energy Company	FPL Group, Inc.	TECO Energy, Inc.
Duke Energy Corporation	PG&E Corporation	Xcel Energy, Inc.

The Committee will annually evaluate the Benchmarking Peer Group to ensure that it remains appropriate for compensation comparisons.

SECTION 162(m) IMPACTS

Section 162(m) of the Internal Revenue Code of 1986, as amended, limits, with certain exceptions, the amount a publicly held company may deduct each year for compensation over $1 million paid or accrued with respect to its chief executive officer and any of the other three most highly compensated officers (excluding the chief financial officer). Certain performance-based compensation is, however, specifically exempt from the deduction limit. To qualify as performance-based, compensation must be paid pursuant to a plan that is:

- administered by a committee of outside directors;
- based on achieving objective performance goals; and
- disclosed to and approved by the shareholders.

The Committee considers the impact of Section 162(m) when designing executive compensation elements and attempts to minimize nondeductible compensation. The Company received shareholder approval of the Progress Energy 2009 Executive Incentive Plan (the "EIP"), an annual cash incentive plan for the Company's named executive officers, at its 2009 Annual Meeting of Shareholders. The MICP and EIP were designed to work together to enable the Company to preserve the tax deductibility of incentive awards under Section 162(m) of the Internal Revenue Code, as amended, to the extent practicable. The sole purpose of the EIP is to preserve the tax deductibility of incentive awards that are qualified performance-based compensation.

STOCK OWNERSHIP GUIDELINES

To align the interests of our executives with the interests of shareholders, the Board of Directors utilizes stock ownership guidelines for all executive officers. The guidelines are designed to ensure that our management maintains a significant ownership stake in the Company. The guidelines require each senior executive to own a multiple of his or her base salary in the form of Company common stock generally within five years of assuming his or her position. The required levels of ownership are designed to reflect the level of responsibility that the executive positions entail.

Each year, the Committee benchmarks both the position levels and the multiples in our guidelines against those of the Benchmarking Peer Group and general industry designs. The benchmarking for 2009 indicated that the Company's guidelines were "at market" with respect to ownership levels, the types of equity that count toward ownership, and the timeframe for compliance. The stock ownership guidelines for our executive officer positions are shown in the table below:

Position Level	Stock Ownership Guidelines
Chief Executive Officer	5.0 times Base Salary
Chief Operating Officer	4.0 times Base Salary
Chief Financial Officer	3.0 times Base Salary
Presidents/Executive Vice Presidents/Senior Vice Presidents	3.0 times Base Salary

For purposes of meeting the applicable guidelines, the following are considered as common stock owned by an executive: (i) shares owned outright by the executive; (ii) stock held in any defined contribution, Employee Stock Ownership Plan or other stock-based plan; (iii) phantom stock deferred under an annual incentive or base salary deferral plan; (iv) stock earned and deferred in any long-term incentive plan account; (v) restricted stock awards and restricted stock units; and (vi) stock held in a family trust or immediate family holdings.

As of February 23, 2010, our named executive officers were in compliance with the guidelines (see Management Ownership table on page 10 of this Proxy Statement for specific details). As an indication of Mr. Johnson's alignment of his interests with that of our shareholders, he currently holds equity more than 8½-times his base salary which exceeds the 5-times base salary required under the guidelines. Further, he has not sold any of the shares he received upon the vesting of his restricted stock awards, restricted stock units, and performance shares since he became Chief Executive Officer.

II. ELEMENTS OF COMPENSATION

The various elements of our executive compensation program described above under the caption "Compensation Program Structure" on page 24 are designed to meet the three key principles described under the caption "Compensation Philosophy and Overview" on page 21 of this Proxy Statement. We have designed an allocation of long-term to short-term compensation that reflects the job responsibilities of the executive, provides an incentive for the executive to maximize his or her contribution to the Company, and is consistent with market practices. In general, we believe that the more senior an executive's position, the greater responsibility and influence he or she has regarding the long-term strategic direction of the Company. Thus, the Chief Executive Officer's target long-term compensation is designed to account for approximately two-thirds of his total compensation package (i.e., base salary, target annual incentives, and long-term incentives). By comparison, Senior Vice Presidents' target long-term compensation is designed to constitute approximately one-half of their total target compensation packages. Under this approach, executives who bear the most responsibility for and influence over the Company's long-term performance receive compensation packages that provide greater incentives to achieve the Company's long-term objectives.

The table below shows the mix of short-term and long-term incentive awards to each named executive officer for 2009. Percentages for incentives are expressed as a percentage of base salary. Additional elements of compensation are discussed further in this section.

Named Executive Officer	Base Salary (as of 1/1/10)	Short-Term (annual) Incentive Target[1]	Long-Term Incentive Targets as a Percentage of Salary		Total Incentive Target
			Performance Shares[2]	Restricted Stock	
William D. Johnson	$990,000	85%	233%	117%	435%
Mark F. Mulhern	$425,000	55%	117%	58%	230%
Jeffrey J. Lyash	$453,000	55%	117%	58%	230%
Lloyd M. Yates	$448,000	55%	117%	58%	230%
Paula J. Sims	$370,000	45%	100%	50%	195%

[1] Annual incentive awards can range from 0%-200% of target percentages noted above.

[2] Payout opportunities can range from 0%-200% of grant.

To assess overall compensation, the Committee utilizes tally sheets that provide a summary of the elements of compensation for each senior executive. The tally sheets indicate target and actual pay earned. They also summarize potential retirement benefits at age 65, current equity holdings, and potential value from severance.

1. BASE SALARY

The primary purpose of base salaries is to provide a basic element of compensation necessary to attract and retain executives. Base salary levels are established based on data from the Benchmarking Peer Group identified above and consideration of each executive officer's skills, experience, responsibilities and performance. Market compensation levels are used to assist in establishing each executive's job value (commonly called the "midpoint" at other companies). Job values serve as the market reference for determining base salaries.

Each year, the compensation consultant provides the market values for our executive officer positions. Based, in part, on these market values and, in part, on the executives' achievement of individual and Company goals, the Chief Executive Officer then recommends to the Committee base salary adjustments for our executive officers (excluding himself). The Committee reviews the proposed base salaries, adjusts them as it deems appropriate based on the executives' achievement of individual and Company goals and market trends that result in changes to job values, and approves them in the first quarter of each year. The Committee meets in executive session with the compensation consultant to review and establish the Chief Executive Officer's base salary.

The Committee's compensation philosophy is to consider market values near the 50th percentile of the Benchmarking Peer Group. The Committee may choose to set base salaries at a higher percentile of the market to address such factors as competition, retention, succession planning, and the uniqueness and complexity of a position; however, on average, base salaries of the named executive officers for 2009 were approximately 10% below those of the Benchmarking Peer Group. While our current named executive officers have significant experience and tenure with the Company, they, as a group, do not have significant tenure in their current positions. The Committee expects that over time, the average base salary percentile will continue to target the market median. We discuss how individual named executive officers' base salaries compare to the targeted benchmark in "2009 COMPENSATION DECISIONS" on page 40 below.

2. ANNUAL INCENTIVE

We sponsor the MICP, an annual cash incentive plan, in which our executives, managers and supervisors participate. The Company includes managers and supervisors in the MICP to increase accountability for all levels of the Company's management team and to better align compensation with management performance. Annual incentive opportunities are provided to executive officers to promote the achievement of annual performance objectives. MICP targets are based on a percentage of each executive's base salary and are intended to offer target award opportunities that approximate the 50th percentile of the market for Benchmarking Peer Group. For 2009, all MICP targets for our named executive officers were at or below the 50th percentile.

Each year, the Committee establishes the threshold, target and outstanding levels for the performance measures applicable to the named executive officers. The 2009 MICP performance measures were ongoing earnings per share (EPS) and business unit EBITDA for PEC and PEF as shown in the table below:

MICP Financial Performance Goals			
(in millions except EPS)	Threshold	Target	Outstanding
Company EPS	$2.86	$3.06	$3.16
PEC EBITDA	$1,630	$1,685	$1,715
PEF EBITDA	$1,060	$1,100	$1,115

The MICP's performance targets are designed to align with our financial plan and are intended to appropriately motivate the executive officers to achieve the desired corporate financial objectives. The potential MICP funding for each performance measure is 50% at threshold, 100% at target and 200% at outstanding (maximum). Interpolation occurs when actual performance is between the identified levels. Each performance measure is assigned a weight based on the relative importance of that measure to the Company's performance. During the year, updates are provided to the Committee on the Company's performance as compared to the performance measures. Effective January 1, 2010, the legal entity EBITDA performance measure was replaced by legal entity net income. This new performance measure was implemented as a result of the Company's desire to increase its legal entity focus on net income results. Net income results include certain regulatory decisions and key costs that are part of achieving EPS targets in managing a capital-intensive utility business.

The determination of the annual MICP award that each named executive officer receives has two steps: 1) funding the MICP awards based on the performance as compared to the financial goals specified above; and 2) determining individual MICP awards. First, the Committee determines the total amount that will be made available to fund MICP awards to managers and executives, including the named executive officers. To determine the total amount available to fund all MICP awards, we calculate an amount for each MICP participant by multiplying each participant's base salary by a performance factor (based on the sum of a participant's weighted target award achievements). The performance factor ranges between 0 and 200% of a participant's target award, depending upon the results of each applicable performance measure. The sum of these amounts for all participants is the total amount of funds available to pay to all participants, including the named executive officers. For 2009, the named executive officers' performance measures under the MICP were weighted among earnings per share and EBITDA as follows:

Named Executive Officer	Target Opportunity	Performance Measures (Relative Percentage Weight)		
		Company Earnings Per Share	PEC EBITDA	PEF EBITDA
William D. Johnson	85%	100%	—	—
Mark F. Mulhern	55%	100%	—	—
Jeffrey J. Lyash (through July 5, 2009)	55%	45%	—	55%
Jeffrey J. Lyash (effective July 6, 2009)[1]	55%	35%	32.5%	32.5%
Lloyd M. Yates	55%	45%	55%	—
Paula J. Sims	45%	35%	32.5%	32.5%

[1] Mr. Lyash's performance measure opportunities and relative weights under the MICP were adjusted effective July 6, 2009, to reflect his becoming the Company's Executive Vice President – Corporate Development.

Second, the Committee utilizes discretion to determine the MICP award to be paid to each executive. This determination is based on the executive's target award opportunity, the degree to which the Company achieved certain goals, and the executive's individual performance based on achieving individual goals and operating results.

As allowed by the MICP, the Committee uses discretion to adjust funding amounts up or down depending on factors that it deems appropriate, such as storm costs and other nonrecurring items including impairments, restructuring costs, and gains/losses on sales of assets. The Committee uses ongoing earnings per share as defined and reported by the Company in its annual earnings release. Based on management's recommendations, with respect to 2009, the Committee exercised discretion for the three performance measures—earnings per share, PEC EBITDA, and PEF EBITDA. The Committee approved adjusting earnings per share results upward by $0.04 to account for storm costs and investment gains on certain employee benefit trusts. The Committee approved adjusting the PEC EBITDA results for the decline in residential, commercial, and industrial retail usage due to weak economic conditions, favorable weather, and storm costs for a net upward adjustment of $72 million. The Committee also approved adjusting the PEF EBITDA downward by $52 million to reflect the impact of favorable weather and pension expense amortization. These adjustments resulted in earnings per share, PEC EBITDA and PEF EBITDA performance at 93%, 68% and 107% of target, respectively.

The Committee may reduce but cannot increase the amount payable to a participant according to business factors determined by the Committee, including the performance measures under the MICP. Awards are earned based upon the achievement of performance measures approved by the Committee under the MICP.

3. LONG-TERM INCENTIVES

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

The Committee has determined that to accomplish our compensation program's purposes effectively, equity-based awards should consist of one-third restricted stock units and two-thirds performance shares. This allocation reflects the Committee's strategy of utilizing long-term incentives to retain officers, align officers' interests with those of the Company's shareholders and drive specific financial performance. Performance shares are intended to focus executive officers on the multi-year sustained achievement of financial and shareholder value objectives. Restricted stock units are service-based and provide an opportunity for the executive officer's interests to be further aligned with shareholder interests if the executive remains with the Company long enough for the restricted stock units to vest.

The table below shows the 2009 long-term incentive targets for each of the named executive officer's positions.

Long-Term Incentive Award Target[1]

	Performance Shares Target Award	Restricted Stock Units Target Award
Position[2]	**2009**	**2009**
Chief Executive Officer	233%	117%
Executive Vice President	117%	58%
Chief Financial Officer	117%	58%
Presidents, PEC and PEF	117%	58%
Senior Vice Presidents	100%	50%

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

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

In determining long-term incentive targets, the Committee may choose to establish targets at a higher percentile of the market to address such factors as competition, retention, succession planning and the uniqueness and complexity of a position; however, on average, the targets established for the named executive officers for 2009 were 15% lower than comparable aggregate long-term incentive opportunities of our peer group. The Committee expects that, over time, the long-term incentive opportunities will continue to approximate the 50th percentile of the peer group. We discuss how individual named executive officers' long-term incentive targets compared to the targeted benchmarks in "2009 COMPENSATION DECISIONS" on page 40 below. Grants of equity-based awards typically occur in the first quarter, after the annual earnings release. This timing allows current financial information to be fully disclosed and publicly available prior to any grants.

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

Performance Shares

The PSSP authorizes the Committee to issue performance shares to executives as selected by the Committee in its sole discretion. The value of a performance share is equal to the value of a share of the Company's common stock, and earned performance share awards are paid in Company common stock. The performance period for a performance share is the three-consecutive-calendar-year period beginning in the year in which it is granted. The closing stock price on the last trading day of the year prior to the beginning of the performance period is used to calculate the number of performance shares granted to each participant in that performance period. The Committee may exercise discretion in determining the size of each performance share grant, with the maximum grant size at 125% of target. In 2009, the Committee did not exercise this discretion with respect to any grant of the named executive officers.

2007 Performance Share Sub-Plan

The PSSP, as redesigned in 2007 (the "2007 PSSP"), provides for an adjusted measure of total shareholder return to be utilized as the sole measure for determining the amount of a performance share award upon vesting. The Committee and management designed the total shareholder return performance measure to be calculated assuming a constant price to earnings ratio, which was set at the beginning of each performance period. The performance measure also uses the Company's publicly reported ongoing earnings as the earnings component for determining performance share awards. The Committee chose this method, which we will refer to as "Total Business Return," as the sole performance measure to support its desire to better align the long-term incentives with the interests of our shareholders and to emphasize our focus on dividend and earnings per share growth. The performance measure for the 2007 and 2008 performance share grants made under the 2007 PSSP are shown in the table below.

	Threshold	Target	Outstanding
2007 Total Business Return*	5%	8%	≥10.5%
2007 Percentage of Target Award Earned	50%	100%	200%
2008 Total Business Return*	5%	8%	≥11%
2008 Percentage of Target Award Earned	25%	100%	200%

* Total shareholder return, adjusted to reflect a constant price to earnings ratio set at January 1 of the grant year and to reflect the Company's ongoing earnings per share for each year of the performance period.

Additionally, the Committee retained the discretion to reduce the number of performance shares awarded if it determines that the payouts resulting from the Total Business Return do not appropriately reflect the Company's actual performance.

In 2007, the Committee approved a transition plan designed to bridge the prior long-term incentive plan to the redesigned long-term incentive plan. Under the transition plan, the Committee awarded interim grants of performance units to our officers (the "Transitional Grants"). The Transitional Grants were determined using the same Total Business Return measure as the annual grants described above.

The Transitional Grants included a grant that vested in 2009. The size of the grant awarded to each of the named executive officers was equal to such officer's revised PSSP long-term incentive target for 2007. The transition plan provides that any award from the Transitional Grants vesting in 2009 will be reduced by awards, if any, from the outstanding 2006 performance share grants vesting in 2009. Based on the performance results calculated under the terms of the 2006 PSSP, the Company did not make a payment in 2009 in connection with the performance shares that were issued in 2006. Under the terms of the Transitional Grants, the actual payout opportunity ranges from 0% to 200% of the grant, based on performance. In 2009, the Committee approved a payout of 100% of the target value for the Transitional Grant that vested in 2009.

2009 Performance Share Sub-Plan (the "2009 PSSP")

In early 2009, the Committee, along with its executive compensation consultant, concluded that the PSSP should be modified to further align it with the prevailing structure of long-term incentive plans of other highly regulated utility companies and to improve its alignment with the Company's goals. The 2009 PSSP continues to be based on a three-year performance period, and performance shares accrue quarterly dividend equivalents, which are reinvested in additional shares. Shares vest on January 1 following the end of the performance period and are paid out in Company common stock provided the performance measures have been met.

The modifications to the 2009 PSSP use two equally weighted performance measures: relative total shareholder return (TSR) and earnings growth. By using a combination of relative (TSR) and absolute (earnings growth) performance measures, the 2009 PSSP allows the Committee to consider the Company's performance as compared to the PSSP Peer Group (as defined below), and management's achievement of internal goals. TSR is defined as the appreciation or depreciation in the value of the stock, plus dividends paid during the year, divided by the closing value of the stock on the last trading day of the preceding year. The relative TSR performance is calculated using the Company's three-year annualized TSR ranked against the PSSP Peer Group (as defined below). This component of the PSSP award is based on the Company's relative TSR percentile ranking. However, regardless of the relative ranking, if the Company's TSR is negative for the performance period, no award above the threshold can be earned. The table below shows the percent of target awards that may be earned based on the Company's relative TSR percentile ranking:

Performance and Award Structure (50%)	
Percentile Ranking	**Percent of Target Award Earned**
80th	200%
50th	100%
40th	50%
<40th	0%

The Committee selected a peer group for the PSSP awards comprised of highly regulated companies with a business strategy similar to ours based on a percentage of regulated earnings (the "PSSP Peer Group"). These companies have a significant amount of their earnings generated from regulated assets. In addition, the PSSP Peer Group was selected based on other factors including revenues, market capitalization, enterprise value and percent of regulated earnings. The table below lists the companies in the PSSP Peer Group.

Alliant Energy Corporation	Great Plains Energy, Inc.	SCANA Corporation
American Electric Power, Inc.	NV Energy, Inc.	Southern Company
Consolidated Edison, Inc.	PG&E Corporation	Westar Energy, Inc.
DPL, Inc.	Pinnacle West Capital Corporation	Wisconsin Energy Corp.
Duke Energy Corporation	Portland General Electric Company	Xcel Energy, Inc.

The PSSP Peer Group differs from the Benchmarking Peer Group the Committee uses for purposes of benchmarking compensation. The Benchmarking Peer Group is a broader group that represents those companies with which we primarily compete for executive talent and includes companies that are not regulated integrated utilities. The Committee believes that for purposes of our long-term incentive plan, it is more appropriate to use the PSSP Peer Group comprised of companies that derive a significant percentage of their earnings from regulated businesses.

Earnings growth is based on the Company's ongoing annual EPS. The ongoing EPS is determined in accordance with the Company's "Policy for Press Release Earnings Disclosure." The earnings growth component of the PSSP award is based on the Company's earnings growth performance as measured against pre-established goals set at the beginning of the performance period. The table below shows the percent of target awards that may be earned based on the Company's earnings growth performance:

Performance and Award Structure (50%)		
Performance	**Three-Year Average Ongoing EPS Growth**	**Percent of Target Award Earned**
Threshold	2%	50%
Target	4%	100%
Maximum	6%	200%

Restricted Stock and Restricted Stock Units

The restricted stock component of the current long-term incentive program helps us retain executives and aligns the interests of management with those of our shareholders and management by rewarding executives for increasing shareholder value. In 2007, the Committee began issuing restricted stock units rather than restricted stock. The restricted stock units provide the same incentives and value as restricted stock, but are more flexible and cost effective for the Company. Executive officers typically receive a grant of service-based restricted stock units in the first quarter of each year which are subject to a three-year graded vesting schedule. The size of each grant is based on the executive officer's target and determined using the closing stock price on the last trading day prior to the Committee's action. The Committee establishes target levels based on the peer group information discussed under the caption "Competitive Positioning Philosophy" on page 26 above. The 2009 restricted stock unit targets for the named executive officer positions are shown in the "Long-Term Incentive Award Target" table on page 31 above. The restricted stock units pay quarterly cash dividend equivalents equal to the amount of any dividends paid on our common stock. The Committee believes that the service-based nature of restricted stock units is effective in retaining an experienced and capable management team.

To further accent the retention quality of the Equity Incentive Plan and to recognize the contribution of the officer team, including the named executive officers, the Committee may also issue in its discretion service-based ad hoc grants of restricted stock units to executives. Ad hoc grants awarded by the Committee during 2009 are discussed in "2009 COMPENSATION DECISIONS" on page 40 below.

4. SUPPLEMENTAL SENIOR EXECUTIVE RETIREMENT PLAN

The Supplemental Senior Executive Retirement Plan ("SERP") provides a supplemental, unfunded pension benefit for executive officers who have at least 10 years of service and at least three years of service on our Senior Management Committee. Currently, 11 executive officers participate in the SERP. The SERP is designed to provide pension benefits above those earned under our qualified pension plan. Current tax laws place various limits on the benefits payable under our qualified pension, including a limit on the amount of annual compensation that can be taken into account when applying the plan's benefit formulas. Therefore, the retirement incomes provided to the named executive officers by the qualified plans generally constitute a smaller percentage of final pay than is typically the case for other Company employees. To make up for this shortfall and to maintain the market-competitiveness of the Company's executive retirement benefits, we maintain the SERP for executive officers, including the named executive officers.

The SERP defines covered compensation as annual base salary plus the annual cash incentive award. The qualified plans define covered compensation as base salary only. The Committee believes it is appropriate to include annual cash incentive awards in the definition of covered compensation for purposes of determining pension plan benefits for the named executive officers to ensure that the named executive officers can replace in retirement a similar portion of total compensation as replaced for other employees who participate in the Company's pension plan. This approach takes into account the fact that base pay alone comprises a relatively smaller percentage of a named executive officer's total compensation than of other Company employees' total compensation.

The Committee believes that the SERP is a valuable and effective tool for attraction and retention due to its vesting requirements and its significant benefit. It is also a common tool among the Benchmarking Peer Group and utilities in general. Total years of service attributable to an eligible executive officer may consist of actual or deemed years. The Committee grants deemed years of service on a case-by-case basis depending upon our need to attract and retain a particular executive officer. All of our named executive officers are fully vested in the SERP.

Payments under the SERP are made in the form of an annuity, payable at age 65. The monthly SERP payment is calculated using a formula that equates to 4% per year of service (capped at 62%) multiplied by the average monthly eligible pay for the highest completed 36 months of eligible pay within the preceding 120-month period. Eligible pay includes base salary and annual incentive. (For those executives who became SERP participants on or after January 1, 2009, the target benefit percentage is 2.25% rather than 4% per year of service. None of the named executive officers for 2009 is subject to the new benefit percentage.) Benefits under the SERP are fully offset by Social Security benefits and by benefits paid under our qualified pension plan. An executive officer who is age 55 or older with at least 15 years of service may elect to retire and commence his or her SERP benefit prior to age 65. The early retirement benefit will be reduced by 2.5% for each year the participant receives the benefit prior to reaching age 65.

5. MANAGEMENT CHANGE-IN-CONTROL PLAN

We sponsor a Management Change-In-Control Plan (the "CIC Plan") for selected employees. The purpose of the CIC Plan is to retain key management employees who are critical to the negotiation and subsequent success of any transition resulting from a change-in-control ("CIC") of the Company. Providing such protection to executive officers in general minimizes disruption during a pending or anticipated CIC. Under our CIC Plan, we generally define a CIC as occurring at the earliest of the following:

- the date any person or group becomes the beneficial owner of 25% or more of the combined voting power of our then outstanding securities; or
- the date a tender offer for the ownership of more than 50% of our then outstanding voting securities is consummated; or
- the date we consummate a merger, share exchange or consolidation with any other corporation or entity, regardless of whether we are the surviving company, unless our outstanding securities immediately prior to the transaction continue to represent more than 60% of the combined voting power of the outstanding voting securities of the surviving entity immediately after the transaction; or
- the date, when, as a result of a tender offer, exchange offer, proxy contest, merger, share exchange, consolidation, sale of assets or any combination of the foregoing, the directors serving as of the effective date of the change-in-control plan, or elected thereafter with the support of not less than 75% of those directors, cease to constitute at least two-thirds (⅔) of the members of the Board of Directors; or
- the date that our shareholders approve a plan of complete liquidation or winding-up or an agreement for the sale or disposition by us of all or substantially all of our assets; or

- the date of any other event that our Board of Directors determines should constitute a CIC.

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

- focus executives on maximizing shareholder value;
- ensure business continuity during a transition and thereby maintain the value of the acquired company;
- allow executives to focus on their jobs by easing termination concerns;
- demonstrate the Company's commitment to its executives;
- reward executives for their role in executing a transition and, if appropriate, align awards with the new company's performance;
- recognize the additional stress, efforts and responsibilities of employees during periods of transition; and
- keep executives in place and provide them with severance only if a CIC transaction is completed.

The Committee has the sole authority and discretion to designate employees and/or positions for participation in the CIC Plan. The Committee has designated certain positions, including all of the named executive officer positions, for participation in the CIC Plan. Participants are not eligible to receive any of the CIC Plan's benefits absent both a CIC of the Company and an involuntary termination of the participant's employment without cause, including voluntary termination for good reason. Good reason termination includes changes in employment circumstances such as:

- a reduction of base salary or incentive targets;
- certain reductions in position or scope of authority;
- a significant change in work location; or
- a breach of provisions of the CIC Plan.

Rather than allowing benefit amounts to be determined at the discretion of the Committee, the CIC Plan has specified multipliers designed to be attractive to the executives and competitive with current market practices. With the assistance of its executive compensation and benefits consultant, the Committee has reviewed the benefits provided under the CIC Plan to ensure that they meet the Company's needs, are reasonable and fall within competitive parameters. The Committee has determined that the current multipliers are needed for the CIC Plan to be effective at meeting the goals described above.

The CIC Plan provides separate tiers of severance benefits based on the position a participant holds within our Company. The continuation of health and welfare benefits coverage and the degree of excise tax gross-up for terminated participants align with the length of time during which they will receive severance benefits.

The following table sets forth the key provisions of the CIC Plan benefits as it relates to our named executive officers:

	Tier I	Tier II
Eligible Positions	Chief Executive Officer, Chief Operating Officer, Presidents and Executive Vice Presidents	Senior Vice Presidents
Cash Severance	300% of base salary and annual incentive[1]	200% of base salary and annual incentive[1]
Health & Welfare Coverage Period	Coverage up to 36 months	Coverage up to 24 months
Gross-ups	Full gross-up of excise tax	Conditional gross-up of excise tax

[1] The cash severance payment will be equal to the sum of the applicable percentage of annual base salary and the greater of the average of the participant's annual incentive award for the three years immediately preceding the participant's employment termination date, or the participant's target annual incentive award for the year the participant's employment with the Company terminates.

Additionally, the following benefits are potentially available to named executive officers upon a CIC.

Benefit	Description
Annual Incentive	100% of target incentive in year of CIC
Restricted Stock Agreements	Restrictions are fully waived on all outstanding grants upon termination
Performance Share Sub-Plan	Outstanding awards vest as of the termination date
Stock Option Agreements	Rights dependent upon whether option has been assumed by successor
Supplemental Senior Executive Retirement Plan	Participant shall be deemed to have met minimum service requirements for benefit purposes, and participant shall be entitled to payment of benefit under the SERP
Deferred Compensation	Entitled to payment of accrued benefits in all accrued nonqualified deferred compensation plans
Split-Dollar Life Insurance Policies[1]	We pay all premiums due under a split-dollar life insurance arrangement under which the terminated participant is the insured for a period not to exceed the applicable period of either 36 (Tier I) or 24 (Tier II) months

[1] Prior to 2003, we sponsored an executive split-dollar life insurance program. The plan provided life insurance coverage approximately equal to three times salary for executive officers. During 2003, we discontinued our executive split-dollar program for all future executives and discontinued our payment of premiums on existing split-dollar policies for senior executives in response to the Internal Revenue Service's final split-dollar regulations and the Sarbanes-Oxley Act of 2002. In 2008 the Committee authorized the Chief Executive Officer to terminate the executive split-dollar program. The Plan was terminated effective January 1, 2009. All named executive officers surrendered their policies for cash value. Surrender proceeds were issued in January 2009.

In the event of a change-in-control of the Company, each named executive officer can receive the greater of benefits provided under the CIC Plan or severance benefits provided under his employment agreement, but not both. The tables captioned "Potential Payments Upon Termination," on pages 59 through 68 below show the potential payments each of our named executive officers would receive in the event of a CIC.

The CIC Plan also permits the Board to establish a nonqualified trust to protect the benefits of the impacted participants. This type of trust generally is established to protect nonqualified and/or deferred compensation against various risks such as a CIC or a management change-of-heart. Any such trust the Board establishes will be irrevocable and inaccessible to future or current management, and may be currently funded. To date, no such trust has been funded with respect to any of our named executive officers.

6. EMPLOYMENT AGREEMENTS

Each named executive officer has an employment agreement that documents the Company's relationship with that executive. We provide these agreements to the executives as a means of attracting and retaining them. Each agreement has a term of three years. When an agreement's remaining term diminishes to two years, the agreement automatically adds another year to the term, unless we give 60-days advance notice that we do not want to extend the agreement. If a named executive officer is terminated without cause during the term of the agreement, he is entitled to severance payments equal to his base salary times 2.99, as well as up to 18 months of COBRA reimbursement. A description of each named executive officer's employment agreement is discussed under the "Employment Agreement" section of the "Discussion of Summary Compensation Table and Grants of Plan-Based Awards Table" on page 50 of this Proxy Statement.

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

7. EXECUTIVE PERQUISITES

We provide certain perquisites and other benefits to our executives. Amounts attributable to perquisites are disclosed in the "All Other Compensation" column of the Summary Compensation Table on page 45.

During 2009, the Committee evaluated the perquisites program to determine whether it was competitive and consistent with the Company's compensation philosophy. As a result of this evaluation, the Committee determined that the current perquisites were appropriate and consistent with market practices. The perquisites available to the named executive officers during 2009 include:

Perquisites for 2009	Description
Personal Travel on Corporate Aircraft and "Business-Related" Spousal Travel[1]	Personal and spousal travel on corporate aircraft is permitted under very limited circumstances.
Financial and Estate Planning	An annual allowance of up to $16,500 for the purpose of purchasing financial and estate planning counseling and services and preparation of personal tax return.
Luncheon and Health Club Dues	Membership in an approved luncheon club and membership in a health club of executive officer's choice.
Executive Physical	Reimbursement of up to $2,500 for an extensive physical at a clinic specializing in executive physicals, every other year.
Internet and Telecom Service[2]	Monthly fees for Internet and telecom access.
Home Security	An installed home security system and payment of monitoring fees.
Accidental Death and Dismemberment Insurance	$500,000 of AD&D insurance for each executive officer.

[1] Personal travel on the Company's aircraft in the event of a family emergency or similar situation is permitted with the approval of the Chief Executive Officer. Executives' spouses may travel on the Company's aircraft to accompany the executives to "business-related" events executives' spouses are requested to attend. For 2009, the named executive officers whose perquisites included spousal travel on corporate aircraft for business purposes were Messrs. Lyash and Yates.

[2] Including home use of Company-owned computer.

The Committee believes that the perquisites we provide to our executives are reasonable, competitive and consistent with our overall executive compensation program in that they help us attract and retain skilled and qualified executives. We believe that these benefits generally allow our executives to work more efficiently and, in the case of the tax and financial planning services, help them to optimize the value received from all of the compensation and benefits programs offered. The costs of these benefits constitute only a small percentage of each named executive officer's total compensation.

8. OTHER BROAD-BASED BENEFITS

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

- participation in our 401(k) Plan (including a limited Company match of up to 6% of eligible compensation);
- participation in our funded, tax-qualified, noncontributory defined-benefit pension plan, which uses a cash balance formula to accrue benefits; and
- general health and welfare benefits such as medical, dental, vision and life insurance, as well as long-term disability coverage.

9. DEFERRED COMPENSATION

We sponsor the Management Deferred Compensation Plan (the "MDCP"), an unfunded, deferred compensation arrangement. The plan is designed to provide executives with tax deferral options, in addition to those available under the existing qualified plans. An executive may elect to defer, on a pre-tax basis, payment of up to 50% of his or her salary for a minimum of five years or until his or her date of retirement. As a make-up for the 401(k) statutory compensation limits, executives receive deferred compensation credits of 6% of their base salary over the Internal Revenue Code statutory compensation limit on 401(k) retirement plans. The Committee views the matching feature as a restoration benefit designed to restore the matching contribution the executive would have received under the 401(k) retirement plan in the absence of the Internal Revenue Service compensation limits. These Company matching allocations are allocated to an account that will be deemed initially to be invested in shares of a stable value fund within the MDCP. Each executive may reallocate his or her deferred compensation among the other available deemed investment funds that mirror those options available under the 401(k) plan.

Executives can elect to defer up to 100% of their MICP and/or performance share awards. The deferral option is provided as an additional benefit to executive officers to provide flexibility in the receipt of compensation. Historically, all deferred awards were deemed to be invested in performance units, generally equivalent to shares of the Company's common stock and received a 15% discount to the Company's then-current common stock price. Beginning January 1, 2009, the discount feature was eliminated and deferred awards may be allocated among investment options that mirror the Company's 401(k) Plan.

III. 2009 COMPENSATION DECISIONS

Company Performance

The Committee made decisions for the executive officers' compensation following the process described above. The Committee noted that under the leadership of our executive officer management team, the Company reported solid financial and operating results in 2009 despite the challenging economic and regulatory environment. Highlights of the Company's 2009 performance include the following:

- Returned value to shareholders including increasing dividends from $642 million in 2008 to $693 million in 2009; dividend payments increased for the 21st consecutive year;
- Total shareholder return in 2009 was 10.4% as compared to the average 2009 total shareholder return for the Benchmarking Peer Group of 9.66%; the Company's 3-year total shareholder return was -0.53% as compared to the average 3-year total shareholder return for the Benchmarking Peer Group of -5.27%;
- Delivered ongoing earnings of $846 million, or $3.03 per share, compared to $776 million, or $2.96 per share in 2008;
- Received approval from the Florida Public Service Commission ("FPSC") to increase base rates by $132 million; the Committee acknowledges that this increase represents only 26% of the Company's request and believes the result was due to the FPSC's unwillingness to meaningfully raise consumer rates in the particularly challenging Florida economic environment;
- Received final orders from the FPSC for all of PEF's proposed 2010 recovery for fuel, environmental and energy-efficiency costs; and
- Filed with the North Carolina Utilities Commission ("NCUC") a plan to retire by the end of 2017 the remaining 11 North Carolina coal-fired units that do not have flue-gas desulfurization controls (scrubbers) and filed a corresponding plan to build a 600-megawatt (MW) natural gas-fired plant to replace the coal-fired units at our Sutton Plant in conjunction with their retirement in 2014; the Sutton Plant project would represent an estimated investment of approximately $600 million and significantly reduce overall emissions.

Chief Executive Officer Compensation

William D. Johnson

In March 2009, the Committee considered Mr. Johnson's salary against the salaries of the chief executive officers in the Benchmarking Peer Group, the Company's performance, and the difficult external economic and regulatory climate. Based on these factors, the Committee approved a salary of $990,000 for Mr. Johnson representing an increase of 4.2% to his 2008 salary. Mr. Johnson's current target total base compensation is approximately 18% below the 50th percentile of the Benchmarking Peer Group due to his relatively short tenure in the Chief Executive Officer position, and more significantly, the challenging economic and regulatory environment. It is the Committee's intention to increase Mr. Johnson's salary over time to a level that is at the 50th percentile of the Benchmarking Peer Group. For 2009, the Committee set Mr. Johnson's MICP target award at 85% of base salary. This target award was the same as the target Mr. Johnson had in 2007 after he assumed his new position, and represents a target award opportunity that is below the 50th percentile of market. The payout of the 2009 MICP award was based on the extent to which Mr. Johnson achieved his performance goals, which were focused on the following general areas of Company success:

- Delivering on fundamentals of safety, operational excellence and customer satisfaction;
- Achieving financial objectives;

- Managing capital projects effectively;
- Executing the energy-efficiency and emerging technology features of the Company's Balanced Solution Strategy;
- Achieving reasonable outcome on PEF's 2010 base rate proceeding filed in March 2009;
- Advocating effectively for achievable, affordable climate and renewable energy policies; and
- Strengthening leadership focus on employee engagement, communication, diversity and inclusion.

In recognition of his accomplishments during 2009, including his leadership in achieving the Company Performance described above, the Committee awarded Mr. Johnson an MICP payout of $950,000, which is equal to 114% of Mr. Johnson's target award. The Committee also considered Mr. Johnson's emphasis on specific leadership behaviors and expectations throughout the year which were communicated to the Company's management team in clear and direct terms. The Committee also noted Mr. Johnson's active leadership in key national industry organizations, including frequent, direct engagement with policymakers and regulators at the federal and state levels.

With respect to his long-term incentive compensation during 2009, Mr. Johnson was granted 27,892 restricted stock units and 55,546 performance shares in accordance with his pre-established targets of 117% and 233%, respectively, of his base salary. The performance shares are earned based on performance over the three years ending December 31, 2011. Additionally, 29,456 shares of the 2007 annual grant vested in 2009 and were paid out at 100% of target. The Committee also issued to Mr. Johnson an ad hoc retention grant of 8,000 restricted stock units to recognize his leadership in the critical position of Chief Executive Officer, outstanding performance against objectives and the manner in which he achieved those objectives. Total year-over-year compensation to Mr. Johnson for 2009, as compared to 2008, as noted in the "Summary Compensation Table" on page 45 of this Proxy Statement, was relatively flat.

Chief Financial Officer Compensation

Mark F. Mulhern

In March 2009, Mr. Johnson recommended and the Committee approved a base salary of $425,000 for Mr. Mulhern, representing a 10.4% increase to his previous salary of $385,000. The new base salary was set at 20% below the 50th percentile of the Benchmarking Peer Group. Mr. Mulhern's base salary was established at this level due to his relatively short tenure in the Chief Financial Officer position, and more significantly, the challenging economic and regulatory environment. It is the Committee's intention to increase Mr. Mulhern's salary over time to a level that is at the 50th percentile of the Benchmarking Peer Group.

For 2009, Mr. Mulhern's MICP target award was set at 55% of his base salary. This target award is the same target Mr. Mulhern had in 2008 after he assumed the Chief Financial Officer position and represents a target award opportunity that is below the 50th percentile of the market. Mr. Mulhern's performance goals for 2009 focused on the following general areas of Company success:

- Achieving financial objectives;
- Developing a pension funding strategy and communicating it effectively to the investment community;
- Achieving reasonable outcome on PEF's rate settlement with respect to 2006-2008 expenditures; and
- Strengthening leadership focus on employee engagement, communication, diversity and inclusion.

In recognition of the achievements he accomplished in 2009 and on Mr. Johnson's recommendation, the Committee awarded Mr. Mulhern an MICP payout of $225,000, which is equal to 99% of Mr. Mulhern's target award. Mr. Mulhern's award was due in part to his leadership in the Company achieving its EPS goal, execution of a funding strategy for the pension plan, and obtaining interim rate relief for PEF.

With respect to his long-term incentive compensation, in 2009, Mr. Mulhern was granted 5,604 restricted stock units and 11,304 performance shares in accordance with his pre-established targets of 58% and 117%, respectively, of base salary. The performance shares are earned based on performance over the three years ending December 31, 2011. Additionally, 7,131 shares of the 2007 annual grant vested in 2009 and were paid out at 100% of target. On Mr. Johnson's recommendation, the Committee also issued to Mr. Mulhern an ad hoc retention grant of 2,500 restricted stock units to recognize his leadership in the critical position of Chief Financial Officer, his outstanding performance against objectives and the manner in which he achieved those objectives. The decrease in year-over-year total compensation to Mr. Mulhern for 2009, as compared to 2008, as noted in the "Summary Compensation Table" on page 45 of this Proxy Statement, was largely due to vesting of the total accumulated SERP benefit that occurred in 2008.

Compensation of Other Named Executive Officers

For 2009, Mr. Johnson recommended and the Committee approved base salaries for Messrs. Lyash and Yates of $453,000 and $448,000, respectively. The base salaries for Messrs. Lyash and Yates represented an increase of approximately 1.80% and 1.82%, respectively, above their 2008 salaries. The new base salaries are set at 9% below the 50th percentile of the market. The modest year-over-year increase to Mr. Lyash's and Mr. Yates' salaries reflects the Committee's and management's recognition of the challenging economic and regulatory environment. It is the Committee's intention to increase Messrs. Lyash's and Yates' salaries over time to a level that is at the 50th percentile of the Benchmarking Peer Group.

For 2009, Mr. Johnson recommended and the Committee approved Ms. Sims' base salary to remain at $370,000. The 2009 base salary is set at 11% above the 50th percentile of the Benchmarking Peer Group due to Ms. Sims' extensive knowledge of fuel and power operations.

Mr. Lyash received standard assistance with relocation expenses in connection with the Company's requirement that he relocate from Florida to North Carolina to assume his current position. Mr. Lyash also received assistance with the sale of his Florida home. For more information, see note 16 to the "Summary Compensation Table" on page 45.

On Mr. Johnson's recommendation, the Committee awarded Messrs. Lyash and Yates and Ms. Sims 2009 MICP awards as described in the table below.

Named Executive Officer	2009 MICP Award	Percent of Target	Explanation of Award
Jeffrey J. Lyash	$235,000	95%	Mr. Lyash played a significant role in mitigating a substantial reduction in PEF's retail revenue through a combination of O&M reductions, wholesale contracts and rate mitigation resulting in PEF's attaining its earnings goals; completion of the Bartow Plant repowering that is reflected in rates; and implementation of project oversight process.
Lloyd M. Yates	$235,000	96%	Mr. Yates played a significant role in the Company's achievement of its EPS goal and PEC's achievement of its capital spending budget goal; led development of fleet modernization strategy to replace coal-fired plants with natural gas-fired plants; execution of wholesale expansion and renewal contracts on favorable terms; and development of effective relationships in the regulatory and legislative arenas resulting in passage of significant legislation in North Carolina.
Paula J. Sims	$160,000	96%	Ms. Sims played a significant role in the Power Operation Group's achievement of its O&M and capital spending goals; led the Continuous Business Excellence effort to obtain sustainable 3-5% productivity gains; implementation of a strategy to reduce emissions by replacing coal-fired plants with natural gas-fired plants; and increased the focus on safety by reducing our OSHA injury rate.

With respect to long-term compensation, in 2009 each of the other named executive officers received annual grants of restricted stock units and performance shares in accordance with their pre-established targets. The table below describes those grants, the transitional performance share grants that the Committee issued in 2007, and the ad hoc restricted stock unit grants.

Named Executive Officer	Restricted Stock Units Vesting in 1/3 Increments in 2010, 2011 and 2012	Transitional Performance Shares Vesting 2009	Performance Shares Vesting 2012	Ad Hoc Restricted Stock Units Vesting 2012
Jeffrey J. Lyash	6,477	9,535	13,065	2,000
Lloyd M. Yates	6,404	9,535	12,918	2,000
Paula J. Sims	4,642	7,131	9,285	2,000

The increase in total compensation to Mr. Lyash, as compared to 2008, as noted in the "Summary Compensation Table" on page 45 of this Proxy Statement, was largely due to the increase in his equity grants value and the receipt of relocation expenses and assistance with the sale of his Florida home.

The decrease in year-over-year total compensation to Mr. Yates, as compared to 2008, as noted in the "Summary Compensation Table" on page 45 of this Proxy Statement, was largely due to vesting of the total accumulated SERP benefit that occurred in 2008.

The significant increase in year-over-year total compensation to Ms. Sims, as compared to 2008, as noted in the "Summary Compensation Table" on page 45 of this Proxy Statement, was largely due to her vesting in the SERP in 2009.

IV. COMPENSATION COMMITTEE REPORT

The Committee has reviewed and discussed this CD&A with management as required by Item 402(b) of Regulation S-K. Based on such review and discussions, the Committee recommended to the Company's Board of Directors that the CD&A be included in this Proxy Statement.

Organization and Compensation Committee

E. Marie McKee, Chair
John D. Baker II
Harris E. DeLoach, Jr.
James B. Hyler, Jr.
Robert W. Jones
John H. Mullin, III

Unless specifically stated otherwise in any of the Company's filings under the Securities Act of 1933 or the Securities Exchange Act of 1934, the foregoing Compensation Committee Report shall not be deemed soliciting material, shall not be incorporated by reference into any such filings and shall not otherwise be deemed filed under such Acts.

SUMMARY COMPENSATION TABLE FOR 2009

The following Summary Compensation Table discloses the compensation during 2009 of our Chief Executive Officer, Chief Financial Officer, and the other three most highly paid executive officers who were serving at the end of 2009. Additionally, column (h) is dependent upon actuarial assumptions for determining the amounts included. A change in these actuarial assumptions would impact the values shown in this column. Where appropriate, we have indicated the major assumptions in the footnotes to column (h).

Name and Principal Position (a)	Year (b)	Salary[1] ($) (c)	Bonus ($) (d)	Stock Awards[2] ($) (e)	Option Awards[3] ($) (f)	Non-Equity Incentive Plan Compensation[4] ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings[5] ($) (h)	All Other Compensation[6] ($) (i)	Total[2] ($) (j)
William D. Johnson,	2009	$979,231	N/A	$3,090,605[8]	$0	$950,000	$1,144,448[9]	$289,726[10]	$6,454,010
Chairman, President and	2008	950,000		2,911,701	0	929,000	1,091,256	304,571	6,186,528
Chief Executive Officer[7]	2007	807,539		5,231,023	0	863,500	946,938	299,445	8,148,445
Mark F. Mulhern,	2009	$414,231	N/A	$655,990[11]	$0	$225,000	$369,822[12]	$102,137[13]	$1,767,180
Senior Vice President and	2008	355,385		433,473	0	200,000	820,419	141,354	1,950,631
Chief Financial Officer	2007	308,792		1,620,321	0	190,000	34,205	116,014	2,269,332
Jeffrey J. Lyash, Executive	2009	$450,846	N/A	$728,120[14]	$0	$235,000	$244,369[15]	$292,061[16]	$1,950,396
Vice President – Corporate	2008	432,885		612,952	0	225,000	323,904	140,812	1,735,553
Development (formerly	2007	386,154		2,146,232	0	265,000	272,656	125,548	3,195,590
President and Chief									
Executive Officer, PEF)									
Lloyd M. Yates,	2009	$445,846	N/A	$720,683[17]	$0	$235,000	$308,815[18]	$119,432[19]	$1,829,776
President and Chief	2008	429,231		612,952	0	210,000	777,983	155,042	2,185,208
Executive Officer, PEC	2007	374,039		2,146,232	0	265,000	26,730	127,981	2,939,982
Paula J. Sims,	2009	$370,000	N/A	$538,333[20]	$0	$160,000	$707,802[21]	$97,505[22]	$1,873,640
Senior Vice President –	2008	364,615		459,724	0	140,000	25,728	92,743	1,082,810
Power Operations	2007	324,177		1,620,321	0	170,000	21,930	108,233	2,244,661

[1] Consists of base salary earnings prior to (i) employee contributions to the Progress Energy 401(k) Savings & Stock Ownership Plan and (ii) voluntary deferrals, if any, under the Management Deferred Compensation Plan. See "Deferred Compensation" discussion in Part II of the CD&A. Salary adjustments, if deemed appropriate, generally occur in March of each year.

[2] Includes the fair value of stock awards as of the grant date computed in accordance with FASB ASC Topic 718. Assumptions made in the valuation of material stock awards are discussed in Note 9.B. to our consolidated financial statements for the year ended December 31, 2009. The values reflected for 2008 and 2007 in columns (e) and (j) are different than previously disclosed because these values represent the fair value of stock awards as of the grant date rather than the expense related to equity awards for financial statement reporting purposes in accordance with SFAS No. 123(R).

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

[4] Includes the awards given under the Management Incentive Compensation Plan (MICP) for 2007, 2008 and 2009 performance.

[5] Includes the change in present value of the accrued benefit under Progress Energy's Pension Plan, SERP, and/ or Restoration Plan where applicable. In addition, it includes the above market earnings on deferred compensation under the Deferred Compensation Plan for Key Management Employees. The current incremental present values were determined using actuarial present value factors as provided by our actuarial consultants, Buck Consultants, based on FAS mortality assumptions post-age 65 and FAS discount rates of 6.25%, 6.30%, and 6.10% for calculating the accrued benefit under the SERP for 2007, 2008, and 2009, respectively. FAS discount rates of 5.95%, 6.25%, and 5.45% were used for calculating the accrued benefits under the Restoration Retirement Plan for 2007, 2008, and 2009, respectively. FAS discount rates of 6.15%, 6.30%, and 5.95% were used for calculating the accrued benefits under the Pension Plan for 2007, 2008, and 2009, respectively. The 1996-1999 Deferred Compensation Plan for Key Management Employees provided a fixed rate of return of 10.0% on deferred amounts,

which was 2.7% above the market interest rate of 7.3% at the time the plan was frozen in 1996. The Deferred Compensation Plan for Key Management Employees was discontinued in 2000 and replaced with the Management Deferred Compensation Plan, which does not have a guaranteed rate of return. Named executive officers who were participants in the 1996-1999 Deferred Compensation Plan for Key Management Employees continue to receive plan benefits with respect to amounts deferred prior to its discontinuance in 2000. The above market earnings under the Deferred Compensation Plan for Key Management Employees are included in this column for Mr. Johnson.

[6] Includes the following items: Company match contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; dividends paid under provisions of the Restricted Stock Award/Unit Plans and Management Deferred Compensation Plans; perquisites; and tax gross-ups related primarily to imputed income.

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

[8] Includes (i) the grant date fair value of the restricted stock units granted during 2009 under the 2007 Equity Incentive Plan, $1,213,150; and (ii) the grant date fair value of the performance shares granted during 2009 under the 2009 PSSP, $1,877,455. The maximum potential for the performance shares granted to Mr. Johnson in 2009 is $3,754,910 (200%), based on the March 17, 2009 closing stock price of $33.80.

[9] Includes changes in present value of the accrued benefit during 2009 for the following plans: Progress Energy Pension Plan: $65,737; the SERP: $1,068,674; and above market earnings on compensation deferred under the Deferred Compensation Plan for Key Management Employees of $10,037. Mr. Johnson's change in his year-over-year SERP benefit was relatively flat.

[10] Consists of (i) $14,700 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $43,582 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iii) $195,485 in Restricted Stock/Unit Dividends; (iv) $11,970 in tax gross-ups related to imputed income; and (v) $23,989 in perquisites consisting of the following: financial/estate/tax planning, $5,000; Internet and telecom access, $3,724; health club dues, $2,407; home security, $4,255; and spousal travel, $6,370. Other perquisites include luncheon club membership, executive physical and AD&D insurance.

[11] Includes (i) the grant date fair value of the restricted stock units granted during 2009 under the 2007 Equity Incentive Plan, $273,915; and (ii) the grant date fair value of the performance shares granted during 2009 under the 2009 PSSP, $382,075. The maximum potential for the performance shares granted to Mr. Mulhern in 2009 is $764,150 (200%), based on the March 17, 2009 closing stock price of $33.80.

[12] Includes changes in present value of the accrued benefit during 2009 for the following plans: Progress Energy Pension Plan: $46,636; and the SERP: $323,186. Mr. Mulhern's change in SERP decreased in 2009 primarily due to vesting of the total accumulated benefit that occurred in 2008.

[13] Consists of (i) $14,700 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $9,682 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iii) $5,276 in tax gross-ups related to imputed income; and (iv) $72,479 in Restricted Stock/Unit Dividends. The total value of the perquisites and personal benefits received by Mr. Mulhern was less than $10,000. Thus, these amounts are excluded from column (i).

[14] Includes (i) the grant date fair value of the restricted stock units granted during 2009 under the 2007 Equity Incentive Plan, $286,523; and (ii) the grant date fair value of the performance shares granted during 2009 under the 2009 PSSP, $441,597. The maximum potential for the performance shares granted to Mr. Lyash in 2009 is $883,194 (200%), based on the March 17, 2009 closing stock price of $33.80.

[15] Includes changes in present value of the accrued benefit during 2009 for the following plans: Progress Energy Pension Plan: $48,250; and the SERP: $196,119. Mr. Lyash's change in SERP decreased in 2009 primarily due to a lower FAS discount rate.

[16] Consists of (i) $14,700 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $12,256 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iii) $70,378 in Restricted Stock/Unit Dividends; (iv) $1,445 in tax gross-ups related to imputed income; and (v) $17,708 in perquisites including spousal use of Company aircraft, $14,669. Other perquisites include luncheon club membership, spousal

travel, home security, and Internet and telecom access. During 2009, the Company required Mr. Lyash to relocate from Florida to North Carolina in connection with his becoming the Company's Executive Vice President - Corporate Development. Mr. Lyash received standard Company relocation benefits totaling $53,005 that included travel expenses, the equivalent of one month's salary, temporary housing, shipment of household goods, and closing costs in connection with his purchase of a home in North Carolina. Mr. Lyash also received assistance with the sale of his home in Florida where the Company previously required Mr. Lyash to relocate in connection with his former role as President and Chief Executive Officer of Progress Florida, Inc. The Company purchased his Florida home at a price equal to the average of two independent appraisals after he was unable to sell the home within a 60-day marketing period. The Company agreed that if the purchase price of Mr. Lyash's Florida home, as determined by the average of the two independent appraisals, resulted in a loss on the sale of his prior home, the Company would pay Mr. Lyash the difference between the price he paid for the Florida home (excluding the cost of improvements made subsequent to such purchase) and the purchase price paid by the Company based on the independent appraisals. Because of the precipitous decline in the Florida housing market since Mr. Lyash's purchase of his Florida home, the agreed purchase price was significantly below Mr. Lyash's purchase price. SEC rules require that we include as fiscal year 2009 compensation this difference, which was $80,000, along with other transaction costs. In light of the fact that the relocation was required by the Company and because this make-whole amount paid to Mr. Lyash will be treated as income to him, we agreed to provide Mr. Lyash with a tax gross-up on amounts from this transaction that are considered taxable income. The tax gross-up was $42,569. In approving Mr. Lyash's relocation expenses, including the reimbursement of the loss incurred on his Florida home, the Committee required Mr. Lyash to agree to reimburse the Company for the relocation assistance in the event he voluntarily leaves the Company within three years of relocating to North Carolina.

[17] Includes (i) the grant date fair value of the restricted stock units granted during 2009 under the 2007 Equity Incentive Plan, $284,055; and (ii) the grant date fair value of the performance shares granted during 2009 under the 2009 PSSP, $436,628. The maximum potential for the performance shares granted to Mr. Yates in 2009 is $873,257 (200%), based on the March 17, 2009 closing stock price of $33.80.

[18] Includes changes in present value of the accrued benefit during 2009 for the following plans: Progress Energy Pension Plan: $33,106; and the SERP: $275,709. Mr. Yates' change in SERP decreased in 2009 primarily due to vesting of the total accumulated benefit that occurred in 2008.

[19] Consists of (i) $14,700 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $11,956 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iii) $70,986 in Restricted Stock/Unit Dividends; (iv) $4,026 in tax gross-ups related to imputed income; and (v) $17,764 in perquisites including financial/estate/tax planning, $10,000, and spousal use of Company aircraft, $4,920. Other perquisites include luncheon club membership, health club dues, home security, Internet and telecom access, executive physical and AD&D insurance.

[20] Includes (i) the grant date fair value of the restricted stock units granted during 2009 under the 2007 Equity Incentive Plan, $224,500; and (ii) the grant date fair value of the performance shares granted during 2009 under the 2009 PSSP, $313,833. The maximum potential for the performance shares granted to Ms. Sims in 2009 is $627,666 (200%), based on the March 17, 2009 closing stock price of $33.80.

[21] Includes changes in present value of the accrued benefit during 2009 for the following plans: Progress Energy Pension Plan: $30,117; and the SERP: $703,105. Ms. Sims became vested in the SERP on June 1, 2009 which attributed to her increase for the year. Ms. Sims' accumulated Restoration Plan benefit of $25,420 was forfeited upon her vesting in the SERP.

[22] Consists of (i) $14,700 in Company contributions under the Progress Energy 401(k) Savings & Stock Ownership Plan; (ii) $7,500 in deferred compensation credits pursuant to the terms of the Management Deferred Compensation Plan; (iii) $47,759 in Restricted Stock/Unit Dividends; (iv) $15,188 in tax gross-ups related to imputed income; and (v) $12,358 in stock purchase discounts for annual incentive deferrals pursuant to the MICP. The total value of the perquisites and personal benefits received by Ms. Sims was less than $10,000. Thus, these amounts are excluded from column (i).

GRANTS OF PLAN-BASED AWARDS

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1] Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards[2] Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units[3] (#) (i)	Grant Date Fair Value of Stock and Option Awards[4] ($) (j)
William D. Johnson, Chairman, President and Chief Executive Officer	MICP 3/5/10	$416,173	$832,346	$1,664,692					
	Restricted Stock Units 3/17/09							35,892	$1,213,150
	PSSP 3/17/09				27,773	55,546	111,092		$1,877,455
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	MICP 3/5/10	$113,914	$227,827	$455,654					
	Restricted Stock Units 3/17/09							8,104	$273,915
	PSSP 3/17/09				5,652	11,304	22,608		$382,075
Jeffrey J. Lyash, Executive Vice President - Corporate Development (formerly President and Chief Executive Officer, PEF)	MICP 3/5/10	$123,983	$247,965	$495,930					
	Restricted Stock Units 3/17/09							8,477	$286,523
	PSSP 3/17/09				6,533	13,065	26,130		$441,597
Lloyd M. Yates, President and Chief Executive Officer, PEC	MICP 3/5/10	$122,608	$245,215	$490,430					
	Restricted Stock Units 3/17/09							8,404	$284,055
	PSSP 3/17/09				6,459	12,918	25,836		$436,628
Paula J. Sims, Senior Vice President – Power Operations	MICP 3/5/10	$83,250	$166,500	$333,000					
	Restricted Stock Units 3/17/09							6,642	$224,500
	PSSP 3/17/09				4,643	9,285	18,570		$313,833

[1] The Management Incentive Compensation Plan is considered a non-equity incentive compensation plan. Award amounts are shown at threshold, target, and maximum levels. The target award is calculated using the 2009 eligible earnings times the executive's target percentage. See target percentage in table on page 30 of the CD&A. Threshold is calculated at 50% of target and maximum is calculated at 200% of target. Actual award amounts paid are reflected in the Summary of Compensation Table under the "Non-Equity Incentive Plan Compensation" column.

[2] Reflects the potential payouts in shares of the 2009 PSSP grants. The grant size was calculated by multiplying the executive's salary as of January 1, 2009, times his 2009 PSSP target and dividing by the December 31, 2008, closing stock price of $39.85. The Threshold column reflects the minimum payment level under our PSSP, which is 50% of the target amount shown in the Target column. The amount shown in the maximum column is 200% of the target amount.

[3] Reflects the number of restricted stock units granted during 2009 under the 2007 Equity Incentive Plan. The number of shares granted was determined by multiplying the executive's salary as of January 1, 2009, times his 2009 restricted stock target and dividing by the December 31, 2008, closing stock price of $39.85.

[4] Reflects the grant date fair value of the award based on the following assumptions: Market value of restricted stock granted on March 17, 2009, based on closing price of $33.80 per share, times the shares granted in column (i). Market value of PSSP granted on March 17, 2009, based on closing stock price on March 17, 2009, of $33.80 times target number of shares in column (g). The 2009 PSSP grant payout is expected to be 100% of target.

DISCUSSION OF SUMMARY COMPENSATION TABLE AND GRANTS OF PLAN-BASED AWARDS TABLE

EMPLOYMENT AGREEMENTS

Messrs. Johnson, Mulhern, Lyash and Yates and Ms. Sims entered into employment agreements with the Company or one of its subsidiaries, referred to collectively in this section as the "Company." Each of these agreements has an effective date of May 8, 2007. The employment agreements replaced the previous employment agreements in effect for each of these officers.

The employment agreements provide for base salary, annual incentives, perquisites and participation in the various executive compensation plans offered to our senior executives. The agreements expired on December 31, 2009. Thereafter, each agreement will be automatically extended by an additional year on January 1 of each year. We may elect not to extend an executive officer's agreement and must notify the officer of such an election at least 60 days prior to the automatic extension date. Each employment agreement contains restrictive covenants imposing non-competition obligations, restricting solicitation of employees and protecting our confidential information and trade secrets for specified periods if the applicable officer is terminated without cause or otherwise becomes eligible for the benefits under the agreement.

Except for the application of previously granted years of service credit to our post-employment health and welfare plans as discussed below, the employment agreements do not affect the compensation, benefits or incentive targets payable to the applicable officers:

With respect to Mr. Johnson, the Employment Agreement specifies that the years of service credit we previously granted to him for purposes of determining eligibility and benefits in the SERP will also be applicable for purposes of determining eligibility and benefits in our post-employment health and welfare benefit plans. Mr. Johnson was awarded seven years of deemed service toward the benefits and vesting requirements of the SERP. However, as of 2008, Mr. Johnson reached the maximum service accrual and therefore benefit augmentation for deemed service is $0. Three of those years also were deemed to have been in service on the Senior Management Committee for purposes of SERP eligibility.

Each Employment Agreement provides that if the applicable officer is terminated without cause or is constructively terminated (as defined in Paragraph 8(a)(i) of the agreement), then the officer will receive (i) severance equal to 2.99 times the officer's then-current base salary and (ii) reimbursement for the costs of continued coverage under certain of our health and welfare benefit plans for a period of up to 18 months.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards[1]					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable (b)	Number of Securities Underlying Unexercised Options (#) Unexercisable (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)[2]	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)[3]	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)[4]	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[4]
William D. Johnson, Chairman, President and Chief Executive Officer	0 0 0	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	82,135[5]	$3,368,356	152,673[6]	$6,261,120
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	0 0 7,000	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	26,776[7]	$1,098,084	29,966[8]	$1,228,906
Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, PEF)	0 0 0	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	29,232[9]	$1,198,804	38,528[10]	$1,580,033
Lloyd M. Yates, President and Chief Executive Officer, PEC	0 0 0	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	29,159[11]	$1,195,811	38,373[12]	$1,573,677
Paula J. Sims, Senior Vice President – Power Operations	0 0 0	—	—	$43.49 $41.97 $44.75	9/30/2011 9/30/2012 9/30/2013	20,617[13]	$845,503	28,305[14]	$1,160,778

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

[2] Consists of outstanding restricted stock grants and restricted stock units.

[3] Market value at December 31, 2009, was based on a December 31, 2009, closing price of $41.01 per share.

[4] The 2006 and 2007 2-year transitional grants vested on January 1, 2009; the 2007 grant vests on January 1, 2010; the 2008 grant vests on January 1, 2011; and the 2009 grant vests on January 1, 2012. Performance share value for the 2007 annual grant is expected to be at 125% of target while the 2008 annual grant and 2009 annual grant were expected to be 100% of target. The value in Column (j) is derived by multiplying the shares (rounded to the nearest whole share) times the December 31, 2009 closing stock price ($41.01). The difference between the calculated value and the noted value is attributable to fractional shares. See further discussion under "Performance Shares" in Part II of the CD&A.

[5] Restricted stock grants vest based on the following schedule: 5,533 shares on March 14, 2010; 5,067 shares on March 15, 2010; and 5,534 shares on March 14, 2011. Restricted stock unit grants vest based on the following schedule: 9,297 units on March 17, 2010; 9,297 units on March 17, 2011; 17,298 units on March 17, 2012; 7,650 units on March 18, 2010; 4,936 units on March 20, 2010; 7,651 units on March 18, 2011; 4,936 units on March 20, 2011; and 4,936 units on March 20, 2012.

[6] Includes performance shares granted on March 20, 2007, March 18, 2008, March 17, 2009, and accumulated dividends as of December 31, 2009. Outstanding performance share balances consist of the following: (i) 43,280 – 2007 annual grant; (ii) 51,018 – 2008 annual grant; and (iii) 58,375 – 2009 annual grant.

[7] Restricted stock grants vest based on the following schedule: 1,167 shares on March 14, 2010; 3,500 shares on March 21, 2010; and 1,167 shares on March 14, 2011. Restricted stock unit grants vest based on the following schedule: 1,868 units on March 17, 2010; 1,868 on March 17, 2011; 4,368 on March 17, 2012; 1,136 units on March 18, 2010; 8,189 units on March 20, 2010; 1,136 units on March 18, 2011; 1,189 units on March 20, 2011; and 1,188 units on March 20, 2012.

[8] Includes performance shares granted on March 20, 2007, March 18, 2008, March 17, 2009, and accumulated dividends as of December 31, 2009. Outstanding performance share balances consist of the following: (i) 10,479 – 2007 annual grant; (ii) 7,607 – 2008 annual grant; and (iii) 11,880 – 2009 annual grant.

[9] Restricted stock grants vest based on the following schedule: 1,367 shares on March 14, 2010; 1,100 shares on March 15, 2010; and 1,367 on March 14, 2011. Restricted stock unit grants vest based on the following schedule: 2,159 units on March 17, 2010; 1,597 on March 18, 2010; 10,576 units on March 20, 2010; 2,159 units on March 17, 2011; 1,597 units on March 18, 2011; 1,576 units on March 20, 2011; 4,159 units on March 17, 2012; and 1,575 units on March 20, 2012.

[10] Includes performance shares granted on March 20, 2007, March 18, 2008, March 17, 2009, and accumulated dividends as of December 31, 2009. Outstanding performance share balances consist of the following: (i) 14,010 – 2007 annual grant; (ii) 10,787 – 2008 annual grant; and (iii) 13,731 – 2009 annual grant.

[11] Restricted stock grants vest based on the following schedule: 1,367 shares on March 14, 2010; 1,100 shares on March 15, 2010; and 1,367 shares on March 14, 2011. Restricted stock unit grants vest based on the following schedule: 2,134 on March 17, 2010; 1,597 on March 18, 2010; 10,576 units on March 20, 2010; 2,135 on March 17, 2011; 1,597 units on March 18, 2011; 1,576 units on March 20, 2011; 4,135 on March 17, 2012; and 1,575 units on March 20, 2012.

[12] Includes performance shares granted on March 20, 2007, March 18, 2008, March 17, 2009, and accumulated dividends as of December 31, 2009. Outstanding performance share balances consist of the following: (i) 14,010 – 2007 annual grant; (ii) 10,787 – 2008 annual grant; and (iii) 13,576 – 2009 annual grant.

[13] Restricted stock grants vest based on the following schedule: 1,000 shares on April 1, 2011. Restricted stock units grants vest based on the following schedule: 1,547 units on March 17, 2010; 1,204 units on March 18, 2010; 8,189 units on March 20, 2010; 1,547 units on March 17, 2011; 1,205 units on March 18, 2011; 1,189 units on March 20, 2011; 3,548 units on March 17, 2011; and 1,188 units on March 20, 2012.

[14] Includes performance shares granted on March 20, 2007, March 18, 2008, March 17, 2009, and accumulated dividends as of December 31, 2009. Outstanding performance share balances consist of the following: (i) 10,479 – 2007 annual grant; (ii) 8,068 – 2008 annual grant; and (iii) 9,758 – 2009 annual grant.

OPTION EXERCISES AND STOCK VESTED

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting[1] (#) (d)	Value Realized on Vesting[1] ($) (e)
William D. Johnson, Chairman, President and Chief Executive Officer	—	—	55,597[2]	$2,049,258
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	—	—	18,077[3]	$656,906
Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, PEF)	—	—	15,727[4]	$589,337
Lloyd M. Yates, President and Chief Executive Officer, PEC	—	—	16,927[5]	$630,131
Paula J. Sims, Senior Vice President – Power Operations	—	—	9,180[6]	$358,539

[1] Reflects the number of restricted stock shares, restricted stock units, and performance shares that vested in 2009. Restricted stock units vested for named executive officers on March 18 at $33.80 per share, and performance shares vested on January 1, 2009 for the 2006 and 2007 2-year transitional grants at $39.85 per share. Restricted stock shares vested on the following days: (i) March 7 at $33.02 per share; (ii) March 14, 15, and 16 at $31.85 per share; and (iii) April 28 at $33.79 per share. The value realized is the sum of the vested shares for each vesting date times the vesting price.

[2] Includes 15,000 restricted stock awards consisting of the following: 5,533 on March 14; 5,067 on March 15; and 4,400 on March 16. Performance shares totaled 32,947. Restricted stock units totaled 7,650.

[3] Includes 8,966 restricted stock awards consisting of the following: 1,166 on March 14; and 7,800 on April 28. Performance shares totaled 7,976. Restricted stock units totaled 1,135.

[4] Includes 3,466 restricted stock awards consisting of the following: 1,366 on March 14; 1,100 on March 15; and 1,000 on March 16. Performance shares totaled 10,665. Restricted stock units totaled 1,596.

[5] Includes 4,666 restricted stock awards consisting of the following: 2,200 on March 7; 1,366 on March 14; and 1,100 on March 15. Performance shares totaled 10,665. Restricted stock units totaled 1,596.

[6] Performance shares totaled 7,976. Restricted stock units totaled 1,204. Ms. Sims did not have any restricted stock awards that vested during 2009.

PENSION BENEFITS TABLE

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit[1] ($) (d)	Payments During Last Fiscal Year ($) (e)
William D. Johnson, Chairman, President and Chief Executive Officer	Progress Energy Pension Plan	17.3	$448,578	$0
	Supplemental Senior Executive Retirement Plan	24.3[2]	$7,282,483[3]	$0
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	Progress Energy Pension Plan	13.8	$269,399	$0
	Supplemental Senior Executive Retirement Plan	13.8	$1,144,767[4]	$0
Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, PEF)	Progress Energy Pension Plan	16.6	$274,417	$0
	Supplemental Senior Executive Retirement Plan	16.6	$1,419,208[5]	$0
Lloyd M. Yates, President and Chief Executive Officer, PEC	Progress Energy Pension Plan	11.1	$157,608	$0
	Supplemental Senior Executive Retirement Plan	11.1	$1,065,706[6]	$0
Paula J. Sims, Senior Vice President – Power Operations	Progress Energy Pension Plan	10.6	$131,941	$0
	Restoration Retirement Plan	—	($25,420)[7]	$0
	Supplemental Senior Executive Retirement Plan	10.6	$703,105[8]	$0

[1] Actuarial present value factors as provided by our actuarial consultants, Buck Consultants, based on FAS mortality assumptions post-age 65 and FAS discount rates as of December 31, 2009, for computation of accumulated benefit under the Supplemental Senior Executive Retirement Plan and the Progress Energy Pension Plan was 6.10%. Additional details on the formulas for computing benefits under the Supplemental Senior Executive Retirement Plan and Progress Energy Pension Plan can be found under the headings "Supplemental Senior Executive Retirement Plan" and "Other Broad-Based Benefits," respectively, in the CD&A.

[2] Includes seven years of deemed service. However, as of 2008, Mr. Johnson reached the maximum service accrual and therefore benefit augmentation for deemed service is $0.

[3] Based on an estimated annual benefit payable at age 65 of $1,043,010.

[4] Based on an estimated annual benefit payable at age 65 of $233,894.

[5] Based on estimated annual benefit payable at age 65 of $326,421.

[6] Based on estimated annual benefit payable at age 65 of $231,022.

[7] Ms. Sims' Restoration Retirement Plan benefits were forfeited upon her vesting in the Senior Supplemental Retirement Plan on June 1, 2009.

[8] Based on estimated annual benefit payable at age 65 of $161,716.

NONQUALIFIED DEFERRED COMPENSATION

The table below shows the nonqualified deferred compensation for each of the named executive officers. Information regarding details of the deferred compensation plans currently in effect can be found under the heading "Deferred Compensation" in the CD&A on page 39 of this Proxy Statement. In addition, the Deferred Compensation Plan for Key Management Employees is discussed in footnote 5 to the "Summary Compensation Table."

Name and Position (a)	Executive Contributions in Last FY[1] ($) (b)	Registrant Contributions in Last FY[2] ($) (c)	Aggregate Earnings in Last FY[3] ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE[4] ($) (f)
William D. Johnson, Chairman, President and Chief Executive Officer	$0	$43,582	$76,353[5]	$0	$736,071[6]
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	$20,712	$9,682	$30,580	($32,861)[7]	$325,876[8]
Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, PEF)	$0	$12,256	$31,303	$0	$135,173[9]
Lloyd M. Yates, President and Chief Executive Officer, PEC	$0	$11,956	$60,701	$0	$499,804[10]
Paula J. Sims, Senior Vice President – Power Operations	$107,000	$19,858	$44,241	($14,115)[11]	$444,049[12]

[1] Reflects salary deferred under the Management Deferred Compensation Plan, which is reported as "Salary" in the Summary Compensation Table. For 2009, named executive officers deferred the following percentages of their base salary: (i) Mulhern – 5%; and (ii) Sims – 10%. In addition, Ms. Sims deferred 50% of her 2009 Management Incentive Compensation Plan (MICP) award.

[2] Reflects registrant contributions under the Management Deferred Compensation Plan, which is reported as "All Other Compensation" in the Summary Compensation Table.

[3] Includes aggregate earnings in the last fiscal year under the following nonqualified plans: Management Incentive Compensation Plan, Management Deferred Compensation Plan, Performance Share Sub-Plan, and Deferred Compensation Plan for Key Management Employees.

[4] Includes December 31, 2009 balances under the following deferred compensation plans: Management Incentive Compensation Plan, Performance Share Sub-Plan, Management Deferred Compensation Plan, and Deferred Compensation Plan for Key Management Employees.

[5] Includes above market earnings of $10,037 under the Deferred Compensation Plan for Key Management Employees, which is reported as "Change in Pension Value and Nonqualified Deferred Compensation Earnings" in the Summary Compensation Table.

[6] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $413,100; Management Incentive Compensation Plan: $69,090; and Deferred Compensation Plan for Key Management Employees: $253,881.

[7] Mr. Mulhern received distributions from his Management Incentive Deferred Compensation Plan: $23,077; Management Deferred Compensation Plan: $0; and Performance Share Sub-Plan: $9,784.

[8] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $71,311; Management Incentive Deferred Compensation Plan: $155,570; and Performance Share Sub-Plan: $98,995.

[9] Includes balance under the Management Deferred Compensation Plan: $135,173.

[10] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $134,519; Management Incentive Deferred Compensation Plan: $107,892; and Performance Share Sub-Plan: $257,393.

[11] Ms. Sims received a distribution from her Management Incentive Deferred Compensation Plan: $14,115.

[12] Includes balances under the following deferral plans: Management Deferred Compensation Plan: $296,625; Management Incentive Compensation Plan: $86,401; and Performance Share Sub-Plan: $61,023.

CASH COMPENSATION AND VALUE OF VESTING EQUITY TABLE

The following table shows the actual cash compensation and value of vesting equity received in 2009 by the named executive officers. The Committee believes that this table is important in order to distinguish between the actual cash and vested value received by each named executive officer as opposed to the compensation expense accruals and grant date fair value of equity awards as shown in the Summary Compensation Table.

Name and Position	Base Salary (a)[1]	Annual Incentive (paid in 2009) (b)[2]	Deferred Compensation under MDCP and MICP (c)[3]	Restricted Stock / Units Vesting (d)[4]	Performance Shares Vesting (e)[5]	Restricted Stock / Unit Dividends (f)[6]	Stock Options Vesting (g)[7]	Perquisite (h)[8]	Tax Gross-ups (i)[9]	Total
William D. Johnson, Chairman, Chief Executive Officer and President	$979,231	$929,000	$0	$736,320	$1,163,688	$195,485	$0	$23,989	$11,970	$4,039,683
Mark F. Mulhern, Senior Vice President and Chief Financial Officer	$414,231	$200,000	$20,712	$339,062	$281,712	$72,479	$0	$2,093	$5,276	$1,314,853
Jeffrey J. Lyash, Executive Vice President – Corporate Development (formerly President and Chief Executive Officer, PEF)	$450,846	$225,000	$0	$164,337	$376,688	$70,378	$0	$5,621	$44,015	$1,336,885
Lloyd M. Yates, President and Chief Executive Officer, PEC	$445,846	$210,000	$0	$205,131	$376,688	$70,986	$0	$13,726	$4,026	$1,326,403
Paula J. Sims, Senior Vice President – Power Operations	$370,000	$140,000	$107,000	$40,695	$281,712	$47,759	$0	$9,587	$15,188	$904,941

[1] Consists of the total 2009 base salary earnings prior to (i) employee contributions to the Progress Energy 401(k) Savings & Stock Ownership Plan and (ii) voluntary deferrals, if applicable, under the Management Deferred Compensation Plan (MDCP) shown in column (c).

[2] Awards given under the Management Incentive Compensation Plan (MICP) attributable to Plan Year 2008 and paid in 2009.

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

[4] Reflects the value of restricted stock and restricted stock units vesting in 2009. The value of the restricted stock was calculated using the opening stock price for Progress Energy Common Stock three days prior to the day vesting occurred. The value of the restricted stock units was calculated using the closing stock price for Progress Energy Common Stock on the business day prior to when vesting occurred.

[5] Reflects the value of performance shares vesting on January 1, 2009. The value of the 2007 2-year transitional performance share units was calculated using the closing stock price for Progress Energy Common Stock on the business day prior to when distribution occurred.

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

[7] Reflects the value of any stock options vesting in 2009. Since we ceased granting stock options under our Incentive Plans in 2004, all outstanding options had fully vested in 2009.

[8] Reflects the value of all perquisites provided during 2009. For a complete listing of the perquisites, see the "Executive Perquisites" section of the "Elements of Compensation" discussion of the CD&A on page 38 of this Proxy Statement. Perquisite details for each named executive officer are discussed in the Summary Compensation Table footnotes.

[9] Reflects the value of tax gross-up related to miscellaneous income items (Supplemental Senior Executive Retirement Plan (SERP) or Restoration and MDCP 401(k) make-up) provided during 2009. In addition, Mr. Lyash received an additional $42,569 in tax gross-up from the loss on the sale of his home as disclosed in the Summary Compensation Table footnotes.

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

	Voluntary Termination ($)	Early Retirement[1] ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$990,000[2]	$0	$0	$0	$2,960,100	$0	$5,657,500	$0
Annual Incentive[3]	$0	$950,000	$0	$0	$0	$841,500	$950,000
Long-term Incentives							
Performance Shares (PSSP)[4]							
2007 (performance period)	$0	$1,774,913	$0	$0	$0	$1,774,913	$1,774,913
2008 (performance period)	$0	$1,394,832	$0	$0	$0	$2,092,248	$1,394,832
2009 (performance period)	$0	$797,986	$0	$0	$0	$2,393,959	$797,986
Restricted Stock Units[5]							
2007 – 2010 (grant date vesting)	$0	$185,557	$0	$0	$0	$202,425	$202,425
2007 – 2011 (grant date vesting)	$0	$139,167	$0	$0	$0	$202,425	$202,425
2007 – 2012 (grant date vesting)	$0	$111,334	$0	$0	$0	$202,425	$202,425
2008 – 2010 (grant date vesting)	$0	$274,511	$0	$0	$0	$313,727	$313,727
2008 – 2011 (grant date vesting)	$0	$183,031	$0	$0	$0	$313,768	$313,768
2009 – 2010 (grant date vesting)	$0	$285,952	$0	$0	$0	$381,270	$0
2009 – 2011 (grant date vesting)	$0	$142,976	$0	$0	$0	$381,270	$0
2009 – 2012 (grant date vesting)	$0	$177,348	$0	$0	$0	$709,391	$0
Restricted Stock[6]							
Unvested and Accelerated	$0	$661,655	$0	$0	$0	$661,655	$661,655
Benefits and Perquisites							
Incremental Nonqualified Pension[7]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[8]	$736,071	$736,071	$0	$736,071	$736,071	$736,071	$736,071
Post-retirement Health Care[9]	$0	$0	$0	$23,022	$0	$45,140	$0
Executive AD&D Proceeds[10]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[11]	$0	$0	$0	$0	$0	$5,097,620	$0
TOTAL	**$736,071**	**$7,815,333**	**$0**	**$3,719,193**	**$736,071**	**$22,007,307**	**$8,050,227**

[1] Mr. Johnson became eligible for early retirement at age 55 in January 2009. Therefore, under the voluntary termination and involuntary not for cause termination scenarios, Mr. Johnson would be treated as having met the early retirement criteria under the Equity Incentive Plan and would be paid out under the early retirement provisions of that plan.

[2] There is no provision for payment of salary under voluntary termination, early retirement, for cause termination, death or disability. Mr. Johnson is not eligible for normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Mr. Johnson's employment agreement requires a severance equal to 2.99 times his then current base salary ($990,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals the sum of annual salary times three plus average MICP award for the three years prior times three (($990,000 + $895,833) x 3). Does not include impact of long-term disability. In the event of a long-term disability, Mr. Johnson would receive 60% of base salary during the period of his disability.

[3] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Johnson is not eligible for normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Johnson would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 85% times $990,000. In the event of early retirement, death or disability, Mr. Johnson would receive a pro-rata incentive award for the period worked during the year. For December 31, 2009, this is based on the full award. For 2009, Mr. Johnson's MICP award was $950,000.

[4] Unvested performance shares would be forfeited under for cause termination. Voluntary termination and involuntary not for cause termination are not applicable. See footnote 1. Mr. Johnson is not eligible for normal retirement. In the event of early retirement, Mr. Johnson would receive 43,280 performance shares from the 2007 grant; 34,012 performance shares from the 2008 grant; and 18,458 performance shares from the 2009 grant. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the applicable performance factor. As of December 31, 2009, the performance factor is 100%. In the event of death or disability, the 2007 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2008 and 2009 performance grants, a pro-rata payment would be made based upon time in the plan.

[5] Unvested restricted stock units (RSU) would be forfeited under for cause termination. Voluntary termination and involuntary not for cause termination are not applicable. See footnote 1. In the event of early retirement, Mr. Johnson would receive a pro-rata percentage of the unvested units, based upon the number of full months elapsed between the grant date and the date of early retirement. Mr. Johnson would vest the following on a pro-rata basis: 10,633 restricted stock units granted on March 20, 2007; 11,157 restricted stock units granted on March 18, 2008; and 14,784 units granted on March 17, 2009. Mr. Johnson is not eligible for normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock units would vest immediately. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Johnson would immediately vest 14,808 restricted stock units granted on March 20, 2007; 15,301 restricted stock units granted on March 18, 2008; and would forfeit 35,892 restricted stock units granted on March 17, 2009.

[6] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. In the event of early retirement, all 16,134 outstanding restricted stock shares may vest at the Committee's discretion. Mr. Johnson is not eligible for normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock shares would vest immediately. For a detailed description of outstanding restricted stock shares, see "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Johnson's restricted stock grant dates are beyond the one-year threshold; therefore, all 16,134 restricted stock shares would vest immediately.

[7] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Johnson was vested under the SERP as of December 31, 2009, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC). For a detailed description of the accumulated SERP benefit and estimated annual benefit payable at age 65, see "Pension Benefits Table." In the event of early retirement, Mr. Johnson would receive a 2.5% decrease in his accrued SERP benefit for each year that he is younger than age 65.

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

[9] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. In the event of early retirement, Mr. Johnson would receive no additional benefits above what all full-time, non bargaining employees would receive. Mr. Johnson is not eligible for normal retirement. Under involuntary not for cause termination, Mr. Johnson would be reimbursed for 18 months of COBRA premiums at $1,278.98 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Company-paid medical, dental and vision coverage in the same plan Mr. Johnson was participating in prior to termination for 36 months at $1,253.90 per month.

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

[11] Upon a change in control, the Management Change-in-Control Plan provides for the Company to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Johnson. Under IRC Section 280G, Mr. Johnson would be subject to excise tax on $9,400,700 of excess parachute payments above his base amount. Those excess parachute payments result in $1,880,140 of excise taxes, $3,144,621 of tax gross-ups, and $72,859 of employer Medicare tax related to the excise tax payment.

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

	Voluntary Termination ($)	Early Retirement ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$425,000[1]	$0	$0	$0	$1,270,750	$0	$1,317,500	$0
Annual Incentive[2]	$0	$0	$0	$0	$0	$233,750	$225,000
Long-term Incentives							
Performance Shares (PSSP)[3]							
2007 (performance period)	$0	$0	$0	$0	$0	$429,734	$429,734
2008 (performance period)	$0	$0	$0	$0	$0	$311,963	$198,522
2009 (performance period)	$0	$0	$0	$0	$0	$487,199	$132,872
Restricted Stock Units[4]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$335,831	$335,831
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$48,761	$48,761
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$48,720	$48,720
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$46,587	$46,587
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$46,587	$46,587
2009 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$76,607	$0
2009 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$76,607	$0
2009 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$179,132	$0
Restricted Stock[5]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$239,252	$239,252
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$325,876	$0	$0	$325,876	$325,876	$325,876	$325,876
Post-retirement Health Care[8]	$0	$0	$0	$15,249	$0	$19,934	$0
Executive AD&D Proceeds[9]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[10]	$0	$0	$0	$0	$0	$1,459,661	$0
TOTAL	**$325,876**	**$0**	**$0**	**$1,611,875**	**$325,876**	**$5,683,701**	**$2,577,742**

[1] There is no provision for payment of salary under voluntary termination, for cause termination, death or disability. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Mr. Mulhern's employment agreement requires a severance equal to 2.99 times his then current base salary ($425,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals the sum of annual salary times two plus annual target MICP award times two (($425,000 + $233,750) x 2). Does not include impact of long-term disability. In the event of a long-term disability, Mr. Mulhern would receive 60% of base salary during the period of his disability.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Mulhern would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $425,000. In the event of death or disability, Mr. Mulhern would receive a pro-rata incentive award for the period worked during the year. For December 31, 2009, this is based on the full award. For 2009, Mr. Mulhern's MICP award was $225,000.

[3] Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the applicable performance factor. As of December 31, 2009, the performance factor is 100%. In the event of death or disability, the 2007 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2008 and 2009 performance grants, a pro-rata payment would be made based upon time in the plan.

[4] Unvested restricted stock units (RSU) would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock units would vest immediately. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Mulhern would immediately vest 10,566 restricted stock units granted on March 20, 2007; 2,272 restricted stock units granted on March 18, 2008; and would forfeit 8,404 restricted stock units granted on March 17, 2009.

[5] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Mulhern is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock shares would vest immediately. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Mulhern's restricted stock grant dates are beyond the one-year threshold; therefore, all 5,834 restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Mulhern was vested under the SERP as of December 31, 2009, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

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

[8] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Mr. Mulhern is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. Mulhern would be reimbursed for 18 months of COBRA premiums at $847.18 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Company-paid medical, dental and vision coverage in the same plan Mr. Mulhern was participating in prior to termination for 24 months at $830.57 per month.

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

[10] Upon a change in control, the Management Change-in-Control Plan provides for the Company to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Mulhern. Under IRC Section 280G, Mr. Mulhern would be subject to excise tax on $2,691,811 of excess parachute payments above his base amount. Those excess parachute payments result in $538,362 of excise taxes, $900,436 of tax gross-ups, and $20,863 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Jeffrey J. Lyash, Executive Vice President – Corporate Development

	Voluntary Termination ($)	Early Retirement ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$453,000[1]	$0	$0	$0	$1,354,470	$0	$2,139,000	$0
Annual Incentive[2]	$0	$0	$0	$0	$0	$249,150	$235,000
Long-term Incentives							
Performance Shares (PSSP)[3]							
2007 (performance period)	$0	$0	$0	$0	$0	$574,550	$574,550
2008 (performance period)	$0	$0	$0	$0	$0	$442,375	$281,511
2009 (performance period)	$0	$0	$0	$0	$0	$563,108	$153,575
Restricted Stock Units[4]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$433,722	$433,722
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$64,632	$64,632
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$64,591	$64,591
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$65,493	$65,493
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$65,493	$65,493
2009 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$88,541	$0
2009 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$88,541	$0
2009 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$170,561	$0
Restricted Stock[5]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$157,232	$157,232
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$135,173	$0	$0	$135,173	$135,173	$135,173	$135,173
Post-retirement Health Care[8]	$0	$0	$0	$16,221	$0	$31,807	$0
Executive AD&D Proceeds[9]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[10]	$0	$0	$0	$0	$0	$1,620,699	$0
TOTAL	**$135,173**	**$0**	**$0**	**$1,505,864**	**$135,173**	**$6,954,668**	**$2,730,972**

[1] There is no provision for payment of salary under voluntary termination, for cause termination, death or disability. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Mr. Lyash's employment agreement requires a severance equal to 2.99 times his then current base salary ($453,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals the sum of annual salary times three plus average MICP award for the three years prior times three (($453,000 + $260,000) x 3). Does not include impact of long-term disability. In the event of a long-term disability, Mr. Lyash would receive 60% of base salary during the period of his disability.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Lyash would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $453,000. In the event of death or disability, Mr. Lyash would receive a pro-rata incentive award for the period worked during the year. For December 31, 2009, this is based on the full award. For 2009, Mr. Lyash's MICP award was $235,000.

[3] Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the applicable performance factor. As of December 31, 2009, the performance factor is 100%. In the event of death or disability, the 2007 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2008 and 2009 performance grants, a pro-rata payment would be made based upon time in the plan.

[4] Unvested restricted stock units (RSU) would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock units would vest immediately. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Lyash would immediately vest 13,727 restricted stock units granted on March 20, 2007; 3,194 restricted stock units granted on March 18, 2008; and would forfeit 8,477 restricted stock units granted on March 17, 2009.

[5] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Lyash is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock shares would vest immediately. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Lyash's restricted stock grant dates are beyond the one-year threshold; therefore, all 3,834 restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Lyash was vested under the SERP as of December 31, 2009, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

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

[8] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Mr. Lyash is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. Lyash would be reimbursed for 18 months of COBRA premiums at $901.19 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Company-paid medical, dental and vision coverage in the same plan Mr. Lyash was participating in prior to termination for 36 months at $883.52 per month.

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

[10] Upon a change in control, the Management Change-in-Control Plan provides for the Company to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Lyash. Under IRC Section 280G, Mr. Lyash would be subject to excise tax on $2,988,788 of excess parachute payments above his base amount. Those excess parachute payments result in $597,758 of excise taxes, $999,777 of tax gross-ups, and $23,164 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Lloyd M. Yates, President and Chief Executive Officer, PEC

	Voluntary Termination ($)	Early Retirement ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$448,000[1]	$0	$0	$0	$1,339,520	$0	$2,083,200	$0
Annual Incentive[2]	$0	$0	$0	$0	$0	$246,400	$235,000
Long-term Incentives							
Performance Shares (PSSP)[3]							
2007 (performance period)	$0	$0	$0	$0	$0	$574,550	$574,550
2008 (performance period)	$0	$0	$0	$0	$0	$442,375	$281,511
2009 (performance period)	$0	$0	$0	$0	$0	$556,752	$151,841
Restricted Stock Units[4]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$433,722	$433,722
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$64,632	$64,632
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$64,591	$64,591
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$65,493	$65,493
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$65,493	$65,493
2009 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$87,515	$0
2009 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$87,556	$0
2009 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$169,576	$0
Restricted Stock[5]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$157,232	$157,232
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$499,804	$0	$0	$499,804	$499,804	$499,804	$499,804
Post-retirement Health Care[8]	$0	$0	$0	$23,022	$0	$45,140	$0
Executive AD&D Proceeds[9]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[10]	$0	$0	$0	$0	$0	$1,621,931	$0
TOTAL	**$499,804**	**$0**	**$0**	**$1,862,346**	**$499,804**	**$7,265,962**	**$3,093,869**

[1] There is no provision for payment of salary under voluntary termination, for cause termination, death or disability. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Mr. Yates' employment agreement requires a severance equal to 2.99 times his then current base salary ($448,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals the sum of annual salary times three plus annual target MICP award times three (($448,000 + $246,400) x 3). Does not include impact of long-term disability. In the event of a long-term disability, Mr. Yates would receive 60% of base salary during the period of his disability.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Mr. Yates would receive 100% of his target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 55% times $448,000. In the event of death or disability, Mr. Yates would receive a pro-rata incentive award for the period worked during the year. For December 31, 2009 this is based on the full award. For 2009, Mr. Yates' MICP award was $235,000.

[3] Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the applicable performance factor. As of December 31, 2009, the performance factor is 100%. In the event of death or disability, the 2007 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2008 and 2009 performance grants, a pro-rata payment would be made based upon time in the plan.

[4] Unvested restricted stock units (RSU) would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock units would vest immediately. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Mr. Yates would immediately vest 13,727 restricted stock units granted on March 20, 2007; 3,194 restricted stock units granted on March 18, 2008; and would forfeit 8,404 restricted stock units granted on March 17, 2009.

[5] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Mr. Yates is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock shares would vest immediately. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Mr. Yates' restricted stock grant dates are beyond the one-year threshold; therefore, all 3,834 restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Mr. Yates was vested under the SERP as of December 31, 2009, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

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

[8] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Mr. Yates is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Mr. Yates would be reimbursed for 18 months of COBRA premiums at $1,278.98 per month as provided in his employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Company-paid medical, dental and vision coverage in the same plan Mr. Yates was participating in prior to termination for 36 months at $1,253.90 per month.

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

[10] Upon a change in control, the Management Change-in-Control Plan provides for the Company to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Mr. Yates. Under IRC Section 280G, Mr. Yates would be subject to excise tax on $2,991,059 of excess parachute payments above his base amount. Those excess parachute payments result in $598,212 of excise taxes, $1,000,537 of tax gross-ups, and $23,182 of employer Medicare tax related to the excise tax payment.

POTENTIAL PAYMENTS UPON TERMINATION
Paula J. Sims, Senior Vice President – Power Operations

	Voluntary Termination ($)	Early Retirement ($)	Normal Retirement ($)	Involuntary Not for Cause Termination ($)	For Cause Termination ($)	Involuntary or Good Reason Termination (CIC) ($)	Death or Disability ($)
Compensation							
Base Salary—$370,000[1]	$0	$0	$0	$1,106,300	$0	$1,073,000	$0
Annual Incentive[2]	$0	$0	$0	$0	$0	$166,500	$160,000
Long-term Incentives							
Performance Shares (PSSP)[3]							
2007 (performance period)	$0	$0	$0	$0	$0	$429,734	$429,734
2008 (performance period)	$0	$0	$0	$0	$0	$330,869	$210,553
2009 (performance period)	$0	$0	$0	$0	$0	$400,176	$109,139
Restricted Stock Units[4]							
2007 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$335,831	$335,831
2007 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$48,761	$48,761
2007 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$48,720	$48,720
2008 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$49,376	$49,376
2008 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$49,417	$49,417
2009 – 2010 (grant date vesting)	$0	$0	$0	$0	$0	$63,442	$0
2009 – 2011 (grant date vesting)	$0	$0	$0	$0	$0	$63,442	$0
2009 – 2012 (grant date vesting)	$0	$0	$0	$0	$0	$145,503	$0
Restricted Stock[5]							
Unvested and Accelerated	$0	$0	$0	$0	$0	$41,010	$41,010
Benefits and Perquisites							
Incremental Nonqualified Pension[6]	$0	$0	$0	$0	$0	$0	$0
Deferred Compensation[7]	$414,523	$0	$0	$414,523	$414,523	$444,049	$444,049
Post-retirement Health Care[8]	$0	$0	$0	$5,344	$0	$6,985	$0
Executive AD&D Proceeds[9]	$0	$0	$0	$0	$0	$0	$500,000
280G Tax Gross-up[10]	$0	$0	$0	$0	$0	$1,194,126	$0
TOTAL	**$414,523**	**$0**	**$0**	**$1,526,167**	**$414,523**	**$4,890,941**	**$2,426,590**

[1] There is no provision for payment of salary under voluntary termination, for cause termination, death or disability. Ms. Sims is not eligible for early retirement or normal retirement. In the event of involuntary not for cause termination, salary continuation provision per Ms. Sims' employment agreement requires a severance equal to 2.99 times her then current base salary ($370,000) payable in equal installments over a period of 2.99 years. In the event of involuntary or good reason termination (CIC), the maximum benefit allowed under the cash payment provision of the Management Change-in-Control Plan equals the sum of annual salary times two plus target MICP award times two (($370,000 + $166,500) x 2). Does not include impact of long-term disability. In the event of a long-term disability, Ms. Sims would receive 60% of base salary during the period of her disability.

[2] There is no provision for payment of annual incentive under voluntary termination, involuntary not for cause termination, or for cause termination. Ms. Sims is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), Ms. Sims would receive 100% of her target award under the Annual Cash Incentive Compensation Plan provisions of the Management Change-in-Control Plan, calculated as 45% times $370,000. In the event of death or disability, Ms. Sims would receive a pro-rata incentive award for the period worked during the year. For December 31, 2009, this is based on the full award. For 2009, Ms. Sims' MICP award was $160,000.

[3] Unvested performance shares would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Ms. Sims is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), unvested performance shares vest as of the date of Management Change-in-Control and payment is made based upon the applicable performance factor. As of December 31, 2009, the performance factor is 100%. In the event of death or disability, the 2007 performance shares would vest 100% and be paid in an amount using performance factors determined at the time of the event. For the 2008 and 2009 performance grants, a pro-rata payment would be made based upon time in the plan.

[4] Unvested restricted stock units (RSU) would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Ms. Sims is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock units would vest immediately. For a detailed description of outstanding restricted stock units, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock units that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. Ms. Sims would immediately vest 10,566 restricted stock units granted on March 20, 2007; 2,409 restricted stock units granted on March 18, 2008; and would forfeit 6,642 restricted stock units granted on March 17, 2009.

[5] Unvested restricted stock would be forfeited under voluntary termination, involuntary not for cause termination, or for cause termination. Ms. Sims is not eligible for early retirement or normal retirement. In the event of involuntary or good reason termination (CIC), all outstanding restricted stock shares would vest immediately. For a detailed description of outstanding restricted stock shares, see the "Outstanding Equity Awards at Fiscal Year-End Table." Upon death or disability, all outstanding restricted stock shares that are more than one year past their grant date would vest immediately. Shares that are less than one year past their grant date would be forfeited. All of Ms. Sims' restricted stock grant dates are beyond the one-year threshold; therefore, all 1,000 restricted stock shares would vest immediately.

[6] No accelerated vesting or incremental nonqualified pension benefit applies under any of these scenarios. Ms. Sims was vested under the SERP as of December 31, 2009, so there is no incremental value due to accelerated vesting under involuntary or good reason termination (CIC).

[7] All outstanding deferred compensation balances will be paid immediately following termination, subject to IRC Section 409(a) regulations, under voluntary termination, involuntary not for cause termination, for cause termination, involuntary or good reason termination (CIC), death and disability. Ms. Sims is not eligible for early retirement or normal retirement. Unvested MICP deferral premiums would be forfeited. Ms. Sims would forfeit $29,526 of unvested deferred MICP premiums.

[8] No post-retirement health care benefits apply under voluntary termination, for cause termination, death or disability. Ms. Sims is not eligible for early retirement or normal retirement. Under involuntary not for cause termination, Ms. Sims would be reimbursed for 18 months of COBRA premiums at $296.88 per month as provided in her employment agreement. In the event of involuntary or good reason termination (CIC), the Management Change-in-Control Plan provides for Company-paid medical, dental and vision coverage in the same plan Ms. Sims was participating in prior to termination for 24 months at $291.06 per month.

[9] Ms. Sims would be eligible to receive $500,000 proceeds from the executive AD&D policy.

[10] Upon a change in control, the Management Change-in-Control Plan provides for the Company to pay all excise taxes under IRC Section 280G plus applicable gross-up amounts for Ms. Sims. Under IRC Section 280G, Ms. Sims would be subject to excise tax on $2,202,132 of excess parachute payments above her base amount. Those excess parachute payments result in $440,426 of excise taxes, $736,633 of tax gross-ups, and $17,067 of employer Medicare tax related to the excise tax payment.

DIRECTOR COMPENSATION

The following includes the required table and related narrative detailing the compensation each director received for his or her services in 2009.

Name (a)	Fees Earned or Paid in Cash[1] ($) (b)	Stock Awards[2] ($) (c)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (f)	All Other Compensation[3] ($) (g)	Total ($) (h)
John D. Baker II	$28,433	$0	—	—	—	$2,186	$30,619
James E. Bostic, Jr.	$93,500	$60,000	—	—	—	$77,502	$231,002
David L. Burner (Retired May 13, 2009)	$51,750	$60,000	—	—	—	$15,640	$127,390
Harris E. DeLoach, Jr.	$103,500	$60,000	—	—	—	$51,844	$215,344
James B. Hyler, Jr.	$95,000	$60,000	—	—	—	$8,899	$163,899
Robert W. Jones	$100,654	$60,000	—	—	—	$35,715	$196,369
W. Steven Jones	$93,500	$60,000	—	—	—	$65,622	$219,122
E. Marie McKee	$107,000	$60,000	—	—	—	$148,522	$315,522
John H. Mullin, III	$108,500	$60,000	—	—	—	$112,871	$281,371
Charles W. Pryor, Jr.	$96,500	$60,000	—	—	—	$18,475	$174,975
Carlos A. Saladrigas	$93,500	$60,000	—	—	—	$58,558	$212,058
Theresa M. Stone	$107,000	$60,000	—	—	—	$57,114	$224,114
Alfred C. Tollison, Jr.	$101,500	$60,000	—	—	—	$50,966	$212,466

[1] Reflects the annual retainer plus any Board or Committee fees earned in 2009. Amounts may have been paid in cash or deferred into the Non-Employee Director Deferred Compensation Plan.

[2] Reflects the grant date fair value of awards granted under the Non-Employee Director Stock Unit Plan in 2009. The assumptions made in the valuation of awards granted pursuant to the Non-Employee Director Stock Unit Plan are not addressed in our consolidated financial statements, footnotes to our consolidated financial statements or in Management's Discussion and Analysis because the Director Plan is immaterial to our consolidated financial statements. As a liability plan under FASB ASC Topic 718, the fair value of the Director Plan is re-measured at each financial statement date. The grant date fair value for each stock unit granted to each director on January 2, 2009 was $40.65. The numbers of stock units outstanding in the Non-Employee Director Stock Unit Plan as of December 31, 2009 for each Director listed above are shown in the table in footnote 3 below.

[3] Includes the following items: The dollar value of dividend reinvestments and unit appreciation/depreciation accrued under the Non-Employee Director Stock Unit Plan; dividend reinvestments and unit appreciation/depreciation accrued under the Non-Employee Director Deferred Compensation Plan; tax gross-ups; and matching contributions made to eligible nonprofit organizations and to accredited colleges and universities under the Company's now suspended Matching Gifts Program as follows: James E. Bostic, Jr.–$5,500; W. Steven Jones–$2,300; E. Marie McKee–$1,071; and Charles W. Pryor, Jr.–$1,000. The dollar values of dividend reinvestments and unit appreciation for each Director listed above are in the table below. The total value of the perquisites and personal benefits received by each director was less than $10,000. Thus, those amounts are excluded from this column. The numbers of stock units outstanding in the Non-Employee Director Deferred Compensation Plan as of December 3, 2009 for each Director listed above are in the table below.

	Non-Employee Director Stock Unit Plan		Non-Employee Director Deferred Compensation Plan	
Name	Stock Units Outstanding as of Dec. 31, 2009 (see footnote 2 above)	Dividend Reinvestments and Unit Appreciation/ Depreciation in column (g) (see footnote 3 above)	Stock Units Outstanding as of Dec. 31, 2009 (see footnote 3 above)	Dividend Reinvestments and Unit Appreciation/ Depreciation in column (g) (see footnote 3 above)
John D. Baker II	0	$0	747	$2,186
James E. Bostic, Jr.	8,396	$29,764	11,260	$42,238
David L. Burner (Retired May 13, 2009)	0	($39,745)	14,682	$54,647
Harris E. DeLoach, Jr.	4,430	$15,147	9,506	$36,697
James B. Hyler, Jr.	1,576	$4,628	1,028	$4,272
Robert W. Jones	3,001	$9,881	6,548	$25,835
W. Steven Jones	5,939	$20,709	11,155	$42,613
E. Marie McKee	11,211	$40,141	28,649	$107,309
John H. Mullin, III	11,700	$41,944	19,113	$70,927
Charles W. Pryor, Jr.	3,001	$9,881	1,930	$7,594
Carlos A. Saladrigas	9,376	$33,378	6,701	$25,181
Theresa M. Stone	5,939	$20,709	9,747	$36,405
Alfred C. Tollison, Jr.	4,430	$15,147	9,131	$35,283

DISCUSSION OF DIRECTOR COMPENSATION TABLE

RETAINER AND MEETING FEES

During 2009, Directors who were not employees of the Company received an annual retainer of $80,000, of which $30,000 was automatically deferred under the Non-Employee Director Deferred Compensation Plan (see below). The Lead Director/Chair of the following Board Committees received an additional retainer of $15,000: Audit and Corporate Performance Committee; Governance Committee; and Organization and Compensation Committee. The Chair of each of the following standing Board Committees received an additional retainer of $10,000: Finance Committee and Operations and Nuclear Oversight Committee. The nonchair members of the following standing Board Committees received an additional retainer of $7,500: Audit and Corporate Performance Committee and the Organization and Compensation Committee. The nonchair members of the following standing Board Committees received an additional retainer of $6,000: Governance Committee; Finance Committee; and Operations and Nuclear Oversight Committee. The Nuclear Oversight Director received an additional retainer of $8,000. The Chair of the Nuclear Project Oversight Committee receives an attendance fee of $2,000 per meeting held by that Committee. Additionally, each member of the Nuclear Project Oversight Committee receives an attendance fee of $1,500 per meeting held by that Committee. Directors who are not employees of the Company received a fee of $1,500 per meeting, paid with the next quarterly retainer, for noncustomary meetings or reviews of the Company's operations that are approved by the Governance Committee. Directors who are employees of our Company do not receive an annual retainer or attendance fees. All Directors are reimbursed for expenses incidental to their service as Directors. Committee positions held by the Directors are discussed in the "Board Committees" section of this Proxy Statement.

The Non-Employee Director Stock Unit Plan provides that each Director will receive an annual grant of stock units that is equivalent to $60,000.

NON-EMPLOYEE DIRECTOR DEFERRED COMPENSATION PLAN

In addition to $30,000 from the annual retainer that is automatically deferred, outside Directors may elect to defer any portion of the remainder of their annual retainer and Board attendance fees until after the termination of their service on the Board under the Non-Employee Director Deferred Compensation Plan. Any deferred fees are deemed to be invested in a number of units of Common Stock of the Company, but participating Directors receive no equity interest or voting rights in any shares of the Common Stock. The number of units credited to the account of a participating Director is equal to the dollar amount of the deferred fees divided by the average of the high and low selling prices (i.e., market value) of the Common Stock on the day the deferred fees would otherwise be payable to the participating Director. The number of units in each account is adjusted from time to time to reflect the payment of dividends on the number of shares of Common Stock represented by the units. Unless otherwise agreed to by the participant and the Board, when the participant ceases to be a member of the Board of Directors, he or she will receive cash equal to the market value of a share of the Company's Common Stock on the date of payment multiplied by the number of units credited to the participant's account.

NON-EMPLOYEE DIRECTOR STOCK UNIT PLAN

Effective January 1, 1998, we established the Non-Employee Director Stock Unit Plan ("Stock Unit Plan"). The Stock Unit Plan provides for an annual grant of stock units equivalent to $60,000 to each non-employee Director. Each unit is equal in economic value to one share of the Company's Common Stock, but does not represent an equity interest or entitle its holder to vote. The number of units is adjusted from time to time to reflect the payment of dividends with respect to the Common Stock of the Company. Benefits under the Stock Unit Plan vest after a participant has been a member of the Board for five years and are payable solely in cash. Effective January 1, 2007, a Director shall be fully vested at all times in the stock units credited to his or her account.

OTHER COMPENSATION

Directors are eligible to receive certain perquisites, including tickets to various cultural arts and sporting events, which are *de minimis* in value. Each retiring Director also receives a gift valued at approximately $1,500 in appreciation for his/her service on the Board.

Additionally, in 2009, directors were eligible to receive a 50 percent match from the Company for contributions made in 2008 to eligible nonprofit organizations and to all accredited colleges and universities. The Company's Matching Gifts Program was suspended as of January 1, 2009.

We charge Directors with imputed income in connection with (i) their travel on Company aircraft for non-Company related purposes and (ii) their spouses' travel on Company aircraft. When spousal travel is at our invitation, we will gross up the Directors for taxes incurred in connection with the imputed income related to the travel.

EQUITY COMPENSATION PLAN INFORMATION
as of December 31, 2009

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	4,414,788	$42.64	6,436,623
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	4,414,788	$42.64	6,436,623

Column (a) includes stock options outstanding, outstanding performance units assuming maximum payout potential, and outstanding restricted stock units.

Column (b) includes only the weighted-average exercise price of outstanding options.

Column (c) includes reduction for unissued, outstanding performance units assuming maximum payout potential and unissued, outstanding restricted stock units, and issued restricted stock.

REPORT OF THE AUDIT AND CORPORATE PERFORMANCE COMMITTEE

The Audit and Corporate Performance Committee of the Company's Board of Directors (the "Audit Committee") has reviewed and discussed the audited financial statements of the Company for the fiscal year ended December 31, 2009, with the Company's management and with Deloitte & Touche LLP, the Company's independent registered public accounting firm. The Audit Committee discussed with Deloitte & Touche LLP the matters required to be discussed by Statement on Auditing Standards No. 114, as amended (AICPA, Professional Standards, Vol. 1 AU Section 380) as adopted by the Public Company Accounting Oversight Board in Rule 3200T, by the SEC's Regulation S-X, Rule 2-07, and by the NYSE's Corporate Governance Rules, as may be modified, amended or supplemented.

The Audit Committee has received the written disclosures and the letter from Deloitte & Touche LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant's communication with the Audit Committee concerning independence and has discussed with Deloitte & Touche LLP its independence.

Based upon the review and discussions noted above, the Audit Committee recommended to the Board of Directors that the Company's audited financial statements be included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2009, for filing with the SEC.

Audit and Corporate Performance Committee

Theresa M. Stone, Chair
James E. Bostic, Jr.
W. Steven Jones
Melquiades R. "Mel" Martinez*
Charles W. Pryor, Jr.
Carlos A. Saladrigas
Alfred C. Tollison, Jr.

* Mr. Martinez was elected to the Board effective March 1, 2010, and thus did not participate in the reviews and discussions described in the foregoing Report of the Audit Committee.

Unless specifically stated otherwise in any of the Company's filings under the Securities Act of 1933 or the Securities Exchange Act of 1934, the foregoing Report of the Audit Committee shall not be incorporated by reference into any such filings and shall not otherwise be deemed filed under such Acts.

DISCLOSURE OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM'S FEES

The Audit Committee has actively monitored all services provided by its independent registered public accounting firm, *Deloitte & Touche LLP*, the member firms of Deloitte & Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte") and the relationship between audit and non-audit services provided by Deloitte. We have adopted policies and procedures for pre-approving all audit and permissible non-audit services rendered by Deloitte, and the fees billed for those services. Our Controller (the "Controller") is responsible to the Audit Committee for enforcement of this procedure, and for reporting noncompliance. Pursuant to the pre-approval policy, the Audit Committee specifically pre-approved the use of Deloitte for audit, audit-related and tax services.

The pre-approval policy requires management to obtain specific pre-approval from the Audit Committee for the use of Deloitte for any permissible non-audit services, which generally are limited to tax services, including tax compliance, tax planning, and tax advice services such as return review and consultation and assistance. Other types of permissible non-audit services will not be considered for approval except in limited instances, which could include circumstances in which proposed services provide significant economic or other benefits to us. In determining whether to approve these services, the Audit Committee will assess whether these services adversely impair the independence of Deloitte. Any permissible non-audit services provided during a fiscal year that (i) do not aggregate more than 5 percent of the total fees paid to Deloitte for all services rendered during that fiscal year and (ii) were not recognized as non-audit services at the time of the engagement must be brought to the attention of the Controller for prompt submission to the Audit Committee for approval. These *de minimis* non-audit services must be approved by the Audit Committee or its designated representative before the completion of the services. Non-audit services that are specifically prohibited under the Sarbanes-Oxley Act Section 404, SEC rules, and Public Company Accounting Oversight Board ("PCAOB") rules are also specifically prohibited under the policy.

Prior to approval of permissible tax services by the Audit Committee, the policy requires Deloitte to (1) describe in writing to the Audit Committee (a) the scope of the service, the fee structure for the engagement and any side letter or other amendment to the engagement letter or any other agreement between the Company and Deloitte relating to the service and (b) any compensation arrangement or other agreement, such as a referral agreement, a referral fee or fee-sharing arrangement, between Deloitte and any person (other than the Company) with respect to the promoting, marketing or recommending of a transaction covered by the service; and (2) discuss with the Audit Committee the potential effects of the services on the independence of Deloitte.

The policy also requires the Controller to update the Audit Committee throughout the year as to the services provided by Deloitte and the costs of those services. The policy also requires Deloitte to annually confirm its independence in accordance with SEC and NYSE standards. The Audit Committee will assess the adequacy of this policy as it deems necessary and revise accordingly.

Set forth in the table below is certain information relating to the aggregate fees billed by Deloitte for professional services rendered to us for the fiscal years ended December 31, 2009, and December 31, 2008.

	2009	2008
Audit fees	$3,581,000	$3,673,000
Audit-related fees	91,000	94,000
Tax fees	19,000	22,000
Other fees	—	—
Total Fees	$3,691,000	$3,789,000

Audit fees include fees billed for services rendered in connection with (i) the audits of our annual financial statements and those of our SEC reporting subsidiaries (Carolina Power & Light Company and Florida Power Corporation); (ii) the audit of the effectiveness of our internal control over financial reporting; (iii) the reviews of the financial statements included in our Quarterly Reports on Form 10-Q and those of our SEC reporting subsidiaries; (iv) accounting consultations arising as part of the audits; and (v) audit services in connection with statutory, regulatory or other filings, including comfort letters and consents in connection with SEC filings and financing transactions. Audit fees for 2009 and 2008 also include $1,265,000 and $1,264,000, respectively, for services in connection with the Sarbanes-Oxley Act Section 404 and the related PCAOB Standard No. 2 relating to our internal control over financial reporting.

Audit-related fees include fees billed for (i) special procedures and letter reports; (ii) benefit plan audits when fees are paid by us rather than directly by the plan; and (iii) accounting consultations for prospective transactions not arising directly from the audits.

Tax fees include fees billed for tax compliance matters and tax planning and advisory services.

The Audit Committee has concluded that the provision of the non-audit services listed above as "Tax fees" is compatible with maintaining Deloitte's independence.

None of the services provided required approval by the Audit Committee pursuant to the *de minimis* waiver provisions described above.

PROPOSAL 2—RATIFICATION OF SELECTION OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Audit and Corporate Performance Committee of our Board of Directors (the "Audit Committee") has selected Deloitte & Touche LLP ("Deloitte & Touche") as our independent registered public accounting firm for the fiscal year ending December 31, 2010, and has directed that management submit the selection of that independent registered public accounting firm for ratification by the shareholders at the 2010 Annual Meeting of the Shareholders. Deloitte & Touche has served as the independent registered public accounting firm for our Company and its predecessors since 1930. In selecting Deloitte & Touche, the Audit Committee considered carefully Deloitte & Touche's previous performance for us, its independence with respect to the services to be performed and its general reputation for adherence to professional auditing standards. A representative of Deloitte & Touche will be present at the Annual Meeting of Shareholders, will have the opportunity to make a statement and will be available to respond to appropriate questions. Shareholder ratification of the selection of Deloitte & Touche as our independent registered public accounting firm is not required by our By-Laws or otherwise. However, we are submitting the selection of Deloitte & Touche to the shareholders for ratification as a matter of good corporate practice. If the shareholders fail to ratify the selection, the Audit Committee will reconsider whether or not to retain Deloitte & Touche. Even if the shareholders ratify the selection, the Audit Committee, in its discretion, may direct the appointment of a different independent registered public accounting firm at any time during the year if it is determined that such a change would be in the best interest of the Company and its shareholders.

Valid proxies received pursuant to this solicitation will be voted in the manner specified. Where no specification is made, the shares represented by the accompanying proxy will be voted "**FOR**" the ratification of the selection of Deloitte & Touche as our independent registered public accounting firm. Votes (other than votes withheld) will be cast pursuant to the accompanying proxy for the ratification of the selection of Deloitte & Touche.

The proposal to ratify the selection of Deloitte & Touche to serve as our independent registered public accounting firm for the fiscal year ending December 31, 2010, requires approval by a majority of the votes actually cast by holders of Common Stock present in person or represented by proxy at the Annual Meeting of Shareholders and entitled to vote thereon. Abstentions from voting and broker nonvotes will not count as shares voted and will not have the effect of a "negative" vote, as described in more detail under the heading "PROXIES" on page 2.

The Audit Committee and the Board of Directors recommend a vote "**FOR**" the ratification of the selection of Deloitte & Touche as our independent registered public accounting firm.

PROPOSAL 3—ADOPTION OF A "HOLD-INTO-RETIREMENT" POLICY FOR EQUITY AWARDS

One of our shareholders has submitted the proposal set forth below relating to the adoption of a "hold-into-retirement" policy for equity awards. Upon written or oral request, the Company will provide the name, address and share ownership of the proponent. Any such requests should be directed to our Corporate Secretary. For the reasons set forth after the proposal, the Board recommends a vote **"AGAINST"** the proposal.

Resolved: That stockholders of Progress Energy, Inc. ("Company") urge the Compensation Committee of the Board of Directors (the "Committee") to adopt a policy requiring that senior executives retain a significant percentage of shares acquired through equity compensation programs until two years following the termination of their employment (through retirement or otherwise), and to report to stockholders regarding the policy before Company 2011 annual meeting of stockholders. The stockholders recommend that the Committee not adopt a percentage lower than 75% of net after-tax shares. The policy should address the permissibility of transactions such as hedging transactions which are not sales but reduce the risk of loss to the executive.

Supporting Statement:

Equity-based compensation is an important component of senior executive compensation at the Company.

Requiring senior executives to hold a significant portion of shares obtained through compensation plans after the termination of employment would focus them on Company long-term success and would better align their interests with those of Company stockholders. In the context of the current financial climate, we believe it is imperative that companies reshape their compensation policies and practices to discourage excessive risk-taking and promote long-term, sustainable value creation. A 2002 report by a commission of The Conference Board endorsed the idea of a holding requirement, stating that the long-term focus promoted thereby "may help prevent companies from artificially propping up stock prices over the short-term to cash out options and making other potentially negative short-term decisions."

The Company has established stock ownership guidelines for executive officers. The guidelines were increased in 2009 to a minimum level of ownership of five times base salary for the Chief Executive Officer ("CEO"), four times base salary for the Chief Operating Officer ("COO"), and three times base salary for the Chief Financial Officer and Presidents/Executive Vice Presidents/Senior Vice Presidents.

We believe this policy does not go far enough to ensure that equity compensation builds executive ownership. We also view a retention requirement approach as superior to a stock ownership guideline because a guideline loses effectiveness once it has been satisfied.

We urge stockholders to vote for this proposal.

COMPANY RESPONSE

The Board and management oppose this shareholder proposal and recommend a vote "AGAINST" the proposal for the reasons set forth below:

The Board has considered this proposal and believes that its adoption is unnecessary and not in the best interests of the Company or its shareholders. For the reasons discussed below, the Board recommends that you vote **"AGAINST"** adoption of this proposal.

- **The Board of Directors believes that the Company's equity compensation policies have been essential to attracting and retaining experienced and effective executives and motivating them to perform in the best interests of the Company and its shareholders.**

The Board of Directors believes strongly that equity compensation and mandatory equity ownership promote accountability and encourage executives to enhance long-term shareholder value. This belief is reflected in our compensation policies and practices. Equity ownership is a fundamental element of the Company's executive compensation program and provides an essential source of incentive and motivation for our senior executives. Approximately 60% of total target compensation for our executive officers is provided in equity and focused on long-term performance. The Company's executive compensation program is carefully designed to provide a competitive level of at-risk and performance-based incentives through a combination of equity awards, including restricted stock units and performance shares. The Board believes that the proposal would result in an overemphasis on post-retirement compensation and undermine the effectiveness of the Company's existing executive compensation programs.

- **The Board believes that our stock ownership guidelines ensure that the Company's executive officers have a significant equity stake in the future of the Company.**

The Company's stock ownership guidelines are consistent with those of the peer group the Organization and Compensation Committee used to benchmark compensation and with which we compete for executive talent. Our guidelines are consistent with the 50th percentile for both the base salary multiple and the time required to meet ownership targets. The Company's CEO currently holds 8.5 times his base salary although our guidelines require him to hold 5 times his base salary in equity compensation. All of our senior executives are in compliance with the Company's stock ownership guidelines.

The proposal states that the two-year post retirement retention approach is "superior" because the guideline approach loses effectiveness once the guidelines have been met. The Board of Directors does not believe this is true, as executives are continually expected to meet the guidelines, even during market downturns. Moreover, the ownership levels established in the guidelines represent a significant amount of money and, as a result, are a regular and strong source of alignment with shareholders' interests. Finally, three to five times an executive's salary is a significant amount that is not easily dismissed just because further accumulation of equity is no longer necessary.

- **Because we are in a highly regulated industry, our compensation programs do not provide incentives for executive officers to take unnecessary and excessive risks that threaten the value of the Company.**

Post-termination holding periods are purported to prevent executives from taking actions that would cause the price of a company's stock to rise as they depart in order for them to be able to sell their holdings at an elevated price before their behavior is discovered and corrected. As an integrated electric utility, primarily engaged in the regulated utility business, the Company is highly regulated at both the federal and state levels. State and federal regulators set the parameters within which the Company can operate. The state regulators have authority to review and approve the rates we charge our customers. The regulators review certain of our costs and investments, and approve our recovery of them from customers only if they determine that the costs and investments were reasonable and prudent when incurred. In such a regulated environment, excessive risk-taking is neither encouraged nor allowed. Therefore, it is highly unlikely our executives would be able to successfully engage in the type of behavior the proposal is intended to protect against.

- **The Board believes that the type of policy mandated by the proposal, with its high retention threshold and post-retirement holding period, is not a prevalent practice and may lead to an early loss of executive talent.**

The two-year post termination requirement would limit our executives' financial resources at a time when they no longer have any control over our operations or results. Long-term alignment is, of course, important. However, for our compensation programs to have value, participants should be permitted the flexibility for some degree of diversification. In the absence of this balanced approach, executives who have been successful in enhancing shareholder value may choose to leave the Company earlier than they otherwise would if they are interested in selling any of their shares in order to share in the value they have helped to create. As a result, the proposal could lead to an early loss of experienced talent and make it more difficult and costly to attract, motivate and retain executives.

- **The Board believes that the type of policy mandated by the proposal will result in executives' failure to take the actions needed to ensure the Company's long-term success.**

As noted above, the Company is a member of a highly regulated industry in which excessive risk-taking is neither encouraged nor allowed. The Company recognizes, however, that some amount of risk-taking is inherent in its business and is necessary in order to increase profitability and long-term shareholder value. If executives are too focused on preserving the value of their equity holdings in the Company into retirement, they may become reluctant to pursue strategies or undertake projects or capital investments that could be beneficial to the Company. The proposed policy would leave our executives almost completely dependent on the value of the Company stock, potentially resulting in them becoming unduly risk averse to the detriment of our shareholders.

The Board of Directors remains committed to the design and implementation of equity compensation programs and stock ownership guidelines that best align the interests of the Company's leadership with those of our shareholders, provide competitive compensation that requires executives to own a significant portion of Company stock and ensure that executives have the appropriate flexibility to manage their personal financial affairs. We believe the Company's existing programs and guidelines achieve these objectives and are essential to our ability to attract, motivate and retain talented executives.

YOUR BOARD OF DIRECTORS AND MANAGEMENT URGE YOU TO VOTE AGAINST THIS PROPOSAL

FINANCIAL STATEMENTS

Our 2009 Annual Report, which includes financial statements as of December 31, 2009 and 2008, and for each of the three years in the period ended December 31, 2009, together with the report of Deloitte & Touche LLP, our independent registered public accounting firm, was mailed to those who were shareholders of record as of the close of business on March 5, 2010.

FUTURE SHAREHOLDER PROPOSALS

Shareholder proposals submitted for inclusion in the proxy statement for our 2011 Annual Meeting must be received no later than December 1, 2010, at our principal executive offices, addressed to the attention of:

John R. McArthur
Executive Vice President and Corporate Secretary
Progress Energy, Inc.
P.O. Box 1551
Raleigh, North Carolina 27602-1551

Upon receipt of any such proposal, we will determine whether or not to include such proposal in the proxy statement and proxy in accordance with regulations governing the solicitation of proxies.

In order for a shareholder to nominate a candidate for director, under our By-Laws timely notice of the nomination must be received by the Corporate Secretary of the Company either by personal delivery or by United States registered or certified mail, postage pre-paid, not later than the close of business on the 120th calendar day before the date our proxy statement was released to shareholders in connection with the previous year's annual meeting. In no event shall the public announcement of an adjournment or postponement of an annual meeting or the fact that an annual meeting is held after the anniversary of the preceding annual meeting commence a new time period for a shareholder's giving of notice as described above. The shareholder filing the notice of nomination must include:

- As to the shareholder giving the notice:
  - the name and address of record of the shareholder who intends to make the nomination, the beneficial owner, if any, on whose behalf the nomination is made and of the person or persons to be nominated;
  - the class and number of our shares that are owned by the shareholder and such beneficial owner;
  - a representation that the shareholder is a holder of record of our shares entitled to vote at such meeting and intends to appear in person or by proxy at the meeting to nominate the person or persons specified in the notice; and
  - a description of all arrangements, understandings or relationships between the shareholder and each nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the shareholder.
- As to each person whom the shareholder proposes to nominate for election as a director:
  - the name, age, business address and, if known, residence address of such person;
  - the principal occupation or employment of such person;
  - the class and number of shares of our stock that are beneficially owned by such person;

- any other information relating to such person that is required to be disclosed in solicitations of proxies for election of directors or is otherwise required by the rules and regulations of the SEC promulgated under the Securities Exchange Act of 1934; and
- the written consent of such person to be named in the proxy statement as a nominee and to serve as a director if elected.

In order for a shareholder to bring other business before a shareholder meeting, we must receive timely notice of the proposal not later than the close of business on the 60th day before the first anniversary of the immediately preceding year's annual meeting. Such notice must include:

- the information described above with respect to the shareholder proposing such business;
- a brief description of the business desired to be brought before the annual meeting, including the complete text of any resolutions to be presented at the annual meeting, and the reasons for conducting such business at the annual meeting; and
- any material interest of such shareholder in such business.

These requirements are separate from the requirements a shareholder must meet to have a proposal included in our proxy statement.

Any shareholder desiring a copy of our By-Laws will be furnished one without charge upon written request to the Corporate Secretary. A copy of the By-Laws, as amended and restated on May 10, 2006, was filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, and is available at the SEC's Web site at *www.sec.gov*.

OTHER BUSINESS

The Board of Directors does not intend to bring any business before the meeting other than that stated in this Proxy Statement. The Board knows of no other matter to come before the meeting. If other matters are properly brought before the meeting, it is the intention of the Board of Directors that the persons named in the enclosed proxy will vote on such matters pursuant to the proxy in accordance with their best judgment.

Exhibit A

POLICY AND PROCEDURES WITH RESPECT TO RELATED PERSON TRANSACTIONS

A. Policy Statement

The Company's Board of Directors (the "Board") recognizes that Related Person Transactions (as defined below) can present heightened risks of conflicts of interest or improper valuation or the perception thereof. Accordingly, the Company's general policy is to avoid Related Person Transactions. Nevertheless, the Company recognizes that there are situations where Related Person Transactions might be in, or might not be inconsistent with, the best interests of the Company and its stockholders. These situations could include (but are not limited to) situations where the Company might obtain products or services of a nature, quantity or quality, or on other terms, that are not readily available from alternative sources or when the Company provides products or services to Related Persons (as defined below) on an arm's length basis on terms comparable to those provided to unrelated third parties or on terms comparable to those provided to employees generally. The Company, therefore, has adopted the procedures set forth below for the review, approval or ratification of Related Person Transactions.

This Policy has been approved by the Board. The Corporate Governance Committee (the "Committee") will review and may recommend to the Board amendments to this Policy from time to time.

B. Related Person Transactions

For the purposes of this Policy, a "Related Person Transaction" is a transaction, arrangement or relationship, including any indebtedness or guarantee of indebtedness, (or any series of similar transactions, arrangements or relationships) in which the Company (including any of its subsidiaries) was, is or will be a participant and the amount involved exceeds $120,000, and in which any Related Person had, has or will have a direct or indirect material interest.

For purposes of this Policy, a "Related Person" means:

1. any person who is, or at any time since the beginning of the Company's last fiscal year was, a director or executive officer (i.e. members of the Senior Management Committee and the Controller) of the Company, Progress Energy Carolinas, Inc., or Progress Energy Florida, Inc. or a nominee to become a director of the Company, Progress Energy Carolinas, Inc., or Progress Energy Florida, Inc.;

2. any person who is known to be the beneficial owner of more than 5% of any class of the voting securities of the Company or its subsidiaries;

3. any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law of the director, executive officer, nominee or more than 5% beneficial owner, and any person (other than a tenant or employee) sharing the household of such director, executive officer, nominee or more than 5% beneficial owner; and

4. any firm, corporation or other entity in which any of the foregoing persons is employed or is a general partner or principal or in a similar position or in which such person has a 5% or greater beneficial ownership interest.

C. Approval Procedures

1. The Board has determined that the Committee is best suited to review and approve Related Person Transactions. Accordingly, at each calendar year's first regularly scheduled Committee meeting, management shall recommend Related Person Transactions to be entered into by the Company for that calendar year, including the proposed aggregate value of such transactions if applicable. After review, the Committee shall approve or disapprove such transactions and at each subsequently scheduled meeting, management shall update the Committee as to any material change to those proposed transactions.

2. In determining whether to approve or disapprove each related person transaction, the Committee will consider various factors, including the following:

   - the identity of the related person;
   - the nature of the related person's interest in the particular transaction;
   - the approximate dollar amount involved in the transaction;
   - the approximate dollar value of the related person's interest in the transaction;
   - whether the related person's interest in the transaction conflicts with his obligations to the Company and its shareholders;
   - whether the transaction will provide the related person with an unfair advantage in his dealings with the Company; and
   - whether the transaction will affect the related person's ability to act in the best interests of the Company and its shareholders

The Committee will only approve those related person transactions that are in, or are not inconsistent with, the best interests of the Company and its shareholders.

3. In the event management recommends any further Related Person Transactions subsequent to the first calendar year meeting, such transactions may be presented to the Committee for approval at the next Committee meeting. In these instances in which the Legal Department, in consultation with the President and Chief Operating Officer, determines that it is not practicable or desirable for the Company to wait until the next Committee meeting, any further Related Person Transactions shall be submitted to the Chair of the Committee (who will possess delegated authority to act between Committee meetings). The Chair of the Committee shall report to the Committee at the next Committee meeting any approval under this Policy pursuant to his/her delegated authority.

4. No member of the Committee shall participate in any review, consideration or approval of any Related Person Transaction with respect to which such member or any of his or her immediate family members is the Related Person. The Committee (or the Chair) shall approve only those Related Person Transactions that are in, or are not inconsistent with; the best interests of the Company and its stockholders, as the Committee (or the Chair) determines in good faith. The Committee or Chair, as applicable, shall convey the decision to the President and Chief Operating Officer, who shall convey the decision to the appropriate persons within the Company.

D. Ratification Procedures

In the event the Company's Chief Executive Officer, President and Chief Operating Officer, Chief Financial Officer or General Counsel becomes aware of a Related Person Transaction that has not been previously approved or previously ratified under this Policy, said officer shall immediately notify the Committee or Chair of the Committee, and the Committee or Chair shall consider all of the relevant facts and circumstances regarding the Related Person Transaction. Based on the conclusions reached, the Committee or the Chair shall evaluate all options, including but not limited to ratification, amendment, termination or recession of the Related Person Transaction, and determine how to proceed.

E. Review of Ongoing Transactions

At the Committee's first meeting of each calendar year, the Committee shall review any previously approved or ratified Related Person Transactions that remain ongoing and have a remaining term of more than six months or remaining amounts payable to or receivable from the Company of more than $120,000. Based on all relevant facts and circumstances, taking into consideration the Company's contractual obligations, the Committee shall determine if it is in the best interests of the Company and its stockholders to continue, modify or terminate the Related Person Transaction.

F. Disclosure

All Related Person Transactions are to be disclosed in the filings of the Company, Progress Energy Carolinas, Inc. or Progress Energy Florida, Inc., as applicable, with the Securities and Exchange Commission as required by the Securities Act of 1933 and the Securities Exchange Act of 1934 and related rules. Furthermore, all Related Person Transactions shall be disclosed to the Corporate Governance Committee of the Board and any material Related Person Transaction shall be disclosed to the full Board of Directors.

The material features of this Policy shall be disclosed in the Company's annual report on Form 10-K or in the Company's proxy statement, as required by applicable laws, rules and regulations.

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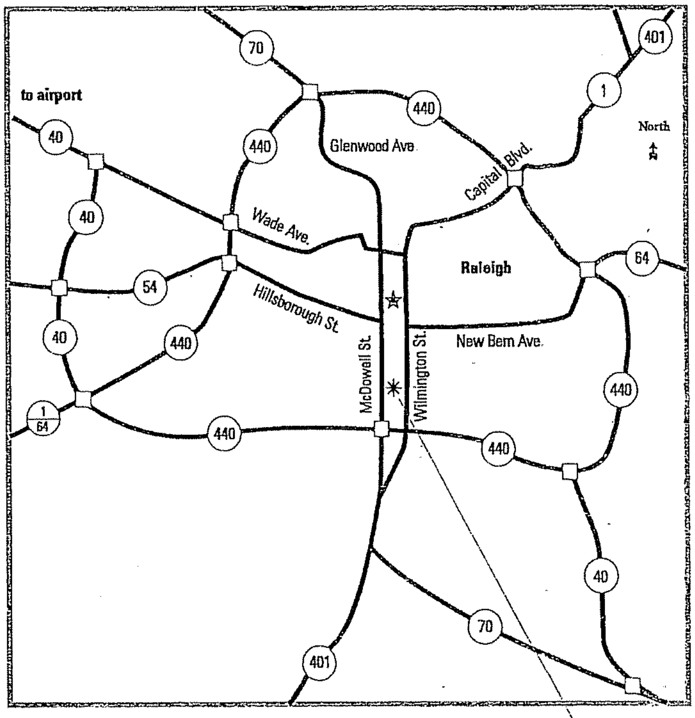
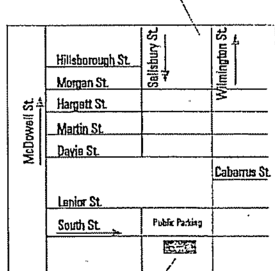
Directions to Progress Energy's 2010 Annual Shareholders' Meeting

Progress Energy Center for the Performing Arts
2 E. South Street, Raleigh, North Carolina





Progress Energy Center for the Performing Arts

002CS-61034

Board of Directors

William D. Johnson

Chairman, President and Chief Executive Officer, Progress Energy, Inc. Raleigh, N.C.

Elected to the board in 2007. Serves as Chairman, Progress Energy Carolinas and Chairman, Progress Energy Florida.

John D. Baker II

President and Chief Executive Officer, Patriot Transportation Holding, Inc. (provides transportation services and real estate operations). Jacksonville, Fla.

Elected to the board in 2009 and sits on the following committees: Finance; Organization and Compensation.

James E. Bostic, Jr.

Managing Director, HEP & Associates (business consulting) and retired Executive Vice President, Georgia-Pacific Corp. (manufacturer and distributor of tissue, paper, packaging, building products, pulp and related chemicals). Atlanta, Ga.

Elected to the board in 2002 and sits on the following committees: Audit and Corporate Performance; Nuclear Project Oversight; Operations and Nuclear Oversight.

Harris E. DeLoach, Jr.

Chairman, 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; Nuclear Project Oversight; Operations and Nuclear Oversight (Chair); Organization and Compensation.

James B. Hyler, Jr.

Retired Vice Chairman and Chief Operating Officer, First Citizens Bank. Raleigh, N.C.

Elected to the board in 2008 and sits on the following committees: Finance; Organization and Compensation.

Robert W. Jones

Sole owner, Turtle Rock Group, LLC (financial advisory consulting firm). Bedford, N.Y.

Elected to the board in 2007 and sits on the following committees: Corporate Governance; Finance (Chair); Organization and Compensation.

W. Steven Jones

Dean (Emeritus) and Professor of Strategy and Organizational Behavior at the Kenan-Flagler Business School at the University of North Carolina at Chapel Hill and formerly Chief Executive Officer of Suncorp-Metway Ltd. (banking and insurance in Australia). Chapel Hill, N.C.

Elected to the board in 2005 and sits on the following committees: Audit and Corporate Performance; Nuclear Project Oversight; Operations and Nuclear Oversight.

Melquiades R. "Mel" Martinez

Partner, specializing in public policy, DLA Piper (an international law firm) and former U.S. Senator from the state of Florida and former Secretary of the U.S. Department of Housing and Urban Development. Orlando, Fla.

Elected to the board in 2010 and sits on the following committees: Audit and Corporate Performance; Operations and Nuclear Oversight.

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). Corning, N.Y

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

John H. Mullin, III

Chairman, Ridgeway Farm, LLC (farming and timber management) and formerly a Managing Director, Dillon, Read & Co. (investment bankers). Brookneal, Va.

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

Charles W. Pryor, Jr.

Chairman, Urenco Investments, Inc. (global provider of services and technology to the nuclear generation industry). Lynchburg, Va.

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

Carlos A. Saladrigas

Chairman and Chief Executive Officer, Regis HRG (provides a full suite of outsourced human resources services to small and midsized businesses). Previously served as Chairman, Premier American Bank and retired Chief Executive Officer, ADP TotalSource. Miami, Fla.

Elected to the board in 2001 and sits on the following committees: Audit and Corporate Performance; Finance.

Theresa M. Stone

Executive Vice President and Treasurer, Massachusetts Institute of Technology and retired President, Lincoln Financial Media (financial services company). Boston, Mass.

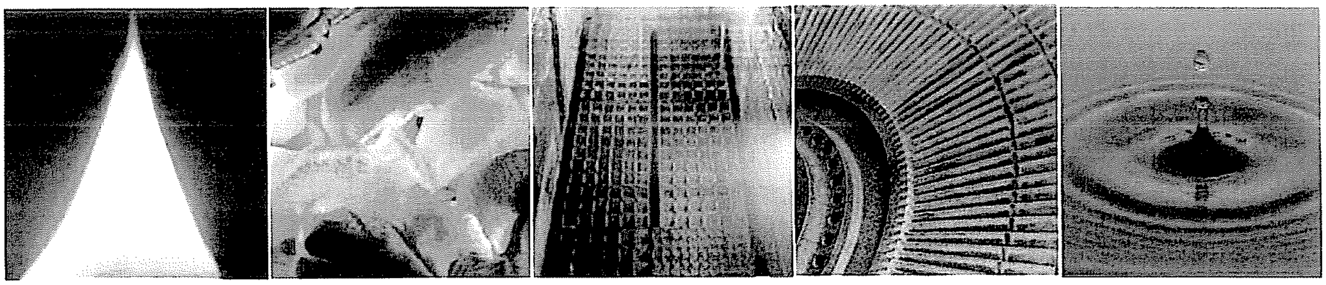
Elected to the board in 2005 and sits on the following committees: Audit and Corporate Performance (Chair); Corporate Governance; Finance.

Alfred C. Tollison, Jr.

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

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

Progress Energy, Inc.
P.O. Box 1551
Raleigh, N.C. 27602-1551
progress-energy.com



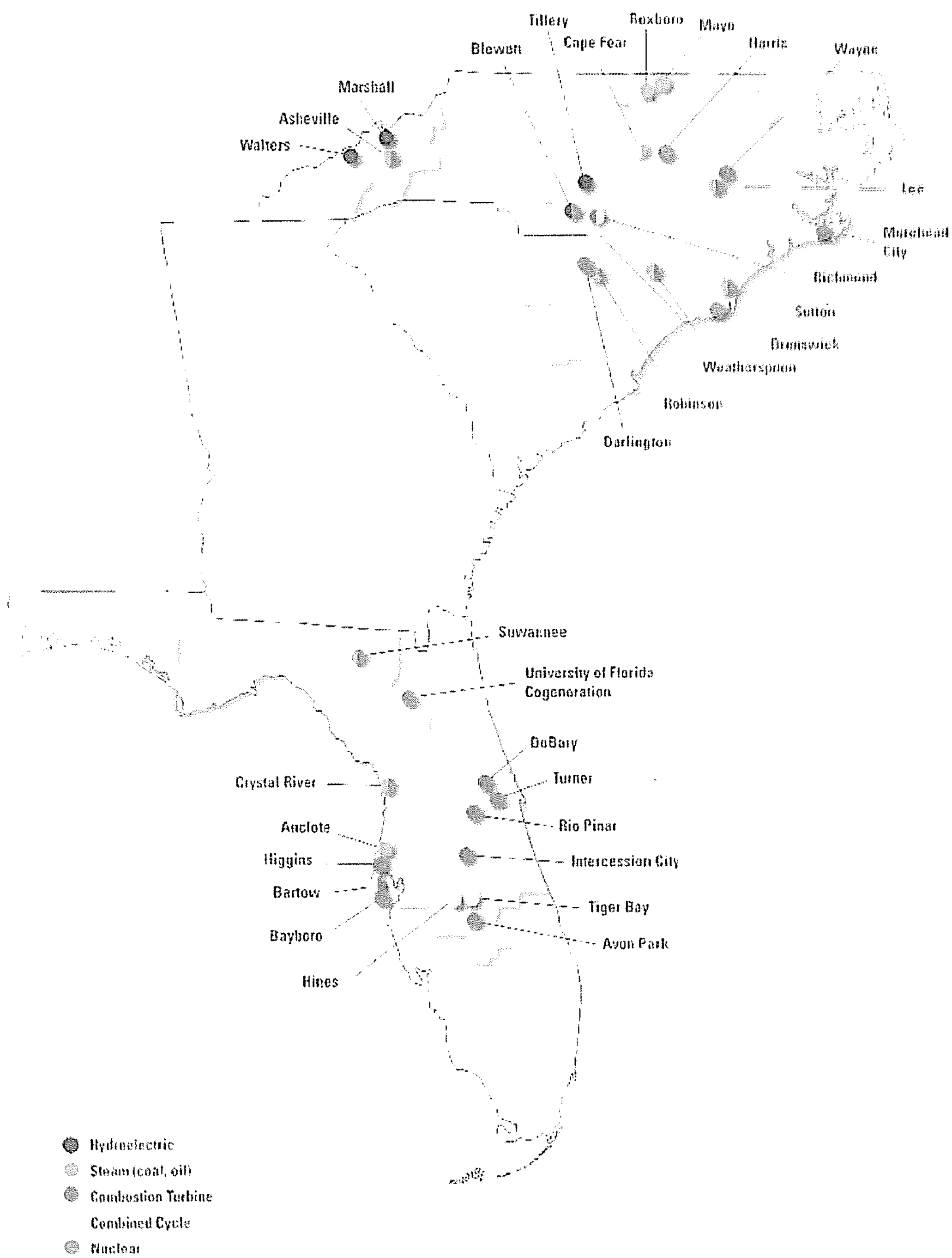
Progress Energy Generating Plants

Progress Energy

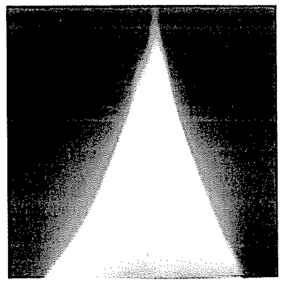
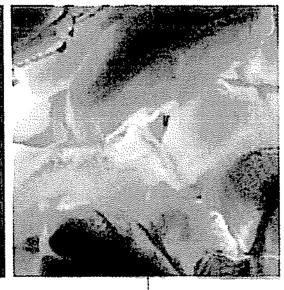
Progress Energy operates power-generating facilities at 32 sites in North Carolina, South Carolina and Florida. Together, the company's power plant fleet is capable of generating more than 22,000 megawatts of electricity.

Progress Energy operates a diverse mix of plant technologies and fuel sources, including hydroelectric, nuclear, coal, oil and natural gas. This fuel diversity enables the company to minimize cost impacts from any one fuel source and ensures reliable power for our residential, commercial, industrial and wholesale customers.

Electricity cannot be stored. That means every minute of every day, Progress Energy's generating plants must match changing customer power demands. And each plant has an important role in the company's mission to provide safe, reliable and cost-effective power to the Southeast.

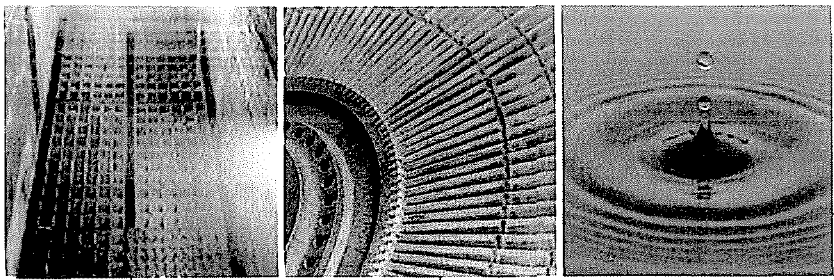


Progress Energy Regulated Service Areas

Generating Technologies

Five plants provide a total of 3,786 megawatts of generating capacity. Combined-cycle technology offers an efficient source of electricity with outstanding reliability. With attractive environmental and operating characteristics, our combined-cycle plants make up a valuable part of Progress Energy's generation mix.

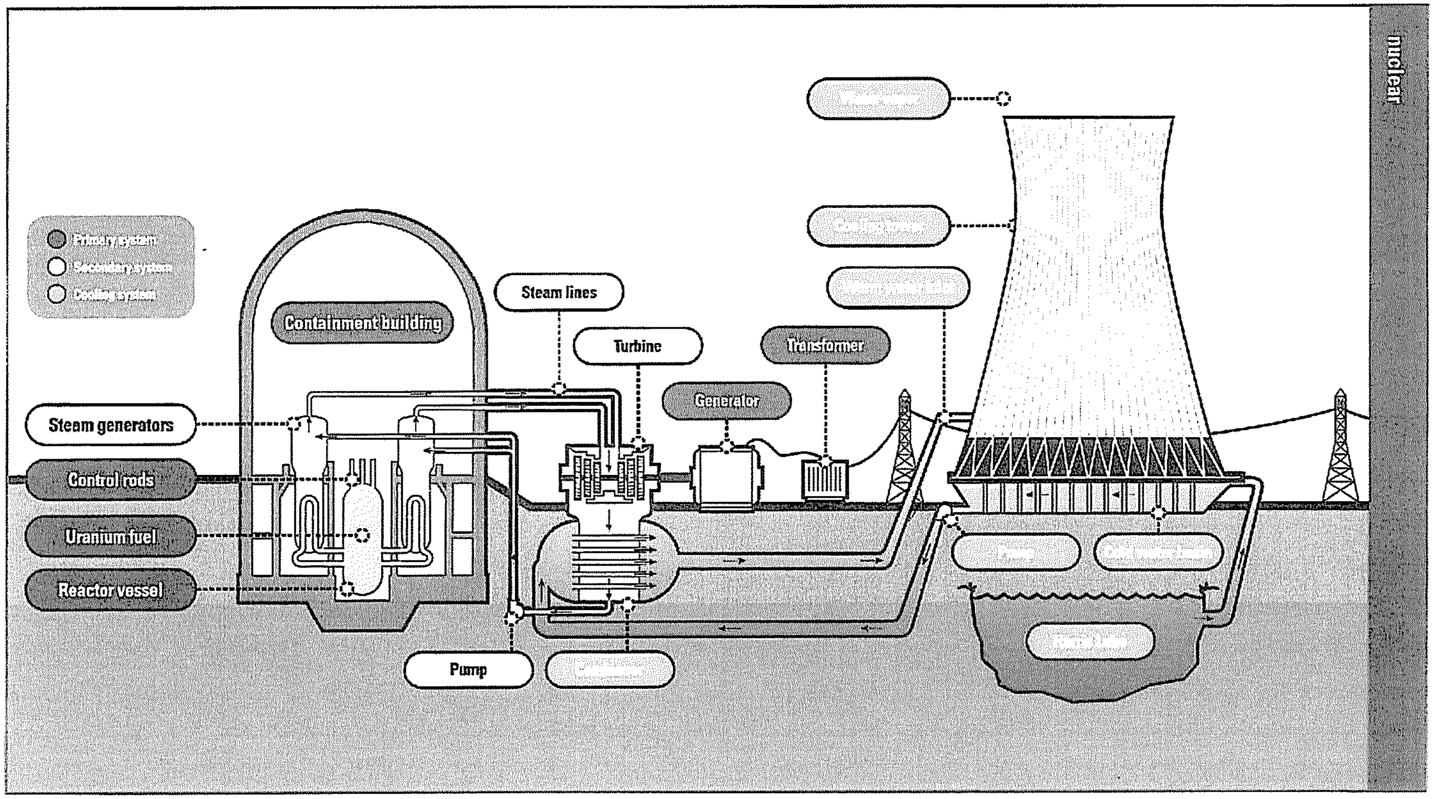


Progress Energy's 89 **combustion turbine** units have a combined generation capacity of 5,646 megawatts of power. These high-tech facilities can reach full power quickly, which enables Progress Energy to respond to peak demands and keep the cities and towns we serve running like clockwork.

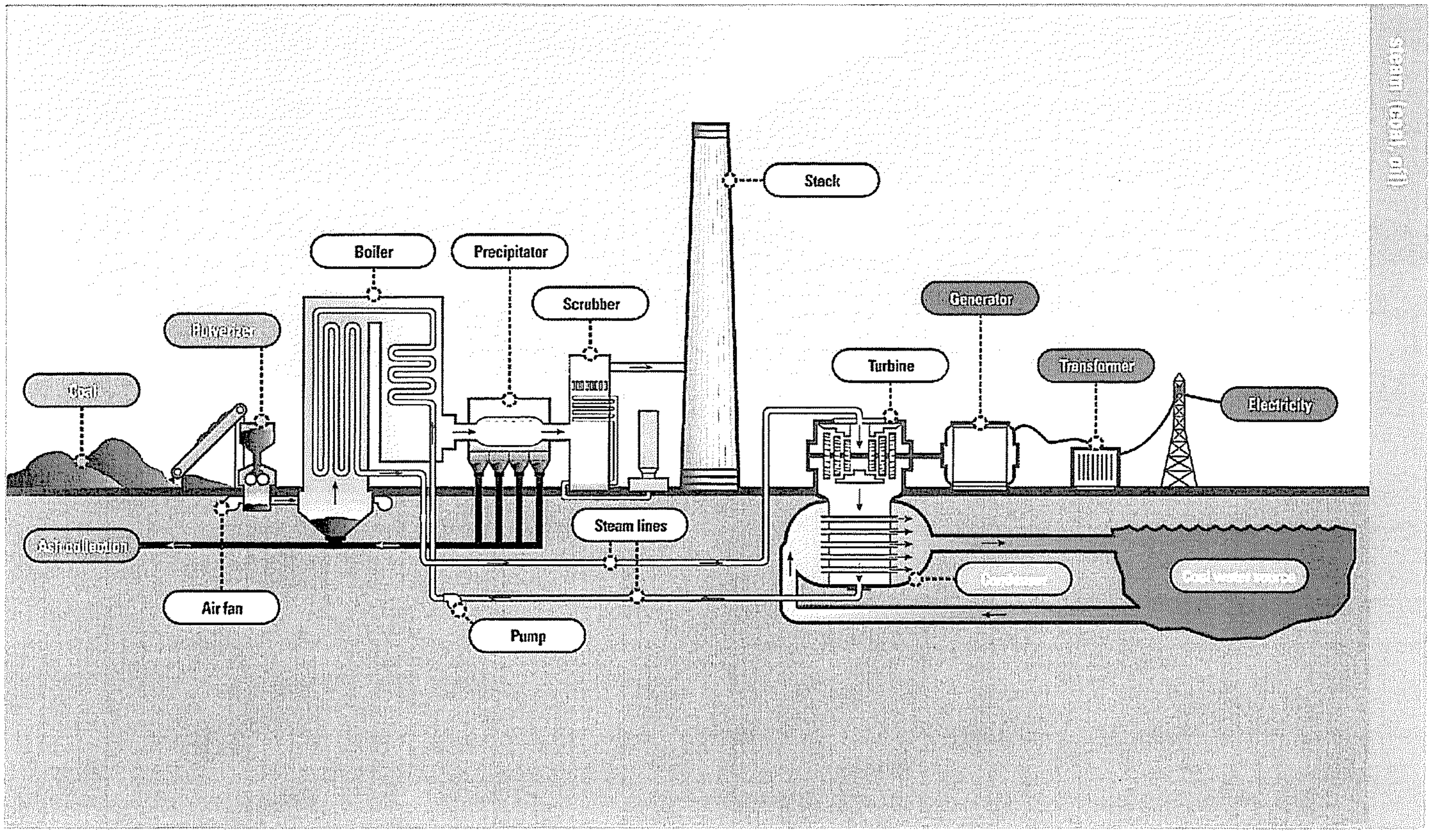
Nuclear power generation represents about 19 percent of Progress Energy's generating capability – 4,342 megawatts – enough electricity to power more than 2.5 million homes. In addition to being reliable, cost-effective and resource-efficient, nuclear energy is a safe and clean energy source that helps meet the increasing energy demands of today's technology-driven society.

Progress Energy owns and operates four **hydroelectric** plants along rivers throughout North Carolina. These stations provide valued, emission-free generation to the region. Together, our hydroelectric plants provide 225 megawatts of reliable, environmentally friendly power generation to complement our energy portfolio.

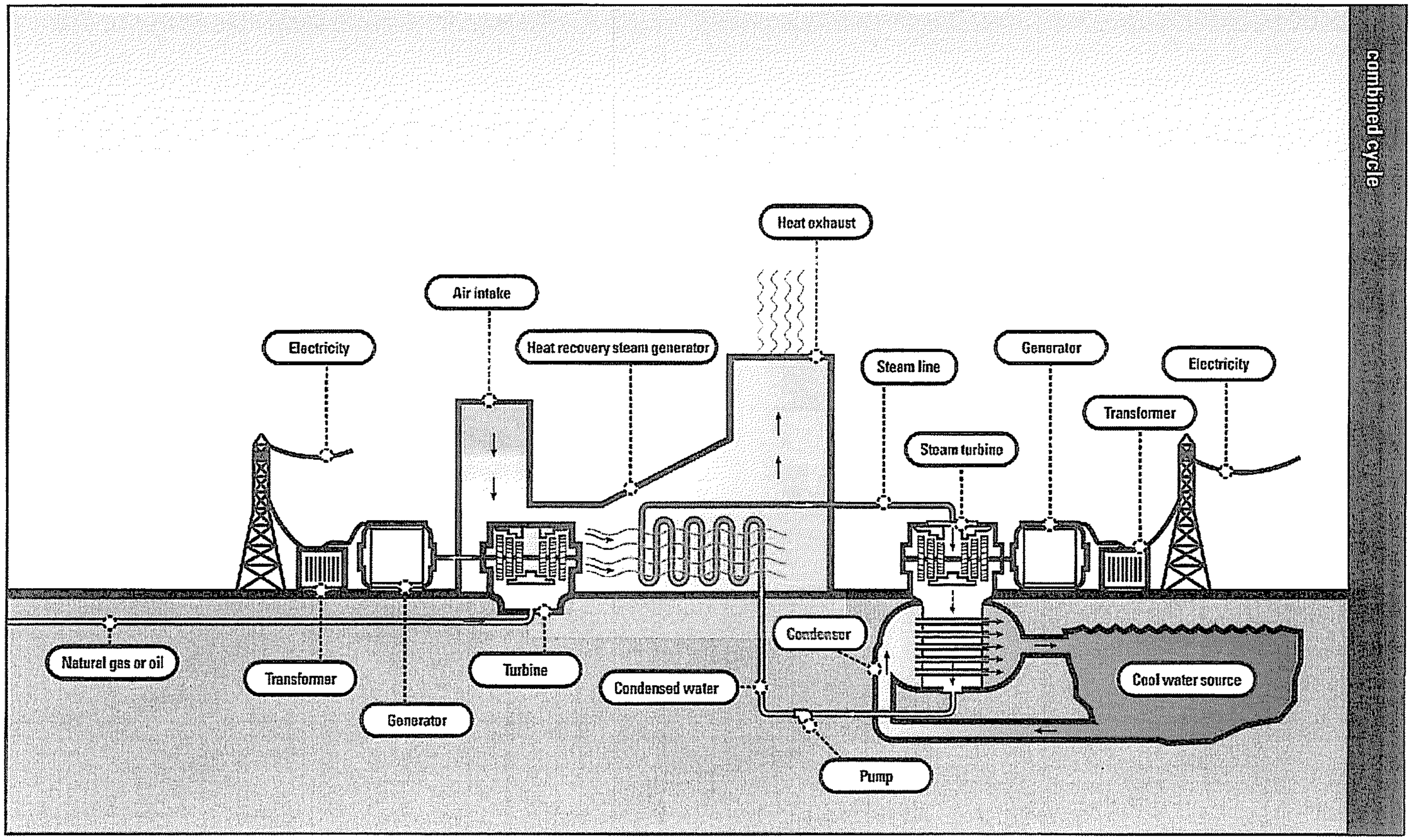
Our 11 coal- and oil-powered steam plants generate 8,599 megawatts of power to meet the daily energy needs of our customers. Maintaining diversity in our fuel mix allows us to adjust quickly to ever-changing energy prices and ensures Progress Energy's customers power that's not only reliable, but also affordable.



JOINT APPLICANTS
EXHIBIT D
PAGE 08

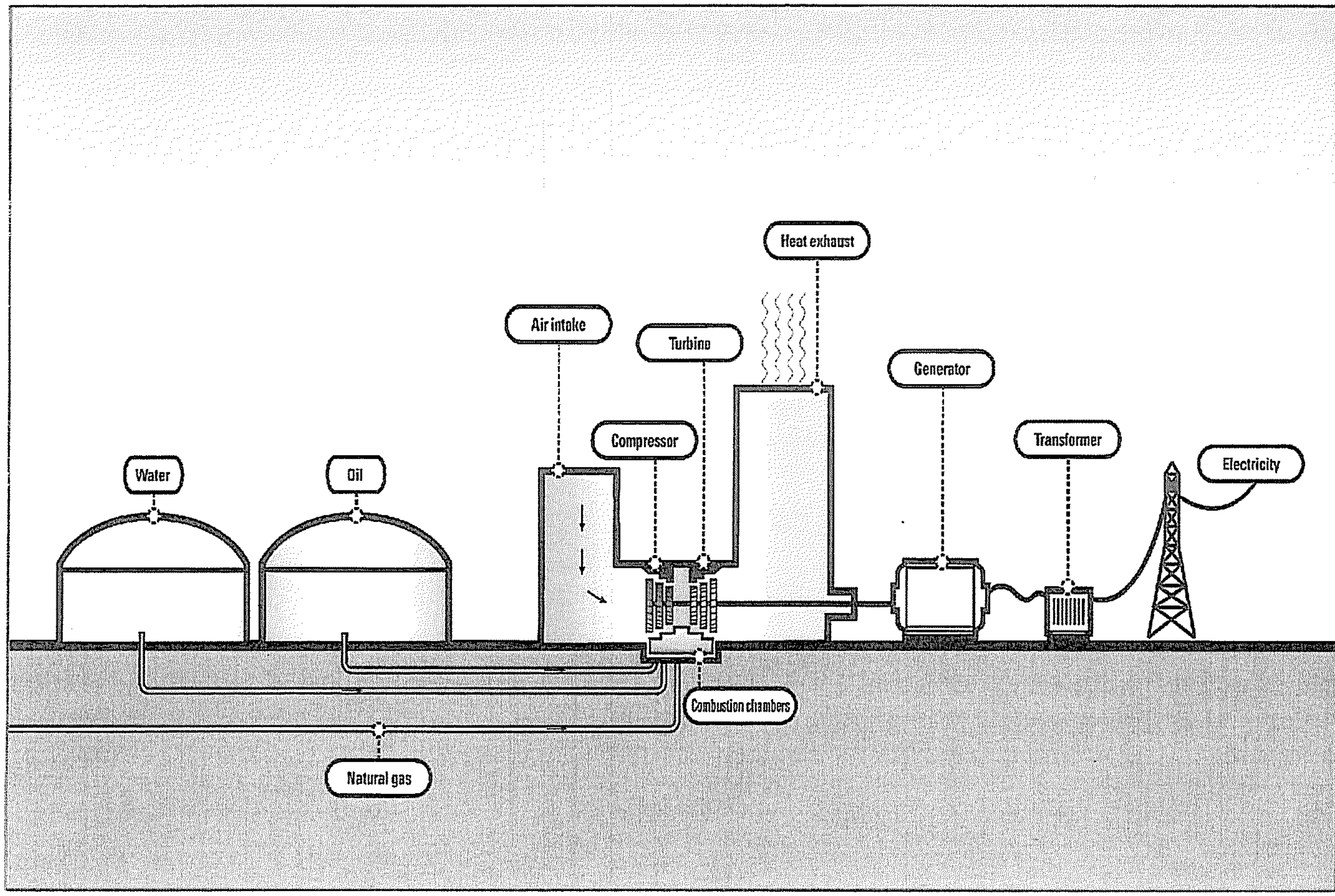


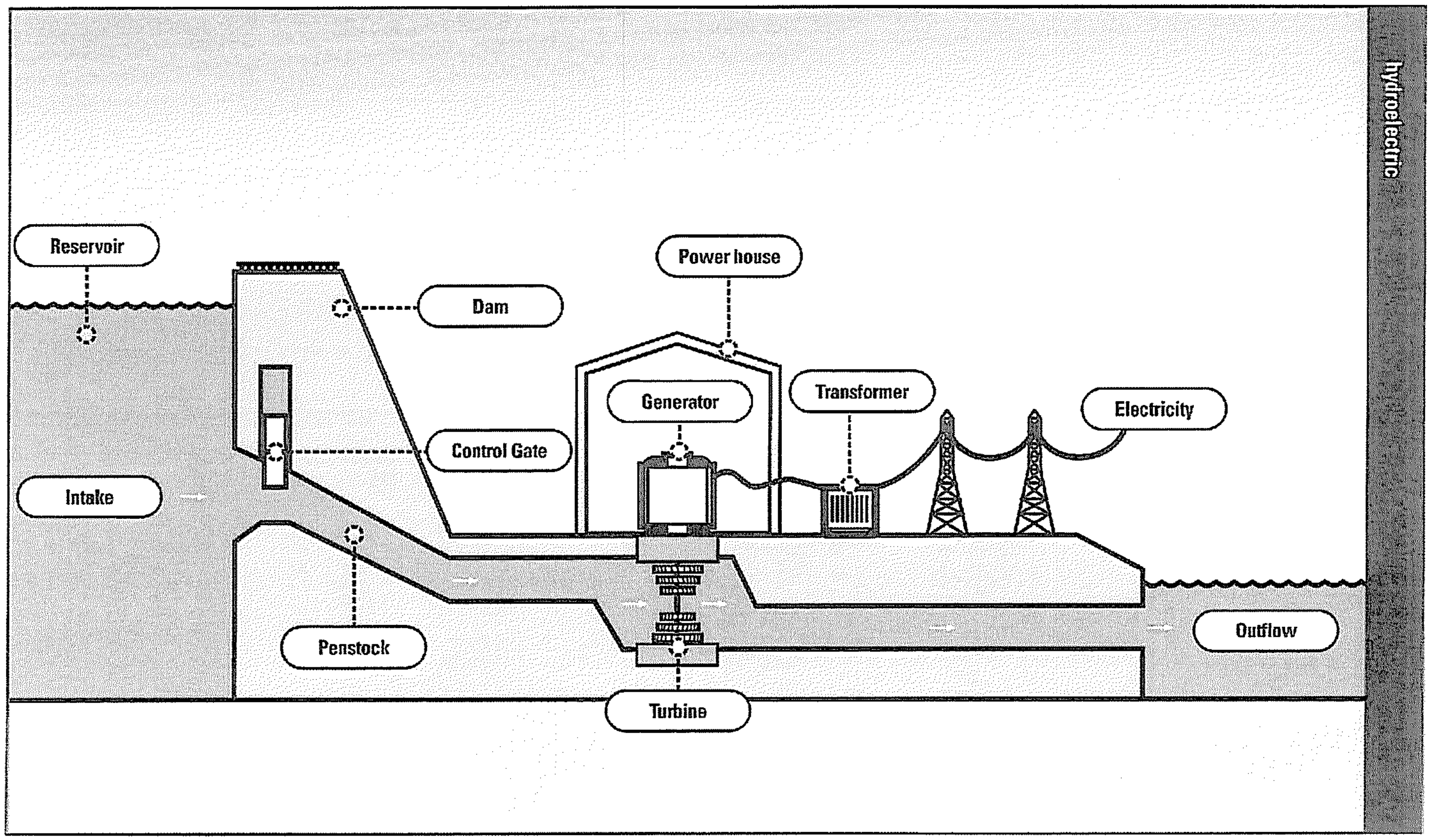
Note: not all coal plants have SCRs and scrubbers.



JOINT APPLICANTS
EXHIBIT D
PAGE 10

combustion turbine





JOINT APPLICANTS
EXHIBIT D
PAGE 12

Baseload plant A generating plant that typically runs 90 to 100 percent of the time to meet basic, constant electricity demand.

Boiler A vessel, usually consisting of metal sheets and tubes, in which water is boiled to produce steam.

Boiling water reactor (BWR) A type of nuclear reactor which boils water directly in the core to be sent to a turbine to generate electricity.

Coal A black or brownish solid combustible substance formed by the partial decomposition of vegetable matter without free access of air and under the influence of moisture, and often intense pressure and temperature. The rank of coal (anthracite, bituminous, subbituminous, and lignite) is determined by its heating value.

Condenser A large heat exchanger designed to cool exhaust steam so that it can be returned to the heat source as water.

Containment building A gastight shell or other enclosure around a nuclear reactor that confines fission products.

Control gate Gates that open on a dam and allow gravity to pull water into the intake structure.

Control rod A rod, plate or tube containing a material that readily absorbs neutrons, slowing the fission process.

Cooling tower A heat exchanger designed to aid in the cooling of water used to cool exhaust steam exiting the turbines of a power plant. Cooling towers transfer exhaust heat into the air instead of into a body of water.

Dam A barrier built across a waterway to control the flow of water.

Generator A machine that transforms mechanical energy into electric energy.

Heat recovery generator A heat exchanger that uses the heat rejected from a gas turbine. The waste heat is captured and is then used as input heat to a steam turbine to more efficiently create electricity.

Intake Gates on a dam that open and allow gravity to pull the water through the penstock

Intermediate plant A generating plant that typically runs about 50 to 60 percent of the time to meet electricity demand that exceeds the basic, continuous level.

Natural gas Naturally occurring mixtures of hydrocarbon gases and vapors, the more important of which are methane, ethane, propane, butane, pentane, and hexane.

Peaking plant A generating plant that typically runs less than 10 percent of the time to meet relatively short periods of heightened electricity demand on the hottest and coldest days.

Penstock A pipeline that leads from a reservoir to a turbine allowing water to build pressure as it flows through this pipe.

Powerhouse A hydroelectric plant structure housing a transformer.

Precipitator Air pollution control device that collects particles from gaseous emissions by mechanical or electrical means.

Pressurized water reactor (PWR) A type of power producing reactor which keeps the water surrounding the core under pressure. When the pressurized water is heated by the reactor, it is sent to a heat exchanger and it boils water that is kept at a lower pressure. This steam is then sent to a turbine to generate electricity.

Pulverizer A machine that reduces coal to a powder.

Reactor vessel An apparatus in which the nuclear fission chain reaction may be initiated, maintained and controlled, so that the accompanying energy is released at a specified rate. It includes fuel (uranium), a moderating material, control elements and instrumentation.

Reservoir Any holding area, natural or artificial, used to store, regulate or control water.

Scrubber A device that uses a liquid spray or solid sorbent to remove aerosol and gaseous pollutants from an air stream. The gases are removed either by absorption or by chemical reaction.

Selective catalytic reduction A method to reduce nitrogen oxide in which exhaust gases produced by a coal-fired electric generating unit pass though the SCR, where an ammonia or a urea solution reacts with the nitrogen oxide in the exhaust and converts it to nitrogen and water, prior to the exhaust going up the smokestack.

Stack A chimney or smokestack, a vertical pipe or flue, that exhausts gases and particulate matter to the atmosphere.

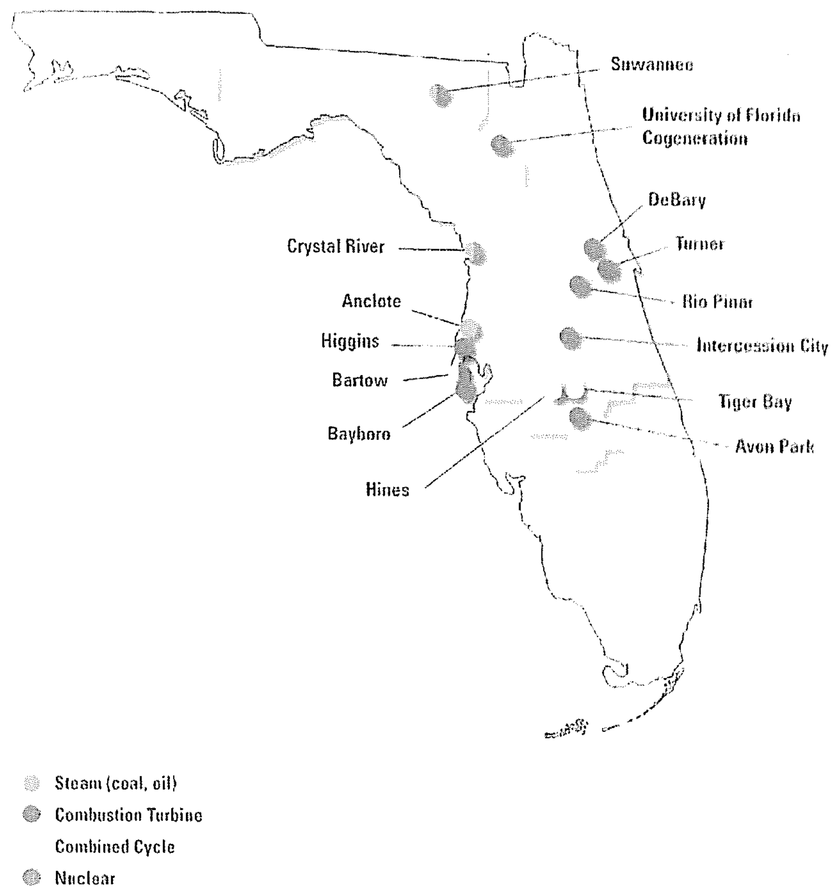
Steam generator A vessel containing water that uses a heat source to change water into steam.

Transformer An electromagnetic device for changing the voltage level of alternating-current electricity.

Turbine A part in some electric plants that is spun by a force of energy (e.g., air, water, steam, or a combustion engine) in order to turn the generator. It generally consists of a series of curved vanes or blades emanating from an axis that is turned by forcing air, steam or water past the vanes or blades.

Uranium The heaviest element normally found in nature. The fissile isotope uranium-235 is the principal nuclear fuel material used in today's nuclear power reactors. Uranium is a hard, shiny, metallic radioactive element. Its atomic number is 92, its atomic weight is 238, and its symbol is U.

Primary source of definitions: Edison Electric Institute Glossary of Electric Industry Terms, EEI (2005).

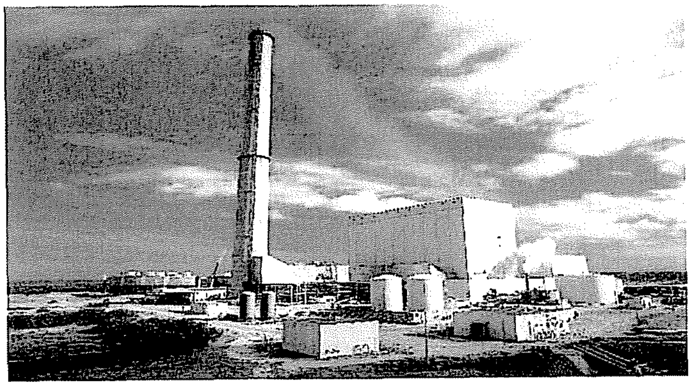


Progress Energy Regulated Service Areas

Florida

- Anclote
- Avon Park
- Bartow
- Bayboro
- Crystal River
- DeBary
- Higgins
- Hines
- Intercession City
- Rio Pinar
- Suwannee
- Tiger Bay
- Turner
- University of Florida Cogeneration

Anclote

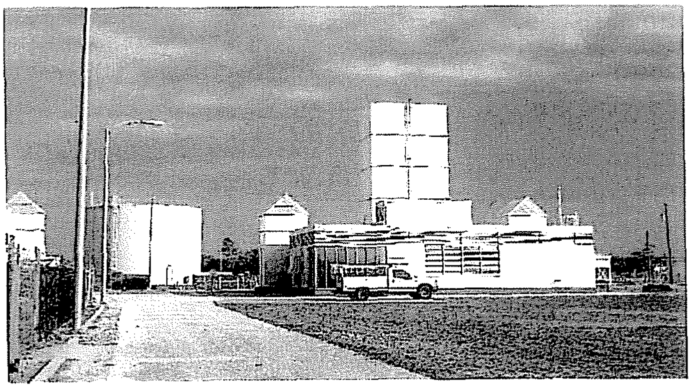


Details The Anclote Plant is a two-unit oil-fired steam plant located at the mouth of the Anclote River, one mile west of Tarpon Springs, Fla. Anclote's first unit began commercial service in 1974, and its second unit followed in 1978.

Location Holiday, Fla.

Capacity 1,011 MW steam

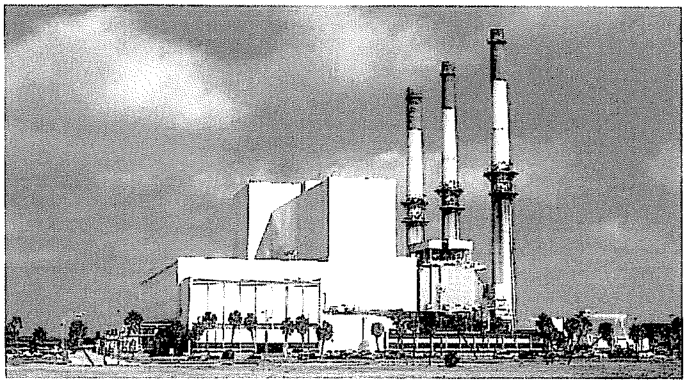
Avon Park



Details The Avon Park Plant, located near Avon Park, Fla., contains two combustion turbine units and is used during times of peak demand. The plant began operation in 1968.

Location Avon Park, Fla.

Capacity 48 MW combustion turbine



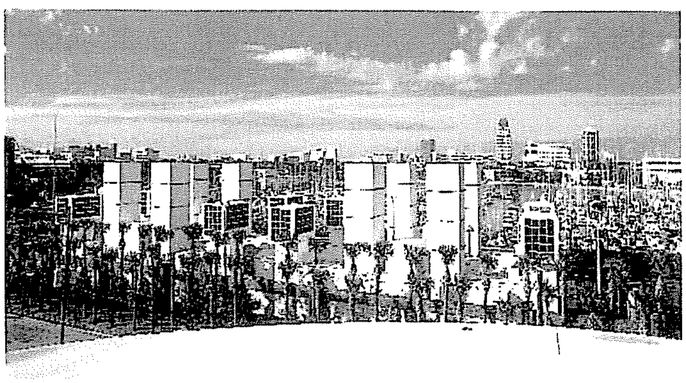
Bartow

Details Located on the west shore of Tampa Bay, Fla., the Bartow Plant is comprised of a four-on-one combined cycle unit, with four gas turbines and one steam turbine, which began operation in 2009, and four combustion turbine units, which began operation in 1972.

Location St. Petersburg, Fla.

Capacity 1,133 MW combined cycle

178 MW combustion turbine



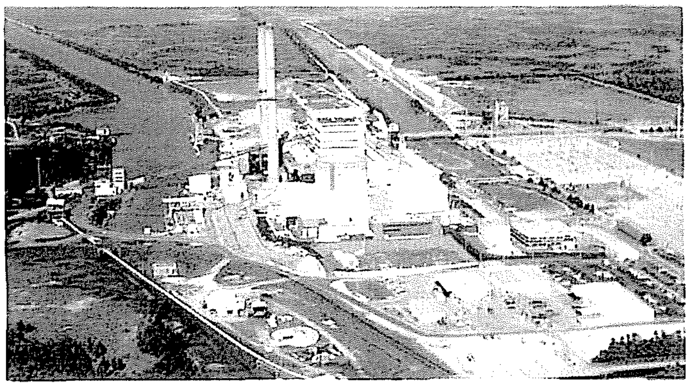
Bayboro

Details Located near St. Petersburg, Fla., the Bayboro Plant began operation in 1973 and has four combustion turbine units used during times of peak demand.

Location St. Petersburg, Fla.

Capacity 174 MW combustion turbine

Crystal River



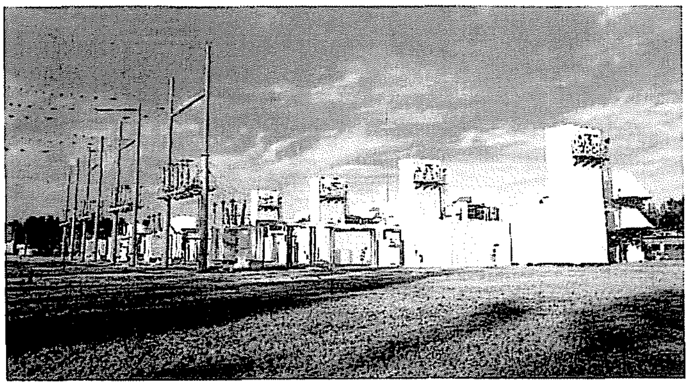
Details The Crystal River Complex consists of one PWR nuclear unit and four coal-fired generating units. These units came online in 1966, 1969, 1977, 1982 and 1984. Located about eight miles north of the town of Crystal River, Fla., the Crystal River Energy Complex is the largest generating plant on the Progress Energy system and one of the largest generating plants in the nation, with a total capacity of approximately 3,127 MW.

Location Crystal River, Fla.

Capacity 2,267 MW steam

860 MW nuclear

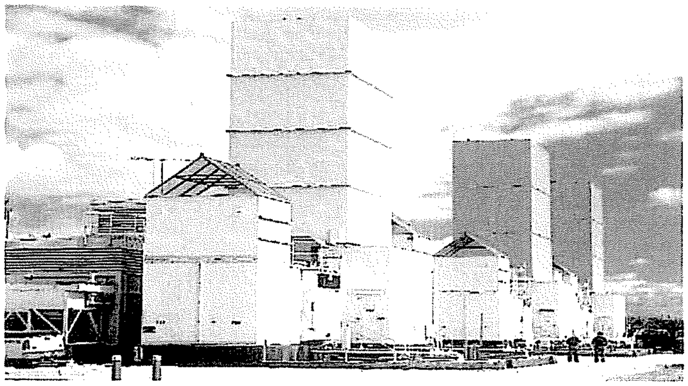
DeBary



Details The DeBary Plant, located near the town of DeBary, Fla., contains 10 combustion turbine units used primarily during times of peak demand. The plant began operation in 1975 with two units and additional units were added in 1976 and 1992.

Location DeBary, Fla.

Capacity 642 MW combustion turbine

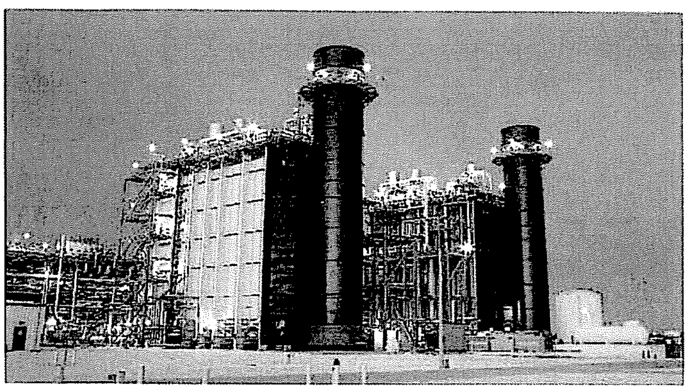


Higgins

Details The Higgins Plant, located near Oldsmar, Fla., has four combustion turbine units. Two units began commercial operation in 1969, and two additional units were added in 1970 and 1971.

Location Oldsmar, Fla.

Capacity 114 MW combustion turbine



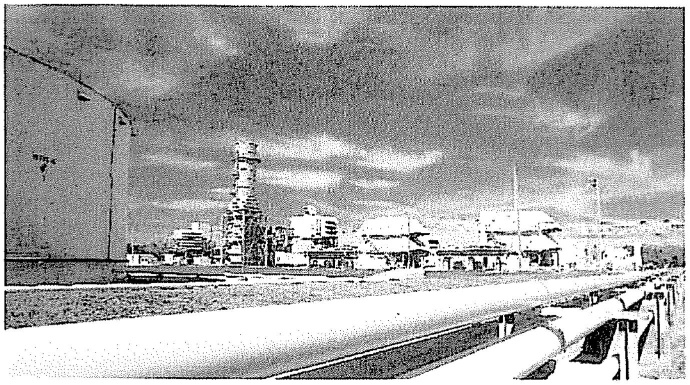
Hines

Details The Hines Plant, located near the town of Bartow, Fla., has four combined cycle units. The first unit began commercial operation in 1999 and subsequent units began operation in 2003, 2005 and 2007.

Location Bartow, Fla.

Capacity 1,912 MW combined cycle

Intercession City

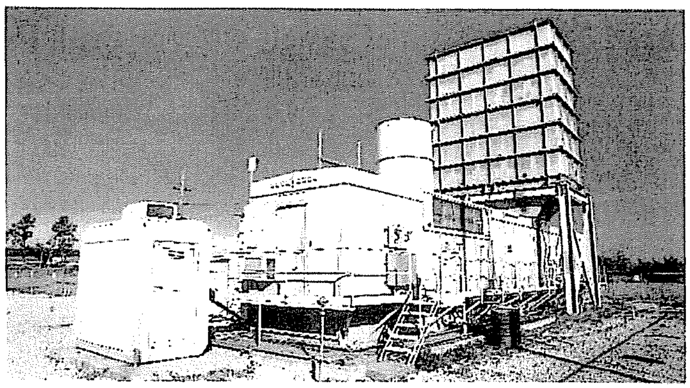


Details The Intercession City Plant contains 14 combustion turbine units used during times of peak demand. The plant is located near Intercession City, Fla. The first six units began operation in 1974, with additional units added in 1993, 1997 and 2000.

Location Intercession City, Fla

Capacity 980 MW combustion turbine

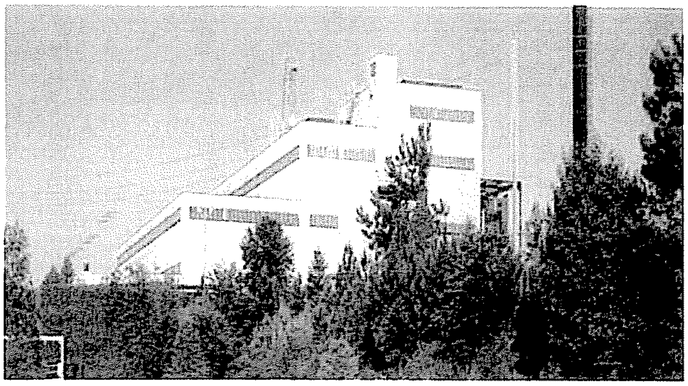
Rio Pinar



Details Progress Energy's Rio Pinar Plant, located near Rio Pinar, Fla., has a single combustion turbine unit, which began operation in 1970.

Location Rio Pinar, Fla.

Capacity 12 MW combustion turbine



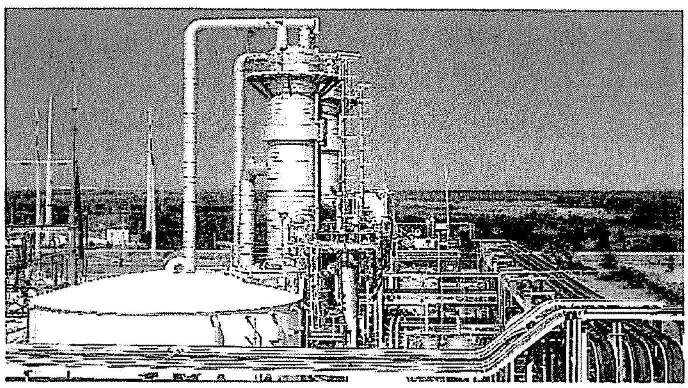
Suwannee

Details The Suwannee Plant, located on the banks of the Suwannee River near Live Oak, Fla., contains three oil-fired steam units that began operation in 1953, 1954 and 1956, and three combustion turbine units that went into service in 1980.

Location Live Oak, Fla.

Capacity 153 MW combustion turbine

131 MW steam



Tiger Bay

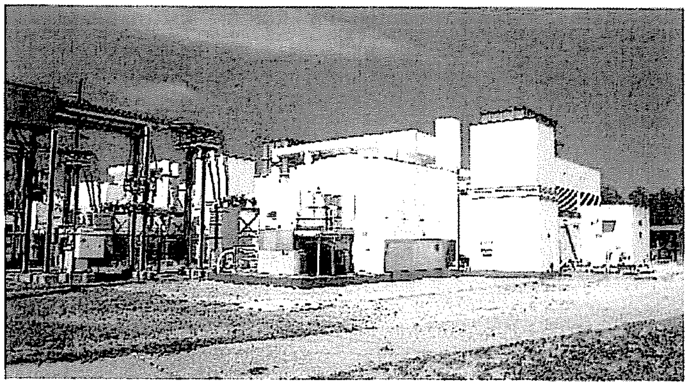
Details Located near Fort Meade, Fla., the Tiger Bay Plant contains one combined-cycle unit. The site is just six miles from the Hines Plant and began commercial operation in 1994. The plant was purchased from Destec in 1997.

Location Ft Meade, Fla.

Capacity 205 MW combined cycle

Florida

Turner

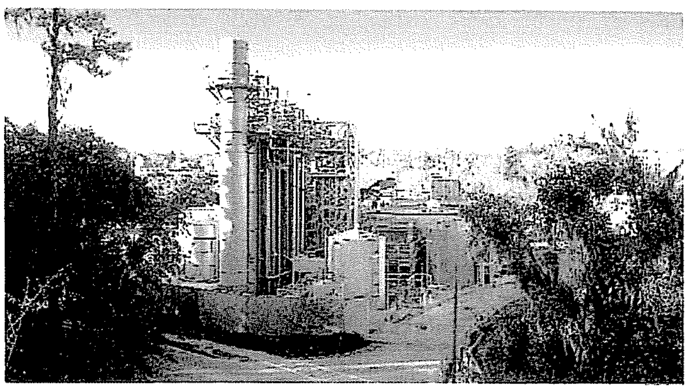


Details The Turner Plant is located near Enterprise, Fla., and consists of four combustion turbine units used during times of peak demand. The first two units began operation in 1970, with additional units added in 1974.

Location Enterprise, Fla.

Capacity 147 MW combustion turbine

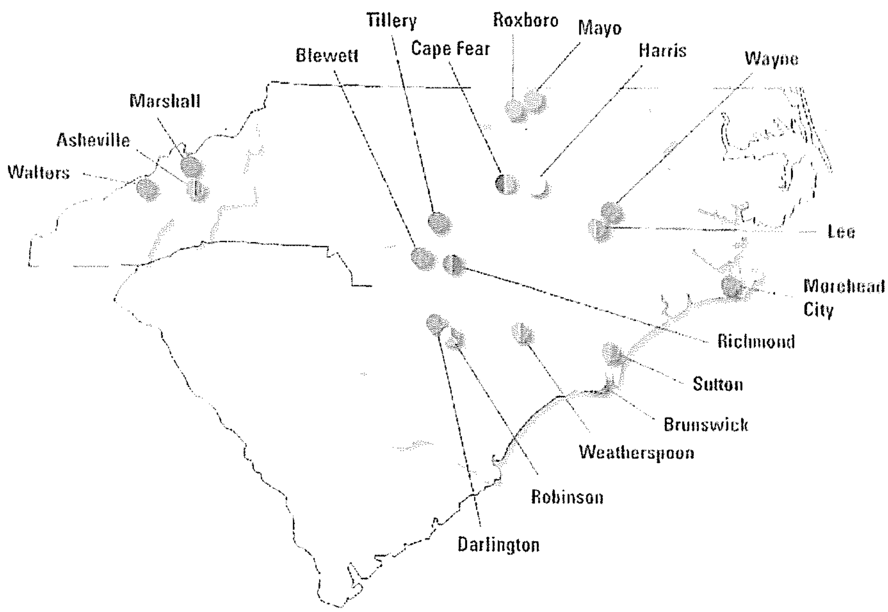
University of Florida Cogeneration



Details Located on the University of Florida at Gainesville campus, the University of Florida Cogeneration Plant houses one combustion turbine unit. The plant began commercial operation in 1994.

Location Gainesville, Fla.

Capacity 46 MW combustion turbine



Hydroelectric
Steam (coal, oil)
Combustion Turbine
Combined Cycle
Nuclear

Progress Energy Regulated Service Area

North Carolina
South Carolina

Asheville

Blewett

Brunswick

Cape Fear

Darlington (S.C.)

Harris

Lee

Marshall

Mayo

Morehead City

Richmond

Robinson (S.C.)

Roxboro

Sutton

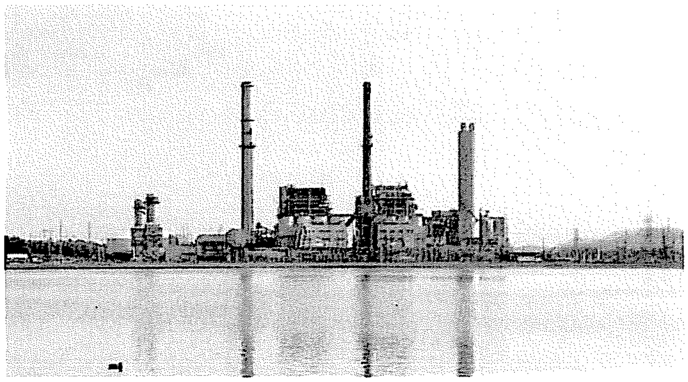
Tillery

Walters

Wayne

Weatherspoon

Asheville



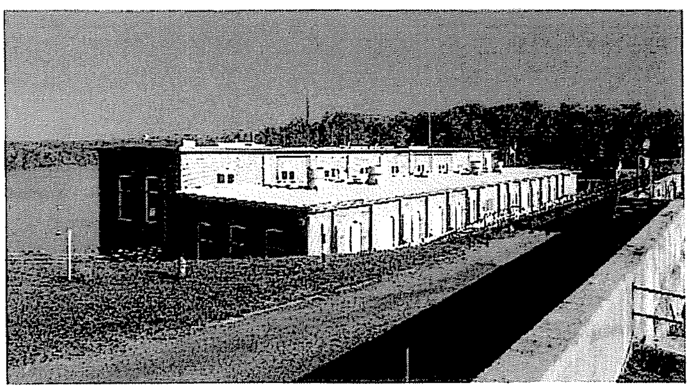
Details The Asheville Plant is the largest electric generating facility in Western North Carolina. Located near Skyland, N.C., the plant consists of two coal-fired units and two combustion turbine units. The Asheville Plant began commercial operation in 1964, with additions in 1971, 1999 and 2000.

Location Arden, N.C.

Capacity 376 MW steam

324 MW combustion turbine

Blewett



Details The Blewett Plant consists of four combustion turbine units as well as six hydroelectric generating units. The plant began commercial operation in 1912, with additions in 1971.

Location Lilesville, N.C

Capacity 52 MW combustion turbine

22 MW hydroelectric

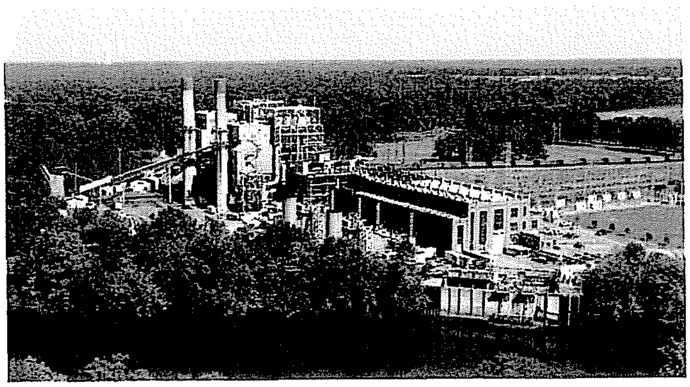
Brunswick

Details The Brunswick Plant houses two boiling water nuclear reactors. It was the first nuclear power plant built in North Carolina, beginning operation in 1975, with an additional unit in 1977. The plant and its nearby visitors center are located approximately two miles north of Southport, N.C.

Location Southport, N.C.

Capacity 1,858 MW nuclear

Cape Fear



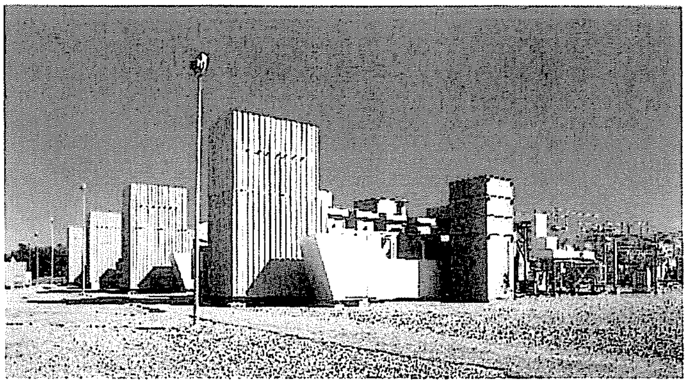
Details The Cape Fear Plant is located near Moncure, N.C., and began commercial operation in 1923 as the company's first coal-fired facility. Additional units came into service in 1924, 1956, 1958 and 1969. Today, the plant consists of two coal-fired units and two combined cycle generating units.

Location Moncure, N.C.

Capacity 316 MW steam

66 MW combined cycle

Darlington

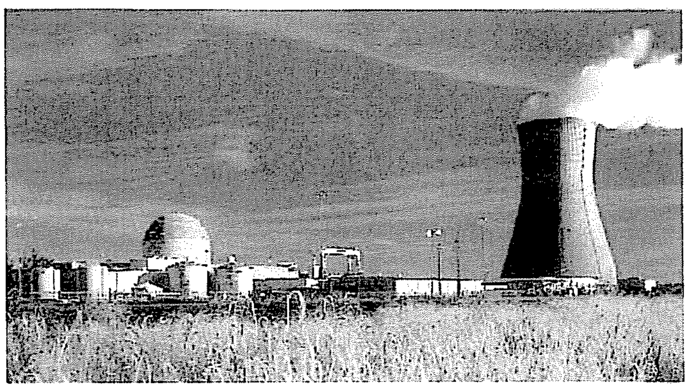


Details Located in South Carolina near Progress Energy's Robinson Plant, the Darlington Plant consists of 13 combustion turbine units. The plant began operation in 1974, with additions in 1975 and 1997.

Location Hartsville, S.C.

Capacity 799 MW combustion turbine

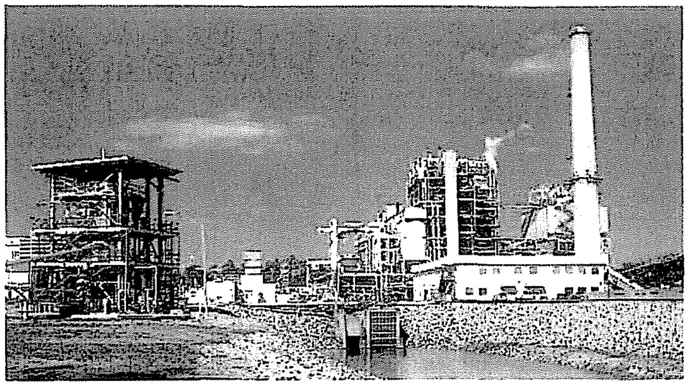
Harris



Details The Harris Nuclear Plant is a single-unit pressurized water reactor. This plant was the last U.S. nuclear plant to receive a construction permit and began commercial operation May 1987. The Harris Nuclear Plant and its nearby visitors center are located approximately 25 miles southwest of Raleigh, N.C.

Location New Hill, N.C

Capacity 900 MW nuclear



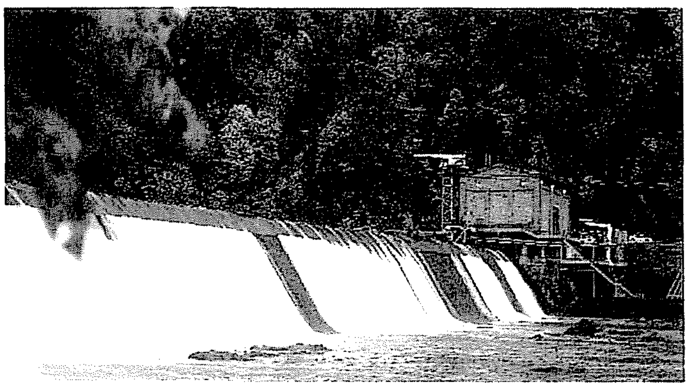
Lee

Details The Lee Plant, part of the H.F. Lee Energy Complex, is located on the Neuse River near Goldsboro, N.C., and contains three coal-fired steam units and four combustion turbine units. The plant began operation in 1951, with additions in 1952, 1962, 1968 and 1971.

Location Goldsboro, N.C.

Capacity 397 MW steam

75 MW combustion turbine



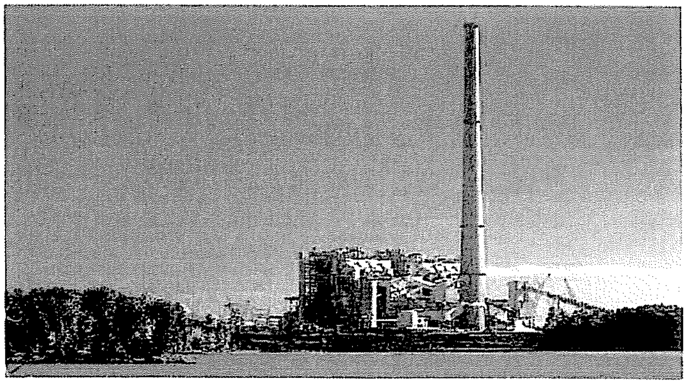
Marshall

Details The Marshall Plant is located on the French Broad River, northwest of Asheville. Its two hydroelectric generating units produce approximately 4 megawatts, using a concrete masonry gravity dam standing 36 feet high. The Marshall Plant began commercial operation in 1910.

Location Marshall, N.C.

Capacity 4 MW hydroelectric

Mayo

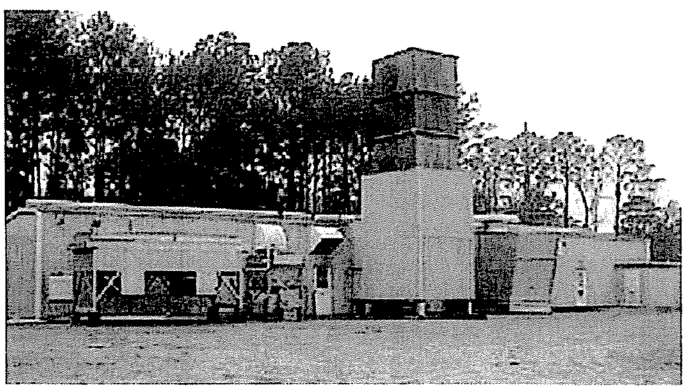


Details Located near Roxboro, N.C., the Mayo Plant began commercial operation in 1983 and is a dual-boiler unit and coal-fired facility.

Location Roxboro, N.C.

Capacity 727 MW steam

Morehead City

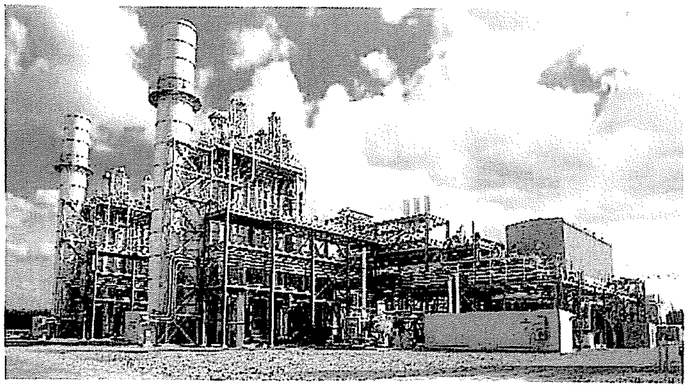


Details The Morehead City Plant is located near Morehead City, N.C. It has one combustion turbine unit used during times of peak demand. Plant operation began in 1968.

Location Morehead City, N.C

Capacity 12 MW combustion turbine

Richmond



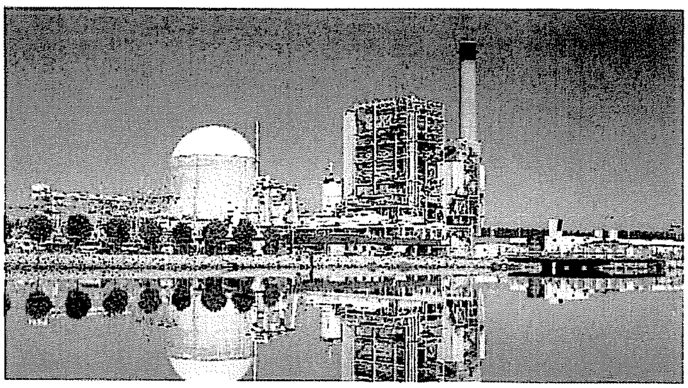
Details The Richmond Plant houses five combustion turbine units and one combined-cycle unit. The plant is located just south of Hamlet, N.C., and began commercial operation in 2001, with additions in 2002. A 600-MW combined cycle unit is under construction at the site and will come online in 2011.

Location Hamlet, N C.

Capacity 820 MW combustion turbine

470 MW combined cycle

Robinson



Details The Robinson Plant houses one coal-fired steam unit, one combustion turbine unit and one pressurized water nuclear unit in its location near Hartsville, S.C. The coal-fired unit began commercial operation in 1960, the combustion turbine unit began operation in 1968, while the nuclear unit began operation in 1971.

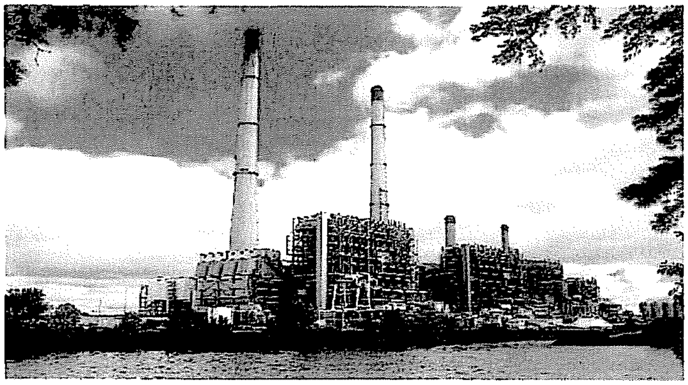
Location Hartsville, S.C.

Capacity 724 MW nuclear

177 MW steam

15 MW combustion turbine

Roxboro

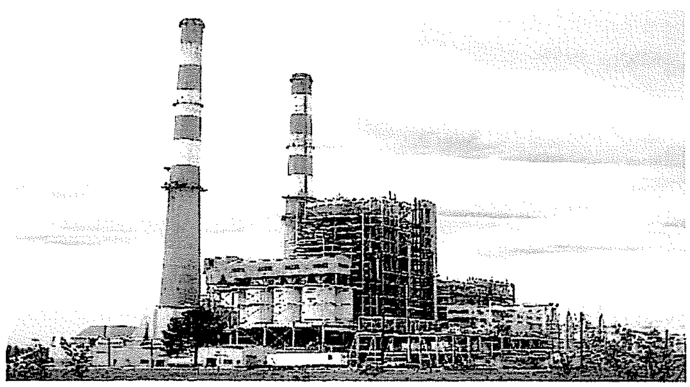


Details The Roxboro Plant is one of Progress Energy's largest plants and ranks as one of the largest power plants in the United States. The plant contains four coal-fired steam units. Operation began in 1966 with additions in 1973 and 1980.

Location Semora, N.C.

Capacity 2,422 MW steam

Sutton



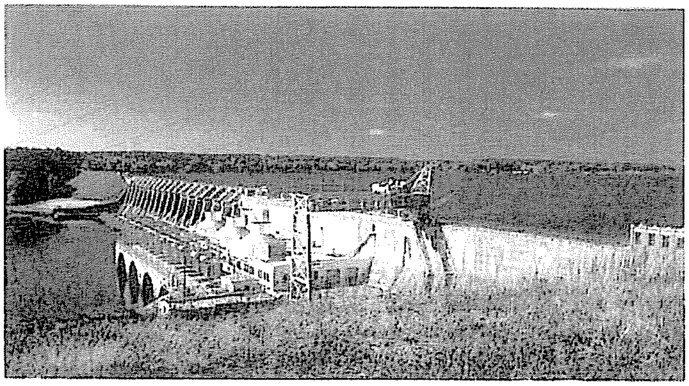
Details Located near Wilmington, N.C., the Sutton Plant consists of three coal-fired steam units. The first unit began commercial operation in 1954, with additions in 1955 and 1972. The plant also contains three combustion turbine units that began operation in 1968 and 1969.

Location Wilmington, N.C.

Capacity 604 MW steam

61 MW combustion turbine

Tillery

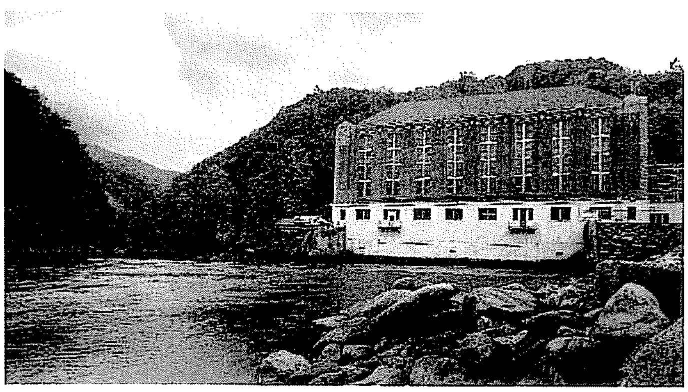


Details The Tillery Plant is located on the Pee Dee River near Mt. Gilead, N.C. The plant features an impressive dam, 2,800 feet long and 86 feet high, as well as flood-control gates. The Tillery Plant began commercial operation in 1928, with additions in 1960.

Location Mt. Gilead, N.C.

Capacity 87 MW hydroelectric

Walters

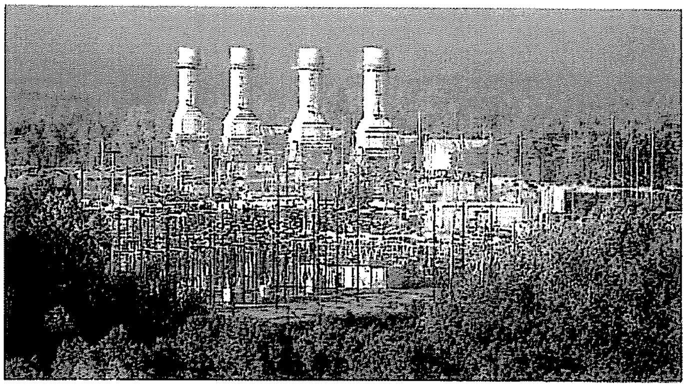


Details The Walters Plant is located on the Pigeon River near the North Carolina-Tennessee border. Twelve miles upstream from the hydroelectric plant is the arch-shaped Walters Dam, which is 185 feet high. The plant began commercial operation in 1930.

Location Waterville, N.C.

Capacity 112 MW hydroelectric

Wayne

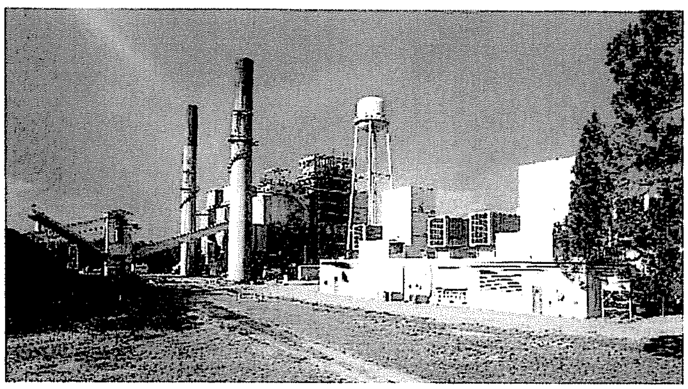


Details The Wayne County Plant, part of the H.F. Lee Energy Complex, consists of five combustion turbine units. The plant began operation in 2000 with an addition in 2009.

Location Goldsboro, N.C.

Capacity 863 MW combustion turbine

Weatherspoon



Details The Weatherspoon Plant, located near Lumberton, N.C., includes three coal-fired steam units. The first unit began operation in 1949 with additions in 1950 and 1952. In addition, this site has four combustion turbine units that began commercial operation in 1970 and 1971.

Location Lumberton, N.C.

Capacity 171 MW steam

131 MW combustion turbine

Updated March 2010. Ratings reflect compliance with NERC Reliability Standards (2006) and include Progress Energy's co-ownership interests.

Progress Energy

EXECUTION COPY

AGREEMENT AND PLAN OF MERGER

by and among

DUKE ENERGY CORPORATION,

DIAMOND ACQUISITION CORPORATION

and

PROGRESS ENERGY, INC.

Dated as of January 8, 2011

TABLE OF CONTENTS

DEFINED TERMS INDEX

AGREEMENT AND PLAN OF MERGER, dated as of January 8, 2011 (this "Agreement"), by and among DUKE ENERGY CORPORATION, a Delaware corporation ("Duke"), DIAMOND ACQUISITION CORPORATION, a North Carolina corporation and a direct wholly-owned subsidiary of Duke ("Merger Sub"), and PROGRESS ENERGY, INC., a North Carolina corporation ("Progress").

WHEREAS, the respective Boards of Directors of Duke and Merger Sub have approved this Agreement, and deem it advisable and in the best interests of their respective stockholders to consummate the merger of Merger Sub with and into Progress on the terms and conditions set forth herein (the "Merger"), and the Board of Directors of Duke has determined to recommend to the stockholders of Duke that they approve an amendment to the Amended and Restated Certificate of Incorporation of Duke providing for a reverse stock split and that they approve the issuance of shares of Duke Common Stock in connection with the Merger as set forth in this Agreement;

WHEREAS, the Board of Directors of Progress has adopted this Agreement, and deems it in the best interest of Progress to consummate the merger of Merger Sub with and into Progress on the terms and conditions set forth herein and has determined to recommend to the shareholders of Progress that they approve this Agreement and the Merger;

WHEREAS, Duke and Progress desire to make certain representations, warranties, covenants and agreements in connection with the Merger and the transactions contemplated by this Agreement and also to prescribe various conditions to the Merger; and

WHEREAS, for United States federal income tax purposes, it is intended that the Merger shall qualify as a reorganization under Section 368(a) of the Internal Revenue Code of 1986, as amended (the "Code"), and this Agreement is intended to be, and is hereby, adopted as a plan of reorganization within the meaning of Section 368(a) of the Code.

NOW, THEREFORE, in consideration of the foregoing and of the representations, warranties, covenants and agreements contained in this Agreement, the parties agree as follows:

ARTICLE I

THE MERGER

Section 1.01. The Merger. Upon the terms and subject to the conditions set forth in this Agreement, at the Effective Time, Merger Sub shall be merged with and into Progress in accordance with the North Carolina Business Corporation Act (the "NCBCA"). At the Effective Time, the separate corporate existence of Merger Sub shall cease, and Progress shall be the surviving corporation in the Merger (the "Surviving Corporation") and shall continue its corporate existence under the laws of the State of North Carolina and shall succeed to and assume all of the rights and obligations of Progress and Merger Sub in accordance with the NCBCA and shall become, as a result of the Merger, a direct wholly-owned subsidiary of Duke.

Section 1.02. Closing. Unless this Agreement shall have been terminated pursuant to Section 7.01, the closing of the Merger (the "Closing") will take place at 10:00 a.m., local time, on a date to be specified by the parties (the "Closing Date"), which, subject to Section 4.06 of this Agreement, shall be no later than the second business day after satisfaction or waiver of the conditions set forth in Article VI (other than those conditions that by their terms are to be satisfied at the Closing, but subject to the satisfaction or waiver (to the extent permitted by applicable law) of such conditions at such time), unless another time or date is agreed to by the parties hereto. The Closing shall be held at such location as is agreed to by the parties hereto.

Section 1.03. Effective Time of the Merger. Subject to the provisions of this Agreement, as soon as practicable after 10:00 a.m., local time, on the Closing Date the parties thereto shall file articles of merger (the "Articles of Merger") executed in accordance with, and containing such information as is required by, Section 55-11-05 of the NCBCA with the Secretary of State of the State of North Carolina and on or after the Closing Date shall make all other filings or recordings required under the NCBCA. The Merger shall become effective at such time as the Articles of Merger are duly filed with the Secretary of State of the State of North Carolina or at such later time as is specified in the Articles of Merger (the time the Merger becomes effective being hereinafter referred to as the "Effective Time").

Section 1.04. Effects of the Merger. The Merger shall generally have the effects set forth in this Agreement and the applicable provisions of the NCBCA.

Section 1.05. Articles of Incorporation and By-laws of the Surviving Corporation.

(a) At the Effective Time, the articles of incorporation of Merger Sub as in effect immediately prior to the Effective Time shall be the articles of incorporation of the Surviving Corporation until thereafter amended in accordance with the provisions thereof and hereof and applicable Law, in each case consistent with the obligations set forth in Section 5.08.

(b) At the Effective Time, the by-laws of Merger Sub as in effect immediately prior to the Effective Time shall be the by-laws of the Surviving Corporation until thereafter amended in accordance with the provisions thereof and hereof and applicable Law, in each case consistent with the obligations set forth in Section 5.08.

Section 1.06. Directors and Officers of the Surviving Corporation.

(a) The directors of Merger Sub at the Effective Time shall, from and after the Effective Time, be the directors of the Surviving Corporation in the Merger until their successors have been duly elected or appointed and qualified, or their earlier death, resignation or removal.

(b) The officers of Progress at the Effective Time shall, from and after the Effective Time, be the initial officers of the Surviving Corporation until their successors have been duly elected or appointed and qualified, or their earlier death, resignation or removal.

Section 1.07. Post-Merger Operations.

(a) Board Matters. Duke shall take all necessary corporate action to cause the following to occur as of the Effective Time: (i) the number of directors constituting the Board of Directors of Duke shall be as set forth in **Exhibit A** hereto, with the identities of the Duke Designees (as defined in **Exhibit A** hereto) as set forth in **Exhibit A** hereto and the identities of the Progress Designees (as defined in **Exhibit A** hereto) as identified by Progress after the date hereof in accordance with the provisions of **Exhibit A** hereto, subject to such individuals' ability and willingness to serve; (ii) the committees of the Board of Directors of Duke shall be as set forth in **Exhibit A** hereto, and the chairpersons of each such committee shall be designated in accordance with the provisions of **Exhibit A** hereto, subject to such individuals' ability and willingness to serve; and (iii) the lead independent director of the Board of Directors of Duke shall be designated in accordance with the provisions of **Exhibit A** hereto, subject to such individual's ability and willingness to serve. In the event any Duke Designee or any Progress Designee becomes unable or unwilling to serve as a director on the Board of Directors of Duke, or as a chairperson of a committee or as lead independent director, a replacement for such designee shall be determined in accordance with the provisions of **Exhibit A** hereto.

(b) Chairman of the Board; President and Chief Executive Officer; Executive Officers.

(i) Duke's Board of Directors shall cause the current Chief Executive Officer of Progress (the "Progress CEO") to be appointed as the President and Chief Executive Officer of Duke, and cause the current Chief Executive Officer of Duke (the "Duke CEO") to be appointed as the Chairman of the Board of Directors of Duke, in each case, effective as of, and conditioned upon the occurrence of, the Effective Time, and subject to such individuals' ability and willingness to serve. The roles and responsibilities of such officers shall be as specified on **Exhibit B** to this Agreement. In the event that the Progress CEO is unwilling or unable to serve as the President and Chief Executive Officer of Duke as of the Effective Time, Progress and Duke shall confer and mutually designate a President and Chief Executive Officer of Duke, who shall be appointed by Duke in accordance with the Amended and Restated Certificate of Incorporation and Amended and Restated By-laws of Duke as in effect as of the Effective Time. In the event that the Duke CEO is unwilling or unable to serve as the Chairman of the Board of Directors of Duke as of the Effective Time, Progress and Duke shall confer and mutually designate a Chairman of the Board of Directors of Duke, who shall be appointed by Duke in accordance with the Amended and Restated Certificate of Incorporation and Amended and Restated By-laws of Duke as in effect as of the Effective Time.

(ii) The material terms of the Progress CEO's employment with Duke as the President and Chief Executive Officer of Duke to be in effect as of the Effective Time are set forth on **Exhibit C** hereto. The parties shall use their commercially reasonable efforts to cause an employment agreement reflecting such terms to be executed by Duke and the Progress CEO as promptly as practicable after the date hereof, effective as of, and conditioned upon the occurrence of, the Effective Time.

(iii) The material terms of the Duke CEO's employment with Duke as the Chairman of the Board of Directors of Duke to be in effect as of the Effective Time are set forth on **Exhibit D** hereto. The parties shall use their commercially reasonable efforts to cause an amendment to the employment agreement of the Duke CEO reflecting such amended terms to be executed by Duke and the Duke CEO as promptly as practicable after the date hereof, effective as of, and conditioned upon the occurrence of, the Effective Time.

(iv) Subject to such individuals' ability and willingness to so serve, Duke shall take all necessary corporate action so that the individuals identified on **Exhibit E** and designated for the Duke senior executive officer positions specified on such Exhibit shall hold such officer positions as of the Effective Time. In the event that any such individual(s) is(are) unwilling or unable to serve in such officer position(s) as of the Effective Time, Progress and Duke shall confer and mutually appoint other individual(s) to serve in such officer position(s).

(c) Name, Headquarters and Operations. Following the Effective Time, Duke shall retain its current name, and shall maintain its headquarters and principal corporate offices in Charlotte, North Carolina, none of which shall change as a result of the Merger, and, taken together with its subsidiaries following the Effective Time, shall maintain substantial operations in Raleigh, North Carolina.

(d) Community Support. The parties agree that provision of charitable contributions and community support in their respective service areas serves a number of their important corporate goals. During the two-year period immediately following the Effective Time, Duke and its subsidiaries taken as a whole intend to continue to provide charitable contributions and community support within the service areas of the parties and each of their respective subsidiaries in each service area at levels substantially comparable to the levels of charitable contributions and community support provided, directly or indirectly, by Duke and Progress within their respective service areas prior to the Effective Time.

Section 1.08. Transition Committee. As promptly as practicable after the date hereof and to the extent permitted by applicable law, the parties shall create a special transition committee to oversee integration planning, including, to the extent permitted by applicable law, consulting with respect to operations and major regulatory decisions. This transition committee shall be co-chaired by the Progress CEO and the Duke CEO, and shall be composed of such chief executive officers and two other designees of Duke and two other designees of Progress.

ARTICLE II

CONVERSION OF SHARES; EXCHANGE OF CERTIFICATES

Section 2.01 Effect on Capital Stock. At the Effective Time, by virtue of the Merger and without any action on the part of holders of any shares of Progress Common Stock or any capital stock of Merger Sub:

(a) Cancellation of Certain Progress Common Stock. Each share of Progress Common Stock that is owned by Progress (other than in a fiduciary capacity), Duke or Merger Sub shall automatically be canceled and retired and shall cease to exist, and no consideration shall be delivered in exchange therefor.

(b) Conversion of Progress Common Stock. Subject to Sections 2.02(e) and 2.02(k), each issued and outstanding share of Progress Common Stock (other than shares to be canceled in accordance with Section 2.01(a)) shall be converted into the right to receive 2.6125 (the "Exchange Ratio") fully paid and nonassessable shares of Duke Common Stock (such aggregate amount, the "Merger Consideration"). As of the Effective Time, all such shares of Progress Common Stock shall no longer be outstanding and shall automatically be canceled and retired and shall cease to exist, and each holder of a certificate representing any such shares of Progress Common Stock shall cease to have any rights with respect thereto, except the right to receive the Merger Consideration as contemplated by this Section 2.01(b) (and cash in lieu of fractional shares of Duke Common Stock payable in accordance with Section 2.02(e)) to be issued or paid in consideration therefor upon the surrender of certificates in accordance with Section 2.02, without interest, and the right to receive dividends and other distributions in accordance with Section 2.02.

(c) Conversion of Merger Sub Common Stock. At the Effective Time, by virtue of the Merger and without any action on the part of the holder thereof, each share of common stock, par value $0.01 per share, of Merger Sub issued and outstanding immediately prior to the Effective Time shall be converted into and become one validly issued, fully paid and nonassessable share of common stock, par value $0.01 per share, of the Surviving Corporation and shall constitute the only outstanding capital stock of the Surviving Corporation. From and after the Effective Time, all certificates representing the common stock of Merger Sub shall be deemed for all purposes to represent the number of shares of common stock of the Surviving Corporation into which they were converted in accordance with the immediately preceding sentence.

Section 2.02 Exchange of Certificates.

(a) Exchange Agent. Prior to the Effective Time, Duke shall enter into an agreement with such bank or trust company as may be mutually agreed by Duke and Progress (the "Exchange Agent"), which agreement shall provide that Duke shall deposit with the Exchange Agent at or prior to the Effective Time, for the benefit of the holders of shares of Progress Common Stock, for exchange in accordance with this Article II, through the Exchange Agent, certificates representing the shares of Duke Common Stock representing the Merger Consideration (or appropriate alternative arrangements shall be made by Duke if uncertificated shares of Duke Common Stock will be issued). Following the Effective Time, Duke shall make available to the Exchange Agent, from time to time as needed, cash sufficient to pay any dividends and other distributions pursuant to Section 2.02(c) (such shares of Duke Common Stock to be deposited, together with any dividends or distributions with respect thereto with a record date after the Effective Time, being hereinafter referred to as the "Exchange Fund").

(b) Exchange Procedures. As soon as reasonably practicable after the Effective Time and in any event not later than the fifth Business Day following the Effective Time, Duke shall cause the Exchange Agent to mail to each holder of record of a certificate or certificates that immediately prior to the Effective Time represented outstanding shares of Progress Common Stock (the "Certificates") whose shares were converted into the right to receive shares of Duke Common Stock pursuant to Section 2.01(b), (i) a letter of transmittal (which shall specify that delivery shall be effected, and risk of loss and title to the Certificates shall pass, only upon delivery of the Certificates to the Exchange Agent and shall be in such form and have such other provisions as Duke and Progress may reasonably specify) and (ii) instructions for use in surrendering the Certificates in exchange for certificates representing whole shares of Duke Common Stock (or appropriate alternative arrangements shall be made by Duke if uncertificated shares of Duke Common Stock will be issued), cash in lieu of fractional shares pursuant to Section 2.02(e) and any dividends or other distributions payable pursuant to Section 2.02(c). Upon surrender of a Certificate for cancellation to the Exchange Agent, together with such letter of transmittal, duly completed and validly executed in accordance with the instructions thereto, and such other documents as may reasonably be required by the Exchange Agent, the holder of such Certificate shall be entitled to receive in exchange therefor that number of whole shares of Duke Common Stock (which shall be in uncertificated book entry form unless a physical certificate is requested), that such holder has the right to receive pursuant to the provisions of this Article II, certain dividends or other distributions in accordance with Section 2.02(c) and cash in lieu of any fractional share of Duke Common Stock in accordance with Section 2.02(e), and the Certificate so surrendered shall forthwith be canceled. In the event of a transfer of ownership of Progress Common Stock that is not registered in the transfer records of Progress, the proper number of shares of Duke Common Stock may be issued to a person other than the person in whose name the Certificate so surrendered is registered if such Certificate shall be properly endorsed or otherwise be in proper form for transfer and the person requesting such issuance shall pay any transfer or other taxes required by reason of the issuance of shares of Duke Common Stock to a person other than the registered holder of such Certificate or establish to the satisfaction of Duke that such tax has been paid or is not applicable. Until surrendered as contemplated by this Section 2.02, each Certificate shall be deemed at any time after the Effective Time to represent only the right to receive upon such surrender the Merger Consideration, which the holder thereof has the right to receive in respect of such Certificate pursuant to the provisions of this Article II, certain dividends or other distributions in accordance with Section 2.02(c) and cash in lieu of any fractional share of Duke Common Stock, in accordance with Section 2.02(e). No interest shall be paid or will accrue on the Merger Consideration or any cash payable to holders of Certificates pursuant to the provisions of this Article II.

(c) Distributions with Respect to Unexchanged Shares. No dividends or other distributions with respect to Duke Common Stock with a record date after the Effective Time shall be paid to the holder of any unsurrendered Certificate with respect to the shares of Duke Common Stock issuable hereunder in respect thereof and no cash payment in lieu of fractional shares shall be paid to any such holder pursuant to Section 2.02(e), and all such dividends and other distributions shall be paid by Duke to the Exchange Agent and shall be included in the Exchange Fund, in each case until the surrender of such Certificate in accordance with this Article II. Subject to the effect of applicable escheat or similar laws, following surrender of any such Certificate there shall be paid to the recordholder thereof, (i) without interest, the number of whole shares of Duke Common Stock issuable in exchange therefor pursuant to this Article II, the amount of dividends or other distributions with a record date after the Effective Time theretofore paid with respect to such whole shares of Duke Common Stock and the amount of any cash payable in lieu of a fractional share of Duke Common Stock to which such holder is entitled pursuant to Section 2.02(e) and (ii) at the appropriate payment date, the amount of dividends or other distributions with a record date after the Effective Time but prior to such surrender and with a payment date subsequent to such surrender payable with respect to such whole shares of Duke Common Stock.

(d) No Further Ownership Rights in Progress Common Stock; Closing of Transfer Books. All shares of Duke Common Stock issued upon the surrender for exchange of Certificates in accordance with the terms of this Article II (including any cash paid pursuant to this Article II) shall be deemed to have been issued (and paid) in full satisfaction of all rights pertaining to the shares of Progress Common Stock theretofore represented by such Certificates, subject, however, to Progress's obligation to pay any dividends or make any other distributions with a record date prior to the Effective Time that may have been declared or made by Progress on such shares of Progress Common Stock that remain unpaid at the Effective Time. As of the Effective Time, the stock transfer books of Progress shall be closed, and there shall be no further registration of transfers on the stock transfer books of Progress of the shares of Progress Common Stock that were outstanding immediately prior to the Effective Time. If, after the Effective Time, Certificates are presented to Progress, Duke or the Exchange Agent for any reason, they shall be canceled and exchanged as provided in this Article II, except as otherwise required by law.

(e) No Fractional Shares.

(i) No certificates or scrip representing fractional shares of Duke Common Stock shall be issued upon the surrender for exchange of Certificates, no dividend or distribution of Duke shall relate to such fractional share interests and such fractional share interests will not entitle the owner thereof to vote or to any rights of a shareholder of Duke but, in lieu thereof, each holder of such Certificate will be entitled to a cash payment in accordance with the provisions of this Section 2.02(e).

(ii) As promptly as practicable following the Effective Time, the Exchange Agent shall determine the excess of (A) the number of whole shares of Duke Common Stock delivered to the Exchange Agent by Duke pursuant to Section 2.02(a) representing the Merger Consideration over (B) the aggregate number of whole shares of Duke Common Stock to be distributed to former holders of Progress Common Stock pursuant to Section 2.02(b) (such excess being herein called the "Excess Shares"). Following the Effective Time, the Exchange Agent shall, on behalf of former shareholders of Progress, sell the Excess Shares at then-prevailing prices on the New York Stock Exchange, Inc. ("NYSE"), all in the manner provided in Section 2.02(e)(iii). The parties acknowledge that payment of the cash consideration in lieu of issuing fractional shares of Duke Common Stock was not separately bargained for consideration but merely represents a mechanical rounding off for purposes of avoiding the expense and inconvenience to Duke that would otherwise be caused by the issuance of fractional shares of Duke Common Stock.

(iii) The sale of the Excess Shares by the Exchange Agent shall be executed on the NYSE through one or more member firms of the NYSE and shall be executed in round lots to the extent practicable. The Exchange Agent shall use reasonable efforts to complete the sale of the Excess Shares as promptly following the Effective Time as, in the Exchange Agent's sole judgment, is practicable consistent with obtaining the best execution of such sales in light of prevailing market conditions. Until the net proceeds of such sale or sales have been distributed to the holders of Certificates formerly representing Progress Common Stock, the Exchange Agent shall hold such proceeds in trust for holders of Progress Common Stock (the "Common Shares Trust"). The Surviving Corporation shall pay all commissions, transfer taxes and other out-of-pocket transaction costs, including the expenses and compensation of the Exchange Agent incurred in connection with such sale of the Excess Shares. The Exchange Agent shall determine the portion of the Common Shares Trust to which each former holder of Progress Common Stock is entitled, if any, by multiplying the amount of the aggregate net proceeds composing the Common Shares Trust by a fraction, the numerator of which is the amount of the fractional share interest to which such former holder of Progress Common Stock would otherwise be entitled (after taking into account all shares of Progress Common Stock held at the Effective Time by such holder) and the denominator of which is the aggregate amount of fractional share interests to which all former holders of Progress Common Stock would otherwise be entitled.

(iv) As soon as practicable after the determination of the amount of cash, if any, to be paid to holders of Certificates formerly representing Progress Common Stock with respect to any fractional share interests, the Exchange Agent shall make available such amounts to such holders of Certificates formerly representing Progress Common Stock, without interest, subject to and in accordance with the terms of Section 2.02(c).

(f) Termination of Exchange Fund. Any portion of the Exchange Fund that remains undistributed to the holders of the Certificates for one year after the Effective Time shall be delivered to Duke, upon demand, and any holders of the Certificates who have not theretofore complied with this Article II shall thereafter look only to Duke for payment of their claim for Merger Consideration, any dividends or distributions with respect to Duke Common Stock and any cash in lieu of fractional shares of Duke Common Stock.

(g) No Liability. None of Duke, Progress, Merger Sub, the Surviving Corporation or the Exchange Agent or any of their respective directors, officers, employees and agents shall be liable to any person in respect of any shares of Duke Common Stock, any dividends or distributions with respect thereto, any cash in lieu of fractional shares of Duke Common Stock or any cash from the Exchange Fund, in each case delivered to a public official pursuant to any applicable abandoned property, escheat or similar law. If any Certificate shall not have been surrendered prior to five years after the Effective Time (or immediately prior to such earlier date on which any Merger Consideration, any dividends or distributions payable to the holder of such Certificate or any cash payable to the holder of such Certificate formerly representing Progress Common Stock pursuant to this Article II, would otherwise escheat to or become the property of any Governmental Authority), any such Merger Consideration, dividends or distributions in respect of such Certificate or such cash shall, to the extent permitted by applicable law, become the property of Duke, free and clear of all claims or interest of any person previously entitled thereto.

(h) Investment of Exchange Fund. The Exchange Agent shall invest any cash included in the Exchange Fund, as directed by Duke, on a daily basis, provided that no gain or loss thereon shall affect the amounts payable to the holders of Progress Common Stock pursuant to the other provisions of this Article II. Any interest and other income resulting from such investments shall be paid to Duke.

(i) Withholding Rights. Duke and the Exchange Agent shall be entitled to deduct and withhold from any consideration payable pursuant to this Agreement to any person who was a holder of Progress Common Stock immediately prior to the Effective Time such amounts as Duke and the Exchange Agent may be required to deduct and withhold with respect to the making of such payment under the Code or any other provision of applicable federal, state, local or foreign tax law. To the extent that amounts are so withheld by Duke or the Exchange Agent and duly paid over to the applicable taxing authority, such withheld amounts shall be treated for all purposes of this Agreement as having been paid to the person to whom such consideration would otherwise have been paid.

(j) Lost, Stolen or Destroyed Certificates. If any Certificate shall have been lost, stolen or destroyed, upon the making of an affidavit of that fact by the person claiming such Certificate to be lost, stolen or destroyed and, if required by Duke, the posting by such person of a bond in such reasonable amount as Duke may direct as indemnity against any claim that may be made against it with respect to such Certificate, the Exchange Agent shall issue in exchange for such lost, stolen or destroyed Certificate, the Merger Consideration and, if applicable, any unpaid dividends and distributions on shares of Duke Common Stock deliverable in respect thereof and any cash in lieu of fractional shares, in each case pursuant to this Agreement.

(k) Adjustments to Prevent Dilution. In the event that Progress changes the number of shares of Progress Common Stock or securities convertible or exchangeable into or exercisable for shares of Progress Common Stock, or Duke changes the number of shares of Duke Common Stock or securities convertible or exchangeable into or exercisable for shares of Duke Common Stock, issued and outstanding prior to the Effective Time, in each case as a result of a reclassification, stock split (including a reverse stock split), stock dividend or distribution, subdivision, exchange or readjustment of shares, or other similar transaction, the Exchange Ratio shall be equitably adjusted; provided, however, that nothing in this Section 2.02(k) shall be deemed to permit or authorize any party hereto to effect any such change that it is not otherwise authorized or permitted to undertake pursuant to this Agreement. Without limiting the generality of the foregoing, upon Duke's implementation of the reverse stock split as described in Section 5.01(c), the Exchange Ratio will be reduced by multiplying the then-current Exchange Ratio by a ratio, the numerator of which is the number of shares of Duke Common Stock outstanding immediately following such reverse stock split, and the denominator of which is the number of shares of Duke Common Stock outstanding immediately prior to such reverse stock split.

(l) Uncertificated Shares. In the case of outstanding shares of Progress Common Stock that are not represented by Certificates, the parties shall make such adjustments to this Section 2.02 as are necessary or appropriate to implement the same purpose and effect that this Section 2.02 has with respect to shares of Progress Common Stock that are represented by Certificates.

ARTICLE III

REPRESENTATIONS AND WARRANTIES

Section 3.01 Representations and Warranties of Progress. Except as set forth in the letter dated the date of this Agreement and delivered to Duke by Progress concurrently with the execution and delivery of this Agreement (the "Progress Disclosure Letter") or, to the extent the qualifying nature of such disclosure is readily apparent therefrom and excluding any forward-looking statements, risk factors and other similar statements that are cautionary and non-specific in nature, as set forth in the Progress SEC Reports filed on or after January 1, 2009 and prior to the date hereof, Progress represents and warrants to Duke as follows:

(a) Organization and Qualification.

(i) Each of Progress and its subsidiaries is duly organized, validly existing and in good standing (with respect to jurisdictions that recognize the concept of good standing) under the laws of its jurisdiction of organization and has full power and authority to conduct its business as and to the extent now conducted and to own, use and lease its assets and properties, except for such failures to be so organized, existing and in good standing (with respect to jurisdictions that recognize the concept of good standing) or to have such power and authority that, individually or in the aggregate, have not had and could not be reasonably expected to have a material adverse effect on Progress. Each of Progress and its subsidiaries is duly qualified, licensed or admitted to do business and is in good standing (with respect to jurisdictions that recognize the concept of good standing) in each jurisdiction in which the ownership, use or leasing of its assets and properties, or the conduct or nature of its business, makes such qualification, licensing or admission necessary, except for such failures to be so qualified, licensed or admitted and in good standing (with respect to jurisdictions that recognize the concept of good standing) that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress. Section 3.01(a) of the Progress Disclosure Letter sets forth as of the date of this Agreement the name and jurisdiction of organization of each subsidiary of Progress. No subsidiary of Progress owns any stock in Progress. Progress has made available to Duke prior to the date of this Agreement a true and complete copy of Progress's articles of incorporation and by-laws, each as amended through the date hereof.

(ii) Section 3.01(a) of the Progress Disclosure Letter sets forth a description as of the date of this Agreement, of all Progress Joint Ventures, including (x) the name of each such entity and (y) a brief description of the principal line or lines of business conducted by each such entity. For purposes of this Agreement:

(A) "Joint Venture" of a person or entity shall mean any person that is not a subsidiary of such first person, in which such first person or one or more of its subsidiaries owns directly or indirectly an equity interest, other than equity interests held for passive investment purposes that are less than 5% of each class of the outstanding voting securities or equity interests of such second person;

(B) "Progress Joint Venture" shall mean any Joint Venture of Progress or any of its subsidiaries in which the invested capital associated with Progress's or its subsidiaries' interest, as of the date of this Agreement exceeds $50,000,000; and

(C) "Duke Joint Venture" shall mean any Joint Venture of Duke or any of its subsidiaries in which the invested capital associated with Duke's or its subsidiaries' interest, as of the date of this Agreement, exceeds $100,000,000.

(iii) Except for interests in the subsidiaries of Progress, the Progress Joint Ventures and interests acquired after the date of this Agreement without violating any covenant or agreement set forth herein, neither Progress nor any of its subsidiaries directly or indirectly owns any equity or similar interest in, or any interest convertible into or exchangeable or exercisable for, any equity or similar interest in, any person, in which the invested capital associated with such interest of Progress or any of its subsidiaries exceeds, individually as of the date of this Agreement, $50,000,000.

(b) Capital Stock.

(i) The authorized capital stock of Progress consists of:

(A) 500,000,000 shares of common stock, no par value (the "Progress Common Stock"), of which 293,150,141 shares were outstanding as of November 2, 2010; and

(B) 20,000,000 shares of preferred stock, no par value per share, none of which were outstanding as of the date of this Agreement.

As of the date of this Agreement, no shares of Progress Common Stock were held in the treasury of Progress. As of the date of this Agreement, 1,418,447 shares of Progress Common Stock were subject to outstanding stock options granted under the Progress Employee Stock Option Plans (collectively, the "Progress Employee Stock Options"), 1,194,888 shares of Progress Common Stock were subject to outstanding awards of restricted stock units or phantom shares of Progress Common Stock ("Progress Restricted Stock Units"), 1,875,087 shares of Progress Common Stock were subject to outstanding awards of performance shares of Progress Common Stock, determined at maximum performance levels ("Progress Performance Shares") and 1,651,047 additional shares of Progress Common Stock were reserved for issuance pursuant to the Progress Energy, Inc. 1997 Equity Incentive Plan, the Progress Energy, Inc. 2002 Equity Incentive Plan, the Progress Energy, Inc. 2007 Equity Incentive Plan, the Amended and Restated Progress Energy, Inc. Non-Employee Director Stock Unit Plan, and any other compensatory plan, program or arrangement under which shares of Progress Common Stock are reserved for issuance (collectively, the "Progress Employee Stock Option Plans"). Since November 2, 2010, no shares of Progress Common Stock have been issued except pursuant to the Progress Employee Stock Option Plans and Progress Employee Stock Options issued thereunder and the Progress Energy, Inc. Investor Plus Plan, and from November 2, 2010 to the date of this Agreement, no shares of Progress Common Stock have been issued other than 17,367 shares of Progress Common Stock issued pursuant to the Progress Employee Stock Option Plans or Progress Employee Stock Options issued thereunder and 62,489 shares of Progress Common Stock issued pursuant to the Progress Energy, Inc. Investor Plus Plan. All of the issued and outstanding shares of Progress Common Stock are, and all shares reserved for issuance will be, upon issuance in accordance with the terms specified in the instruments or agreements pursuant to which they are issuable, duly authorized, validly issued, fully paid and nonassessable. Except as disclosed in this Section 3.01(b), as of the date of this Agreement there are no outstanding subscriptions, options, warrants, rights (including stock appreciation rights), preemptive rights or other contracts, commitments, understandings or arrangements, including any right of conversion or exchange under any outstanding security, instrument or agreement (together, "Options"), obligating Progress or any of its subsidiaries (A) to issue or sell any shares of capital stock of Progress, (B) to grant, extend or enter into any Option with respect thereto, (C) redeem or otherwise acquire any such shares of capital stock or other equity interests or (D) provide a material amount of funds to, or make any material investment (in the form of a loan, capital contribution or otherwise) in, any of their respective subsidiaries.

(ii) Except as permitted by this Agreement, all of the outstanding shares of capital stock of each subsidiary of Progress are duly authorized, validly issued, fully paid and nonassessable and are owned, beneficially and of record, by Progress or a subsidiary of Progress, free and clear of any liens, claims, mortgages, encumbrances, pledges, security interests, equities and charges of any kind (each a "Lien"), except for any of the foregoing that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress. There are no (A) outstanding Options obligating Progress or any of its subsidiaries to issue or sell any shares of capital stock of any subsidiary of Progress or to grant, extend or enter into any such Option or (B) voting trusts, proxies or other commitments, understandings, restrictions or arrangements in favor of any person other than Progress or a subsidiary wholly-owned, directly or indirectly, by Progress with respect to the voting of or the right to participate in dividends or other earnings on any capital stock of Progress or any subsidiary of Progress.

(iii) Progress is a "holding company" as defined under Section 1262 of the Public Utility Holding Company Act of 2005, as amended (the "2005 Act").

(iv) As of the date of this Agreement, no bonds, debentures, notes or other indebtedness of Progress or any of its subsidiaries having the right to vote (or which are convertible into or exercisable for securities having the right to vote) (collectively, "Progress Voting Debt") on any matters on which Progress shareholders may vote are issued or outstanding nor are there any outstanding Options obligating Progress or any of its subsidiaries to issue or sell any Progress Voting Debt or to grant, extend or enter into any Option with respect thereto.

(v) There have been no repricings of any Progress Employee Stock Options through amendments, cancellation and reissuance or other means during the current or prior two (2) calendar years. None of the Progress Employee Stock Options, Progress Restricted Stock Units or Progress Performance Shares (A) have been granted since November 2, 2010, except as permitted by this Agreement, or (B) have been granted in contemplation of the Merger or the transactions contemplated in this Agreement. None of the Progress Employee Stock Options was granted with an exercise price below the per share closing price on the NYSE on the date of grant. All grants of Progress Employee Stock Options, Progress Restricted Stock Units and Progress Performance Shares were validly made and properly approved by the Board of Directors of Progress (or a duly authorized committee or subcommittee thereof) in compliance with all applicable laws and recorded on the consolidated financial statements of Progress in accordance with GAAP, and no such grants of Progress Employee Stock Options involved any "back dating," "forward dating" or similar practices.

(c) Authority. Progress has full corporate power and authority to enter into this Agreement, to perform its obligations hereunder and, subject to obtaining Progress Shareholder Approval, to consummate the transactions contemplated hereby. The execution, delivery and performance of this Agreement by Progress and the consummation by Progress of the transactions contemplated hereby have been duly and validly adopted and unanimously approved by the Board of Directors of Progress, the Board of Directors of Progress has recommended approval of this Agreement by the shareholders of Progress and directed that this Agreement be submitted to the shareholders of Progress for their approval, and no other corporate proceedings on the part of Progress or its shareholders are necessary to authorize the execution, delivery and performance of this Agreement by Progress and the consummation by Progress of the Merger and the other transactions contemplated hereby, other than obtaining Progress Shareholder Approval. This Agreement has been duly and validly executed and delivered by Progress and, assuming this Agreement constitutes the legal, valid and binding obligation of Duke and Merger Sub, constitutes a legal, valid and binding obligation of Progress enforceable against Progress in accordance with its terms, except that such enforcement may be subject to applicable bankruptcy, insolvency, reorganization, moratorium or other similar laws, now or hereafter in effect, relating to creditors' rights generally and to general equitable principles.

(d) No Conflicts; Approvals and Consents.

(i) The execution and delivery of this Agreement by Progress does not, and the performance by Progress of its obligations hereunder and the consummation of the Merger and the other transactions contemplated hereby will not, conflict with, result in a violation or breach of, constitute (with or without notice or lapse of time or both) a default under, result in or give to any person any right of payment or reimbursement, termination, cancellation, modification or acceleration of, or result in the creation or imposition of any Lien upon any of the assets or properties of Progress or any of its subsidiaries or any of the Progress Joint Ventures under, any of the terms, conditions or provisions of (A) the certificates or articles of incorporation or by-laws (or other comparable organizational documents) of Progress or any of its subsidiaries or any of the Progress Joint Ventures, or (B) subject to the obtaining of Progress Shareholder Approval and the taking of the actions described in paragraph (ii) of this Section 3.01(d), including the Progress Required Statutory Approvals, (x) any statute, law, rule, regulation or ordinance (together, "laws"), or any judgment, order, writ or decree (together, "orders"), of any federal, state, local or foreign government or any court of competent jurisdiction, administrative agency or commission or other governmental authority or instrumentality, domestic, foreign or supranational (each, a "Governmental Authority") applicable to Progress or any of its subsidiaries or any of the Progress Joint Ventures or any of their respective assets or properties, or (y) any note, bond, mortgage, security agreement, credit agreement, indenture, license, franchise, permit, concession, contract, lease, obligation or other instrument to which Progress or any of its subsidiaries or any of the Progress Joint Ventures is a party or by which Progress or any of its subsidiaries or any of the Progress Joint Ventures or any of their respective assets or properties is bound, excluding from the foregoing clauses (x) and (y) such items that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress.

(ii) Except for (A) compliance with, and filings under, the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and the rules and regulations thereunder (the "HSR Act"); (B) the filing with and, to the extent required, the declaration of effectiveness by the Securities and Exchange Commission (the "SEC") of (1) a proxy statement relating to the approval of this Agreement by Progress's shareholders (such proxy statement, together with the proxy statement relating to the approval of this Agreement by Duke's shareholders, in each case as amended or supplemented from time to time, the "Joint Proxy Statement") pursuant to the Securities Exchange Act of 1934, as amended, and the rules and regulations thereunder (the "Exchange Act"), (2) the registration statement on Form S-4 prepared in connection with the issuance of Duke Common Stock in the Merger (the "Form S-4") and (3) such reports under the Exchange Act as may be required in connection with this Agreement and the transactions contemplated hereby; (C) the filing of documents with various state securities authorities that may be required in connection with the transactions contemplated hereby; (D) such filings with and approvals of the NYSE to permit the shares of Duke Common Stock that are to be issued pursuant to Article II to be listed on the NYSE; (E) the registration, consents, approvals and notices required under the 2005 Act; (F) notice to, and the consent and approval of, the Federal Energy Regulatory Commission (the "FERC") under Section 203 of the Federal Power Act, as amended (the "Power Act"), or an order under the Power Act disclaiming jurisdiction over the transactions contemplated hereby; (G) the filing of an application to, and consent and approval of, and issuance of any required licenses and license amendments by, the Nuclear Regulatory Commission (the "NRC") under the Atomic Energy Act of 1954, as amended (the "Atomic Energy Act"); (H) the filing of the

Articles of Merger and other appropriate merger documents required by the NCBCA with the Secretary of State of the State of North Carolina and appropriate documents with the relevant authorities of other states in which Progress is qualified to do business; (I) compliance with and such filings as may be required under applicable Environmental Laws; (J) to the extent required, notice to and the approval of the North Carolina Utilities Commission (the "NCUC"), the Public Service Commission of South Carolina (the "PSCSC"), the Florida Public Service Commission (the "FPSC"), the Public Utilities Commission of Ohio (the "PUCO"), the Indiana Utility Regulatory Commission (the "IURC") and the Kentucky Public Service Commission (the "KPSC") (collectively, the "Applicable PSCs"); (K) required pre-approvals (the "FCC Pre-Approvals") of license transfers with the Federal Communications Commission (the "FCC"); (L) such other items as disclosed in Section 3.01(d) of the Progress Disclosure Letter; and (M) compliance with, and filings under, antitrust or competition laws of any foreign jurisdiction, if required (the items set forth above in clauses (A) through (H) and (J), collectively, the "Progress Required Statutory Approvals"), no consent, approval, license, order or authorization ("Consents") or action of, registration, declaration or filing with or notice to any Governmental Authority is necessary or required to be obtained or made in connection with the execution and delivery of this Agreement by Progress, the performance by Progress of its obligations hereunder or the consummation of the Merger and the other transactions contemplated hereby, other than such items that the failure to make or obtain, as the case may be, individually or in the aggregate, could not reasonably be expected to have a material adverse effect on Progress.

(e) SEC Reports, Financial Statements and Utility Reports.

(i) Progress and its subsidiaries have filed or furnished each form, report, schedule, registration statement, registration exemption, if applicable, definitive proxy statement and other document (together with all amendments thereof and supplements thereto) required to be filed or furnished by Progress or any of its subsidiaries pursuant to the Securities Act of 1933, as amended, and the rules and regulations thereunder (the "Securities Act") or the Exchange Act with the SEC since January 1, 2007 (as such documents have since the time of their filing been amended or supplemented, the "Progress SEC Reports"). As of their respective dates, after giving effect to any amendments or supplements thereto, the Progress SEC Reports (A) complied as to form in all material respects with the requirements of the Securities Act and the Exchange Act, if applicable, as the case may be, and, to the extent applicable, the Sarbanes-Oxley Act of 2002 ("SOX"), and (B) did not contain any untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading.

(ii) Each of the principal executive officer of Progress and the principal financial officer of Progress (or each former principal executive officer of Progress and each former principal financial officer of Progress, as applicable) has made all certifications required by Rule 13a-14 or 15d-14 under the Exchange Act or Sections 302 and 906 of SOX and the rules and regulations of the SEC promulgated thereunder with respect to the Progress SEC Reports. For purposes of the preceding sentence, "principal executive officer" and "principal financial officer" shall have the meanings given to such terms in SOX. Since January 1, 2007, neither Progress nor any of its subsidiaries has arranged any outstanding "extensions of credit" to directors or executive officers within the meaning of Section 402 of SOX.

(iii) The audited consolidated financial statements and unaudited interim consolidated financial statements (including, in each case, the notes, if any, thereto) included in the Progress SEC Reports (the "Progress Financial Statements") complied as to form in all material respects with the published rules and regulations of the SEC with respect thereto in effect at the time of filing or furnishing the applicable Progress SEC Report, were prepared in accordance with United States generally accepted accounting principles ("GAAP") applied on a consistent basis during the periods involved (except as may be indicated therein or in the notes thereto and except with respect to unaudited statements as permitted by Form 10-Q of the SEC) and fairly present (subject, in the case of the unaudited interim financial statements, to normal, recurring year-end audit adjustments that were not or are not expected to be, individually or in the aggregate, materially adverse to Progress) the consolidated financial position of Progress and its consolidated subsidiaries as of the respective dates thereof and the consolidated results of their operations and cash flows for the respective periods then ended.

(iv) All filings (other than immaterial filings) required to be made by Progress or any of its subsidiaries since January 1, 2007, under the 2005 Act, the Power Act, the Atomic Energy Act, the Natural Gas Act, the Natural Gas Policy Act of 1978, the Communications Act of 1934 and applicable state laws and regulations, have been filed with the SEC, the FERC, the Department of Energy (the "DOE"), the FCC or any applicable state public utility commissions (including, to the extent required, NCUC, PSCSC and FPSC), as the case may be, including all forms, statements, reports, agreements (oral or written) and all documents, exhibits, amendments and supplements appertaining thereto, including all rates, tariffs, franchises, service agreements and related documents, and all such filings complied, as of their respective dates, with all applicable requirements of the applicable statute and the rules and regulations thereunder, except for filings the failure of which to make or the failure of which to make in compliance with all applicable requirements of the applicable statute and the rules and regulations thereunder, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress.

(v) Progress has designed and maintains a system of internal control over financial reporting (as defined in Rules 13a–15(f) and 15d–15(f) of the Exchange Act) sufficient to provide reasonable assurances regarding the reliability of financial reporting. Progress (x) has designed and maintains disclosure controls and procedures (as defined in Rules 13a–15(e) and 15d–15(e) of the Exchange Act) to provide reasonable assurance that all information required to be disclosed by Progress in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and is accumulated and communicated to Progress's management as appropriate to allow timely decisions regarding required disclosure, and (y) has disclosed, based on its most recent evaluation of internal control over financial reporting, to Progress's outside auditors and the audit committee of the Board of Directors of Progress (A) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect Progress's ability to record, process, summarize and report financial information and (B) any fraud, whether or not material, that involves management or other employees who have a significant role in Progress's internal control over financial reporting. Since December 31, 2006, any material change in internal control over financial reporting required to be disclosed in any Progress SEC Report has been so disclosed.

(vi) Since December 31, 2006, (x) neither Progress nor any of its subsidiaries nor, to the knowledge of the Executive Officers (for the purposes of this Section 3.01(e)(vi), as such term is defined in Section 3b-7 of the Exchange Act) of Progress, any director, officer, employee, auditor, accountant or representative of Progress or any of its subsidiaries has received or otherwise obtained knowledge of any material complaint, allegation, assertion or claim, whether written or oral, regarding the accounting or auditing practices, procedures, methodologies or methods of Progress or any of its subsidiaries or their respective internal accounting controls relating to periods after December 31, 2006, including any material complaint, allegation, assertion or claim that Progress or any of its subsidiaries has engaged in questionable accounting or auditing practices (except for any of the foregoing after the date hereof which have no reasonable basis), and (y) to the knowledge of the Executive Officers of Progress, no attorney representing Progress or any of its subsidiaries, whether or not employed by Progress or any of its subsidiaries, has reported evidence of a material violation of securities laws, breach of fiduciary duty or similar violation, relating to periods after December 31, 2006, by Progress or any of its officers, directors, employees or agents to the Board of Directors of Progress or any committee thereof or to any director or Executive Officer of Progress.

(f) Absence of Certain Changes or Events. Since December 31, 2009, through the date hereof, Progress and its subsidiaries have conducted their respective businesses in all material respects in the ordinary course of business in a consistent manner since such date and there has not been any change, event or development that, individually or in the aggregate, has had or could reasonably be expected to have a material adverse effect on Progress.

(g) Absence of Undisclosed Liabilities. Except for matters reflected or reserved against in the consolidated balance sheet (or notes thereto) as of December 31, 2009, included in the Progress Financial Statements, neither Progress nor any of its subsidiaries has any liabilities or obligations (whether absolute, accrued, contingent, fixed or otherwise, or whether due or to become due) of any nature that would be required by GAAP to be reflected on a consolidated balance sheet of Progress and its consolidated subsidiaries (including the notes thereto), except liabilities or obligations (i) that were incurred in the ordinary course of business consistent with past practice since December 31, 2009, (ii) that were incurred in connection with the transactions contemplated by this Agreement and that are not material in the aggregate or (iii) that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress. Neither Progress nor any of its subsidiaries is a party to, or has any commitment to become a party to, any joint venture, off-balance sheet partnership or any similar contract or arrangement (including any Contract relating to any transaction or relationship between or among Progress and any of its subsidiaries, on the one hand, and any unconsolidated affiliate, including any structured finance, special purpose or limited purpose entity or person, on the other hand, or any "off-balance sheet arrangements" (as defined in Item 303(a) of Regulation S-K under the Exchange Act), where the result, purpose or effect of such contract or arrangement is to avoid disclosure of any material transaction involving, or material liabilities of, Progress or any of its subsidiaries, in the Progress Financial Statements or the Progress SEC Reports.

(h) Legal Proceedings. Except for Environmental Claims, which are the subject of Section 3.01(n), as of the date of this Agreement, (i) there are no actions, suits, arbitrations or proceedings pending or, to the knowledge of Progress, threatened against, relating to or affecting, nor to the knowledge of Progress are there any Governmental Authority investigations, inquiries or audits pending or threatened against, relating to or affecting, Progress or any of its subsidiaries or any of the Progress Joint Ventures or any of their respective assets and properties that, in each case, individually or in the aggregate, have had or could reasonably be expected to have a material adverse effect on Progress and (ii) neither Progress nor any of its subsidiaries or material assets is subject to any order of any Governmental Authority that, individually or in the aggregate, has had or could reasonably be expected to have a material adverse effect on Progress.

(i) Information Supplied. None of the information supplied or to be supplied by Progress for inclusion or incorporation by reference in (i) the Form S-4 will, at the time the Form S-4 is filed with the SEC, at any time it is amended or supplemented or at the time it becomes effective under the Securities Act, contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary to make the statements therein not misleading, or (ii) the Joint Proxy Statement will, at the date it is first mailed to Duke's shareholders or Progress's shareholders or at the time of the Progress Shareholders Meeting or the Duke Shareholders Meeting, contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they are made, not misleading. The Joint Proxy Statement (other than the portions thereof relating solely to the Duke Shareholders Meeting) will comply as to form in all material respects with the requirements of the Exchange Act and the rules and regulations thereunder, except that no representation is made by Progress with respect to statements made or incorporated by reference therein based on information supplied by or on behalf of Duke or Merger Sub for inclusion or incorporation by reference in the Joint Proxy Statement.

(j) Permits; Compliance with Laws and Orders. Progress, its subsidiaries and the Progress Joint Ventures hold all permits, licenses, certificates, notices, authorizations, approvals and similar Consents of all Governmental Authorities ("Permits") necessary for the lawful conduct of their respective businesses, except for failures to hold such Permits that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress. Progress, its subsidiaries and the Progress Joint Ventures are in compliance with the terms of their Permits, except failures so to comply that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress. Progress, its subsidiaries and the Progress Joint Ventures are not, and since January 1, 2008 have not been, in violation of or default under any law or order of any Governmental Authority, except for such violations or defaults that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress. Progress is, and since January 1, 2008 has been, in compliance in all material respects with (i) SOX and (ii) the applicable listing standards and corporate governance rules and regulations of the NYSE. The above provisions of this Section 3.01(j) do not relate to matters with respect to taxes, such matters being the subject of Section 3.01(k), Environmental Permits and Environmental Laws, such matters being the subject of Section 3.01(n), benefits plans, such matters being the subject of Section 3.01(l) and nuclear power plants, such matters being the subject of Section 3.01(o).

(k) Taxes.

(i) Except as has not had, and could not reasonably be expected to have, a material adverse effect on Progress:

(A) Each of Progress and its subsidiaries has timely filed, or has caused to be timely filed on its behalf, all Tax Returns required to be filed by it, and all such Tax Returns are true, complete and accurate. All Taxes shown to be due and owing on such Tax Returns have been timely paid.

(B) The most recent financial statements contained in the Progress SEC Reports filed prior to the date of this Agreement reflect, in accordance with GAAP, an adequate reserve for all Taxes payable by Progress and its subsidiaries for all taxable periods through the date of such financial statements.

(C) There is no audit, examination, deficiency, refund litigation, proposed adjustment or matter in controversy with respect to any Taxes or Tax Return of Progress or its subsidiaries, and, to the knowledge of Progress, neither Progress nor any of its subsidiaries has received written notice of any claim made by a governmental authority in a jurisdiction where Progress or any of its subsidiaries, as applicable, does not file a Tax Return, that Progress or such subsidiary is or may be subject to income taxation by that jurisdiction. No deficiency with respect to any Taxes has been proposed, asserted or assessed against Progress or any of its subsidiaries, and no requests for waivers of the time to assess any Taxes are pending.

(D) There are no outstanding written agreements, consents or waivers to extend the statutory period of limitations applicable to the assessment of any Taxes or deficiencies against Progress or any of its subsidiaries, and no power of attorney granted by either Progress or any of its subsidiaries with respect to any Taxes is currently in force.

(E) Neither Progress nor any of its subsidiaries is a party to any agreement providing for the allocation or sharing of Taxes imposed on or with respect to any individual or other person (other than (I) such agreements with customers, vendors, lessors or the like entered into in the ordinary course of business and (II) agreements with or among Progress or any of its subsidiaries), and neither Progress nor any of its subsidiaries (A) has been a member of an affiliated group (or similar state, local or foreign filing group) filing a consolidated U.S. federal income Tax Return (other than the group the common parent of which is Progress or a subsidiary of Progress) or (B) has any liability for the Taxes of any person (other than Progress or any of its subsidiaries) (I) under Treasury Regulation Section 1.1502-6 (or any similar provision of state, local or foreign law), or (II) as a transferee or successor.

(F) There are no material Liens for Taxes (other than for current Taxes not yet due and payable) on the assets of Progress and its subsidiaries.

(ii) Neither Progress nor any of its subsidiaries has taken or agreed to take any action or knows of any fact, agreement, plan or other circumstance that is reasonably likely to prevent or impede the Merger from qualifying as a reorganization under Section 368(a) of the Code.

For purposes of this Agreement:

"Taxes" means any and all federal, state, local, foreign or other taxes of any kind (together with any and all interest, penalties, additions to tax and additional amounts imposed with respect thereto) imposed by any governmental authority, including, without limitation, taxes or other charges on or with respect to income, franchises, windfall or other profits, gross receipts, property, sales, use, capital stock, payroll, employment, unemployment, social security, workers' compensation, or net worth, and taxes or other charges in the nature of excise, withholding, ad valorem or value added.

"Tax Return" means any return, report or similar statement (including the schedules attached thereto) required to be filed with respect to Taxes, including, without limitation, any information return, claim for refund, amended return, or declaration of estimated Taxes.

(l) Employee Benefit Plans; ERISA.

(i) Except for such matters that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress, (A) all Progress Employee Benefit Plans are in compliance with all applicable requirements of law, including the Employee Retirement Income Security Act of 1974, as amended, and the rules and regulations thereunder ("ERISA"), and the Code, and (B) there does not now exist, nor do any circumstances exist that could result in, any Controlled Group Liability that would be a liability of Progress or any of its subsidiaries following the Closing. The only material employment agreements, severance agreements or severance policies applicable to Progress or any of its subsidiaries are the agreements and policies disclosed in Section 3.01(l)(i) of the Progress Disclosure Letter.

(ii) As used herein:

(A) "Controlled Group Liability" means any and all liabilities (1) under Title IV of ERISA, (2) under Section 302 of ERISA, (3) under Sections 412 and 4971 of the Code, and (4) as a result of a failure to comply with the continuation coverage requirements of Section 601 et seq. of ERISA and Section 4980B of the Code;

(B) "Progress Employee Benefit Plan" means any Plan entered into, established, maintained, sponsored, contributed to or required to be contributed to by Progress or any of its subsidiaries for the benefit of the current or former employees or directors of Progress or any of its subsidiaries and existing on the date of this Agreement or at any time subsequent thereto and, in the case of a Plan that is subject to Part 3 of Title I of ERISA, Section 412 of the Code or Title IV of ERISA, at any time during the five-year period preceding the date of this Agreement with respect to which Progress or any of its subsidiaries has or could reasonably be expected to have any present or future actual or contingent liabilities; and

(C) "Plan" means any employment, bonus, incentive compensation, deferred compensation, long term incentive, pension, profit sharing, retirement, stock purchase, stock option, stock ownership, stock appreciation rights, phantom stock, leave of absence, layoff, vacation, day or dependent care, legal services, cafeteria, life, health, medical, accident, disability, workmen's compensation or other insurance, retention, severance, separation, termination, change of control or other benefit plan, agreement, practice, policy, program, scheme or arrangement of any kind, whether written or oral, including any "employee benefit plan" within the meaning of Section 3(3) of ERISA.

(iii) No event has occurred, and there exists no condition or set of circumstances in connection with any Progress Employee Benefit Plan, that has had or could reasonably be expected to have a material adverse effect on Progress.

(iv) Section 3.01(l)(iv) of the Progress Disclosure Letter identifies each Progress Employee Benefit Plan that provides, upon the occurrence of a change in the ownership or effective control of Progress or its subsidiaries or a change in the ownership of all or a substantial portion of the assets of Progress or its subsidiaries, either alone or upon the occurrence of any additional or subsequent events and whether or not applicable to the transactions contemplated by this Agreement, for (A) an acceleration of the time of payment of or vesting in, or an increase in the amount of, compensation or benefits due any current or former employee, director or officer of Progress or its subsidiaries, (B) any forgiveness of indebtedness or obligation to fund compensation or benefits with respect to any such employee, director or officer, or (C) an entitlement of any such employee, director or officer to severance pay, unemployment compensation or any other payment or other benefit.

(v) Each Progress Employee Benefit Plan that is in any part a "nonqualified deferred compensation plan" subject to Section 409A of the Code (A) materially complies and, at all times after December 31, 2008 has materially complied, both in form and operation, with the requirements of Section 409A of the Code and the final regulations thereunder and (B) between January 1, 2005 and December 31, 2008 was operated in material reasonable, good faith compliance with Section 409A of the Code, as determined under applicable guidance of the United States Department of the Treasury (the "Treasury") and the Internal Revenue Service.

(m) Labor Matters. As of the date hereof, neither Progress nor any of its subsidiaries is a party to, bound by or in the process of negotiating any collective bargaining agreement or other labor agreement with any union or labor organization. As of the date of this Agreement, there are no disputes, grievances or arbitrations pending or, to the knowledge of Progress, threatened between Progress or any of its subsidiaries and any trade union or other representatives of its employees and there is no charge or complaint pending or threatened in writing against Progress or any of its subsidiaries before the National Labor Relations Board (the "NLRB") or any similar Governmental Authority, except in each case as, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress, and, to the knowledge of Progress, as of the date of this Agreement, there are no material organizational efforts presently being made involving any of the employees of Progress or any of its subsidiaries. From December 31, 2007, to the date of this Agreement, there has been no work stoppage, strike, slowdown or lockout by or affecting employees of Progress or any of its subsidiaries and, to the knowledge of Progress, no such action has been threatened in writing, except in each case as, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress. Except as, individually or in the aggregate, has not had and could not reasonably be expected to have a material adverse effect on Progress: (A) there are no litigations, lawsuits, claims, charges, complaints, arbitrations, actions, investigations or proceedings pending or, to the knowledge of Progress, threatened between or involving Progress or any of its subsidiaries and any of their respective current or former employees, independent contractors, applicants for employment or classes of the foregoing; (B) Progress and its subsidiaries are in compliance with all applicable laws, orders, agreements, contracts and policies respecting employment and employment practices, including, without limitation, all legal requirements respecting terms and conditions of employment, equal opportunity, workplace health and safety, wages and hours, child labor, immigration, discrimination, disability rights or benefits, facility closures and layoffs, workers' compensation, labor relations, employee leaves and unemployment insurance; and (C) since January 1, 2007, neither Progress nor any of its subsidiaries has engaged in any "plant closing" or "mass layoff," as defined in the Worker Adjustment Retraining and Notification Act or any comparable state or local law (the "WARN Act"), without complying with the notice requirements of such laws.

(n) Environmental Matters.

(i) Each of Progress, its subsidiaries and the Progress Joint Ventures since January 1, 2008 has been and is in compliance with all applicable Environmental Laws (as hereinafter defined), except where the failure to be in such compliance, individually or in the aggregate, has not had and could not reasonably be expected to have a material adverse effect on Progress.

(ii) Each of Progress, its subsidiaries and the Progress Joint Ventures has obtained all Permits under Environmental Laws (collectively, the "Environmental Permits") necessary for the construction of their facilities and the conduct of their operations as of the date of this Agreement, as applicable, and all such Environmental Permits are validly issued, in full force and effect, and final, and Progress, its subsidiaries and the Progress Joint Ventures are in compliance with all terms and conditions of the Environmental Permits, except where the failure to obtain such Environmental Permits, of such Permits to be in good standing or, where applicable, of a renewal application to have been timely filed and be pending or to be in such compliance, individually or in the aggregate, has not had and could not reasonably be expected to have a material adverse effect on Progress.

(iii) There is no Environmental Claim (as hereinafter defined) pending:

(A) against Progress or any of its subsidiaries or any of the Progress Joint Ventures;

(B) to the knowledge of Progress, against any person or entity whose liability for such Environmental Claim has been retained or assumed either contractually or by operation of law by Progress or any of its subsidiaries or any of the Progress Joint Ventures; or

(C) against any real or personal property or operations that Progress or any of its subsidiaries or any of the Progress Joint Ventures owns, leases or manages, in whole or in part, or, to the knowledge of Progress, formerly owned, leased or managed, in whole or in part, except in the case of clause (A), (B) or (C) for such Environmental Claims that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress.

(iv) To the knowledge of Progress, there have not been any Releases (as hereinafter defined) of any Hazardous Material (as hereinafter defined) that would be reasonably likely to form the basis of any Environmental Claim against Progress or any of its subsidiaries or any of the Progress Joint Ventures, in each case, except for such Releases that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress.

(v) As used in this Section 3.01(n) and in Section 3.02(n):

(A) "Environmental Claim" means any and all administrative, regulatory or judicial actions, suits, orders, demands, demand letters, directives, claims, liens, investigations, proceedings or notices of noncompliance, liability or violation (written or oral) by any person or entity (including any Governmental Authority) alleging potential liability (including potential responsibility or liability for enforcement, investigatory costs, cleanup costs, governmental response costs, removal costs, remedial costs, natural resources damages, property damages, personal injuries or penalties) arising out of, based on or resulting from circumstances forming the basis of any actual or alleged noncompliance with, violation of, or liability under, any Environmental Law or Environmental Permit;

(B) "Environmental Laws" means all domestic or foreign federal, state and local laws, principles of common law and orders relating to pollution, the environment (including ambient air, surface water, groundwater, land surface or subsurface strata) or protection of human health as it relates to the environment including laws relating to the presence or Release of Hazardous Materials, or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, disposal, transport or handling of, or exposure to, Hazardous Materials;

(C) "Hazardous Materials" means (a) any petroleum or petroleum products, radioactive materials, asbestos in any form that is or could become friable, urea formaldehyde foam insulation, and polychlorinated biphenyls; and (b) any chemical, material, substance or waste that is prohibited, limited or regulated under any Environmental Law; and

(D) "Release" means any, spill, emission, leaking, injection, deposit, disposal, discharge, dispersal, leaching or migration into the atmosphere, soil, surface water, groundwater or property.

(o) Ownership of Nuclear Power Plants. The operations of the nuclear generation stations owned, in whole or part, by Progress or its subsidiaries (collectively, the "Progress Nuclear Facilities") are and have been conducted in compliance with all applicable laws and Permits, except for such failures to comply that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress. Each of the

Progress Nuclear Facilities maintains, and is in material compliance with, emergency plans designed to respond to an unplanned Release therefrom of radioactive materials and each such plan conforms with the requirements of applicable law in all material respects. The plans for the decommissioning of each of the Progress Nuclear Facilities and for the storage of spent nuclear fuel conform with the requirements of applicable law in all material respects and, solely with respect to the portion of the Progress Nuclear Facilities owned, directly or indirectly, by Progress, are funded consistent with applicable law. Since December 31, 2008, the operations of the Progress Nuclear Facilities have not been the subject of any notices of violation, any ongoing proceeding, NRC Diagnostic Team Inspections or requests for information from the NRC or any other agency with jurisdiction over such facility, except for such notices or requests for information that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress. No Progress Nuclear Facility is listed by the NRC in the Unacceptable Performance column of the NRC Action Matrix, as a part of NRC's Assessment of Licensee Performance. Liability insurance to the full extent required by law for operating the Progress Nuclear Facilities remains in full force and effect regarding such facilities, except for failures to maintain such insurance in full force and effect that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress.

(p) Vote Required. Assuming the accuracy of the representation and warranty contained in Section 3.02(r), the affirmative vote of the holders of record of at least a majority of the outstanding shares of Progress Common Stock, with respect to the approval of this Agreement (the "Progress Shareholder Approval"), is the only vote of the holders of any class or series of the capital stock of Progress or its subsidiaries required to approve this Agreement, the Merger and the other transactions contemplated hereby.

(q) Opinions of Financial Advisors. The Board of Directors of Progress has received the opinion of each of Lazard Freres & Co. LLC and Barclays Capital Inc., to the effect that, as of the date of such opinion and based on the assumptions, qualifications and limitations contained therein, the Exchange Ratio is fair, from a financial point of view, to the holders of Progress Common Stock.

(r) Ownership of Duke Capital Stock. Neither Progress nor any of its subsidiaries or other affiliates beneficially owns any shares of Duke capital stock.

(s) Articles 9 and 9A of the NCBCA Not Applicable; Other Statutes. Progress has taken all necessary actions, if any, so that the provisions of Articles 9 and 9A of the NCBCA will not, before the termination of this Agreement, apply to this Agreement, the Merger or the other transactions contemplated hereby. No "fair price," "merger moratorium," "control share acquisition," or other anti-takeover or similar statute or regulation applies or purports to apply to this Agreement, the Merger or the other transactions contemplated hereby.

(t) Joint Venture Representations. Each representation or warranty made by Progress in this Section 3.01 relating to a Progress Joint Venture that is neither operated nor managed solely by Progress or a Progress subsidiary shall be deemed made only to the knowledge of Progress.

(u) Insurance. Except for failures to maintain insurance or self-insurance that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Progress, from January 1, 2007, through the date of this Agreement, each of Progress and its subsidiaries has been continuously insured with financially responsible insurers or has self-insured, in each case in such amounts and with respect to such risks and losses as are customary for companies in the United States conducting the business conducted by Progress and its subsidiaries during such time period. Neither Progress nor any of its subsidiaries has received any notice of any pending or threatened cancellation, termination or premium increase with respect to any insurance policy of Progress or any of its subsidiaries, except with respect to any cancellation, termination or premium increase that, individually or in the aggregate, has not had and could not reasonably be expected to have a material adverse effect on Progress.

(v) Energy Price Risk Management. Progress has established risk parameters, limits and guidelines in compliance with the risk management policy approved by Progress's Board of Directors (the "Progress Risk Management Guidelines") and monitors compliance by Progress and its subsidiaries with such energy price risk parameters. Progress has provided the Progress Risk Management Guidelines to Duke prior to the date of this Agreement. Progress is in compliance in all material respects with the Progress Risk Management Guidelines.

(w) Progress Material Contracts.

(i) For purposes of this Agreement, the term "Progress Material Contract" shall mean any Contract to which Progress or any of its subsidiaries is a party or bound as of the date hereof:

(A) that is a "material contract" (as such term is defined in Item 601(b)(10) of Regulation S-K of the SEC);

(B) that (1) purports to limit in any material respect either the type of business in which Progress or its subsidiaries (or, after the Effective Time, Duke or its subsidiaries) or any of their respective affiliates may engage or the manner or geographic area in which any of them may so engage in any business, (2) would require the disposition of any material assets or line of business of Progress or its subsidiaries (or, after the Effective Time, Duke or its subsidiaries) or any of their respective affiliates as a result of the consummation of the transactions contemplated by this Agreement, (3) is a material Contract that grants "most favored nation" status that, following the Effective Time, would impose obligations upon Duke or its subsidiaries, including Progress and its subsidiaries, or (4) prohibits or limits, in any material respect, the right of Progress or any of its subsidiaries (or, after the Effective Time, Duke or its subsidiaries) to make, sell or distribute any products or services or use, transfer, license or enforce any of their respective intellectual property rights; or

(C) that (1) has an aggregate principal amount, or provides for an aggregate obligation, in excess of $100,000,000 (I) evidencing indebtedness for borrowed money of Progress or any of its subsidiaries to any third party, (II) guaranteeing any such indebtedness of a third party or (III) containing a covenant restricting the payment of dividends, or (2) has the economic effect of any of the items set forth in subclause (1) above.

(ii) Neither Progress nor any subsidiary of Progress is in breach of or default under the terms of any Progress Material Contract and no event has occurred that (with or without notice or lapse of time or both) could result in a breach or default under any Progress Material Contract where such breach or default could reasonably be expected to have, individually or in the aggregate, a material adverse effect on Progress. To the knowledge of Progress, no other party to any Progress Material Contract is in breach of or default under the terms of any Progress Material Contract where such breach or default has had, or could reasonably be expected to have, individually or in the aggregate, a material adverse effect on Progress. Except as could not reasonably be expected to have, individually or in the aggregate, a material adverse effect on Progress, each Progress Material Contract is a valid and binding obligation of Progress or the subsidiary of Progress which is party thereto and, to the knowledge of Progress, of each other party thereto, and is in full force and effect, except that such enforcement may be subject to applicable bankruptcy, insolvency, reorganization, moratorium or other similar laws, now or hereafter in effect, relating to creditors' rights generally and to general equitable principles.

(x) Anti-Bribery Laws.

(i) To the knowledge of Progress, Progress and its subsidiaries are, and since January 1, 2008, have been, in compliance in all material respects with all statutory and regulatory requirements under the Foreign Corrupt Practices Act (15 U.S.C. §§ 78dd-1, et seq.), as amended, the Anti-Kickback Act of 1986, as amended, the Organization for Economic Cooperation and Development Convention Against Bribery of Foreign Officials in International Business Transactions and all legislation implementing such convention and all other international anti-bribery conventions, and all other anti-corruption and bribery laws (including any applicable written standards, requirements, directives or policies of any Governmental Authority) (the "Anti-Bribery Laws") in jurisdictions in which Progress and its subsidiaries have operated or currently operate. Since January 1, 2008, neither Progress nor any of its subsidiaries has received any communication from any Governmental Authority or any written communication from any third party that alleges that Progress, any of its subsidiaries or any employee or agent thereof is in material violation of any Anti-Bribery Laws, and no such potential or actual material violation or liability has been discovered.

(ii) Without limiting the other provisions of this Section 3.01(x), since January 1, 2008, none of Progress or its subsidiaries nor, to the knowledge of Progress, any of their respective current or former directors, officers, principals, employees, managers, sales persons, consultants or other agents or representatives, distributors, contractors, joint venturers or any other person acting on any of their behalf, has, directly or indirectly, made or offered or solicited or accepted any contribution, gift, gratuity, entertainment, bribe, rebate, payoff, influence payment, kickback or other payment or anything else of value to or from any person, private or public (including customers, potential customers, political parties, elected officials and candidates), whether in money, property, services or any other form, to influence any act of such person in such person's official capacity, inducing such person to do or omit to do any act in violation of the lawful official duty of such person or securing an improper advantage or to induce such person to use such person's influence to obtain or retain business for Progress or its subsidiaries or otherwise to confer any benefit to Progress or its subsidiaries in violation in any material respect of any Anti-Bribery Laws.

(iii) Since January 1, 2006, neither Progress nor any of its subsidiaries has made any disclosure (voluntary or otherwise) to any Governmental Authority with respect to any alleged material irregularity, material misstatement or material omission or other potential material violation or liability arising under or relating to any Anti-Bribery Law.

Section 3.02 Representations and Warranties of Duke and Merger Sub. Except as set forth in the letter dated the date of this Agreement and delivered to Progress by Duke concurrently with the execution and delivery of this Agreement (the "Duke Disclosure Letter") or, to the extent the qualifying nature of such disclosure is readily apparent therefrom and excluding any forward-looking statements, risk factors and other similar statements that are cautionary and non-specific in nature, as set forth in the Duke SEC Reports filed on or after January 1, 2009 and prior to the date hereof, Duke and Merger Sub represent and warrant to Progress as follows:

(a) Organization and Qualification.

(i) Each of Duke and its subsidiaries is duly organized, validly existing and in good standing (with respect to jurisdictions that recognize the concept of good standing) under the laws of its jurisdiction of organization and has full power and authority to conduct its business as and to the extent now conducted and to own, use and lease its assets and properties, except for such failures to be so organized, existing and in good standing (with respect to jurisdictions that recognize the concept of good standing) or to have such power and authority that, individually or in the aggregate, have not had and could not be reasonably expected to have a material adverse effect on Duke. Each of Duke and its subsidiaries is duly qualified, licensed or admitted to do business and is in good standing (with respect to jurisdictions that recognize the concept of good standing) in each jurisdiction in which the ownership, use or leasing of its assets and properties, or the conduct or nature of its business, makes such qualification, licensing or admission necessary, except for such failures to be so qualified, licensed or admitted and in good standing (with respect to jurisdictions that recognize the concept of good standing) that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke. Section 3.02(a) of the Duke Disclosure Letter sets forth as of the date of this Agreement the name and jurisdiction of organization of each subsidiary of Duke. Merger Sub is a newly formed corporation and has engaged in no activities except as contemplated by this Agreement. All of the outstanding capital stock of Merger Sub is owned directly by Duke. No subsidiary of Duke owns any stock in Duke. Duke has made available to Progress prior to the date of this Agreement a true and complete copy of Duke's certificate of incorporation and by-laws, each as amended through the date hereof.

(ii) Section 3.02(a) of the Duke Disclosure Letter sets forth a description as of the date of this Agreement, of all Duke Joint Ventures, including (x) the name of each such entity and (y) a brief description of the principal line or lines of business conducted by each such entity.

(iii) Except for interests in the subsidiaries of Duke, the Duke Joint Ventures and interests acquired after the date of this Agreement without violating any covenant or agreement set forth herein, neither Duke nor any of its subsidiaries directly or indirectly owns any equity or similar interest in, or any interest convertible into or exchangeable or exercisable for, any equity or similar interest in, any person, in which the invested capital associated with such interest of Duke or any of its subsidiaries exceeds, individually as of the date of this Agreement, $100,000,000.

(b) Capital Stock.

(i) The authorized capital stock of Duke consists of:

(A) 2,000,000,000 shares of common stock, par value $0.001 per share (the "Duke Common Stock"), of which 1,324,548,714 shares were outstanding as of October 29, 2010; and

(B) 44,000,000 shares of preferred stock, par value $0.001 per share, none of which were outstanding as of the date of this Agreement.

As of the date of this Agreement, no shares of Duke Common Stock are held in the treasury of Duke. As of the date of this Agreement, 13,869,567 shares of Duke Common Stock were subject to outstanding stock options granted under the Duke Employee Stock Option Plans ("Duke Employee Stock Options"), 1,756,064 shares of Duke Common Stock were subject to outstanding awards of phantom stock units of Duke Common Stock ("Duke Phantom Stock Units"), 7,549,720 shares of Duke Common Stock were subject to outstanding awards of performance shares of Duke Common Stock, determined at maximum performance levels ("Duke Performance Shares") and 75,901,515 additional shares of Duke Common Stock were reserved for issuance pursuant to the Duke Power Company Stock Incentive Plan, the Duke Energy Corporation 1998 Long-Term Incentive Plan, the Duke Energy Corporation 2006 Long-Term Incentive Plan, the Duke Energy Corporation 2010 Long-Term Incentive Plan, the Duke Energy Corporation Directors' Savings Plan, the Duke Energy Corporation Executive Savings Plan and any other compensatory plan, program or arrangement under which shares of Duke Common Stock are reserved for issuance (collectively, the "Duke Employee Stock Option Plans"). Since October 29, 2010, no shares of Duke Common Stock have been issued except pursuant to the Duke Employee Stock Option Plans and Duke Employee Stock Options issued thereunder, and from October 29, 2010 to the date of this Agreement, no shares of Duke Common Stock have been issued other than 268,498 shares of Duke Common Stock issued pursuant to the Duke Employee Stock Option Plans or Duke Employee Stock Options issued thereunder. All of the issued and outstanding shares of Duke Common Stock are, and all shares reserved for issuance will be, upon issuance in accordance with the terms specified in the instruments or agreements pursuant to which they are issuable, duly authorized, validly issued, fully paid and nonassessable. Except as disclosed in this Section 3.02(b), as of date of this Agreement there are no outstanding Options obligating Duke or any of its subsidiaries (A) to issue or sell any shares of capital stock of Duke, (B) to grant, extend or enter into any Option with respect thereto, (C) redeem or otherwise acquire any such shares of capital stock or other equity interests or (D) provide a material amount of funds to, or make any material investment (in the form of a loan, capital contribution or otherwise) in, any of their respective subsidiaries.

(ii) Except as permitted by this Agreement, all of the outstanding shares of capital stock of each subsidiary of Duke are duly authorized, validly issued, fully paid and nonassessable and are owned, beneficially and of record, by Duke or a subsidiary of Duke, free and clear of any Liens, except for any of the foregoing that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke. All of the outstanding shares of capital stock of Merger Sub are duly authorized, validly issued, fully paid and nonassessable and are owned, beneficially and of record, directly by Duke. The shares of Merger Sub owned by Duke are owned free and clear of any Liens. There are no (A) outstanding Options obligating Duke or any of its subsidiaries to issue or sell any shares of capital stock of any subsidiary of Duke or to grant, extend or enter into any such Option or (B) voting trusts, proxies or other commitments, understandings, restrictions or arrangements in favor of any person other than Duke or a subsidiary wholly-owned, directly or indirectly, by Duke with respect to the voting of or the right to participate in dividends or other earnings on any capital stock of Duke or any subsidiary of Duke.

(iii) As of the date of this Agreement, none of the subsidiaries of Duke or the Duke Joint Ventures is a "public utility company," a "holding company," a "subsidiary company" or an "affiliate" of any holding company within the meaning of Section 2(a)(5), 2(a)(7), 2(a)(8) or 2(a)(11) of the 2005 Act, respectively. None of Duke, its subsidiaries and the Duke Joint Ventures is registered under the 2005 Act.

(iv) As of the date of this Agreement, no bonds, debentures, notes or other indebtedness of Duke or any of its subsidiaries having the right to vote (or which are convertible into or exercisable for securities having the right to vote) (collectively, "Duke Voting Debt") on any matters on which Duke shareholders may vote are issued or outstanding nor are there any outstanding Options obligating Duke or any of its subsidiaries to issue or sell any Duke Voting Debt or to grant, extend or enter into any Option with respect thereto.

(v) Each share of Duke Common Stock to be issued in the Merger shall be duly authorized, validly issued, fully paid and nonassessable and free and clear of any Liens.

(vi) There have been no repricings of any Duke Employee Stock Options through amendments, cancellation and reissuance or other means during the current or prior two (2) calendar years. None of the Duke Employee Stock Options, Duke Phantom Stock Units or Duke Performance Shares (A) have been granted since August 6, 2010, except as permitted by this Agreement, or (B) have been granted in contemplation of the Merger or the transactions contemplated in this Agreement. None of the Duke Employee Stock Options was granted with an exercise price below the per share closing price on the NYSE on the date of grant. All grants of Duke Employee Stock Options, Duke Phantom Stock Units and Duke Performance Shares were validly made and properly approved by the Board of Directors of Duke (or a duly authorized committee or subcommittee thereof) in compliance with all applicable laws and recorded on the consolidated financial statements of Duke in accordance with GAAP, and no such grants of Duke Employee Stock Options involved any "back dating," "forward dating" or similar practices.

(c) Authority. Duke has full corporate power and authority to enter into this Agreement, to perform its obligations hereunder and, subject to obtaining Duke Shareholder Approval, to consummate the transactions contemplated hereby. The execution, delivery and performance of this Agreement by Duke and the consummation by Duke of the transactions contemplated hereby have been duly and validly adopted and unanimously approved by the Board of Directors of Duke, the Board of Directors of Duke has recommended approval by the shareholders of Duke of the Duke Charter Amendment and the Duke Share Issuance, and directed that the Duke Charter Amendment and Duke Share Issuance be submitted to the shareholders of Duke for their approval, and no other corporate proceedings on the part of Duke or its shareholders are necessary to authorize the execution, delivery and performance of this Agreement by Duke and the consummation by Duke of the Merger and the other transactions contemplated hereby, other than obtaining Duke Shareholder Approval. This Agreement has been duly and validly executed and delivered by Duke and, assuming this Agreement constitutes the legal, valid and binding obligation of Progress, constitutes a legal, valid and binding obligation of Duke enforceable against Duke in accordance with its terms, except that such enforcement may be subject to applicable bankruptcy, insolvency, reorganization, moratorium or other similar laws, now or hereafter in effect, relating to creditors' rights generally and to general equitable principles.

(d) <u>No Conflicts; Approvals and Consents</u>.

(i) The execution and delivery of this Agreement by Duke does not, and the performance by Duke of its obligations hereunder and the consummation of the Merger and the other transactions contemplated hereby will not, conflict with, result in a violation or breach of, constitute (with or without notice or lapse of time or both) a default under, result in or give to any person any right of payment or reimbursement, termination, cancellation, modification or acceleration of, or result in the creation or imposition of any Lien upon any of the assets or properties of Duke or any of its subsidiaries or any of the Duke Joint Ventures under, any of the terms, conditions or provisions of (A) subject to the effectiveness of the Duke Charter Amendment, the certificates or articles of incorporation or by-laws (or other comparable organizational documents) of Duke or any of its subsidiaries or any of the Duke Joint Ventures, or (B) subject to the obtaining of Duke Shareholder Approval and the taking of the actions described in paragraph (ii) of this Section 3.02(d), including the Duke Required Statutory Approvals, (x) any laws or orders of any Governmental Authority applicable to Duke or any of its subsidiaries or any of the Duke Joint Ventures or any of their respective assets or properties, or (y) any note, bond, mortgage, security agreement, credit agreement, indenture, license, franchise, permit, concession, contract, lease, obligation or other instrument to which Duke or any of its subsidiaries or any of the Duke Joint Ventures is a party or by which Duke or any of its subsidiaries or any of the Duke Joint Ventures or any of their respective assets or properties is bound, excluding from the foregoing clauses (x) and (y) such items that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke.

(ii) Except for (A) compliance with, and filings under, the HSR Act; (B) the filing with and, to the extent required, the declaration of effectiveness by, the SEC of (1) the Joint Proxy Statement pursuant to the Exchange Act, (2) the Form S-4 and (3) such reports under the Exchange Act as may be required in connection with this Agreement and the transactions contemplated hereby; (C) the filing of documents with various state securities authorities that may be required in connection with the transactions contemplated hereby; (D) such filings with and approvals of the NYSE with respect to the Duke Charter Amendment, if necessary, and to permit the shares of Duke Common Stock that are to be issued pursuant to Article II to be listed on the NYSE; (E) the registration, consents, approvals and notices required under the 2005 Act; (F) notice to, and the consent and approval of, FERC under Section 203 of the Power Act, or an order under the Power Act disclaiming jurisdiction over the transactions contemplated hereby; (G) the filing of an application to, and consent and approval of, and issuance of any required licenses and license amendments by, the NRC under the Atomic Energy Act; (H) the filing of the Certificate of Amendment with respect to the Duke Charter Amendment with the Secretary of State of the State of Delaware and the Articles of Merger and other appropriate merger documents required by the NCBCA with the Secretary of State of the State of North Carolina and appropriate documents with the relevant authorities of other states in which Duke is qualified to do business; (I) compliance with and such filings as may be required under applicable Environmental Laws; (J) to the extent required, notice to and the approval of, the Applicable PSCs; (K) the FCC Pre-Approvals; (L) such other items as disclosed in Section 3.02(d) of the Duke Disclosure Letter; and (M) compliance with, and filings under, antitrust or competition laws of any foreign jurisdiction, if required (the items set forth above in clauses (A) through (H) and (J) collectively, the "Duke Required Statutory Approvals"), no Consents or action of, registration, declaration or filing with or notice to any Governmental Authority is necessary or required to be obtained or made in connection with the execution and delivery of this Agreement by Duke, the performance by Duke of its obligations hereunder or the consummation of the Merger and the other transactions contemplated hereby, other than such items that the failure to make or obtain, as the case may be, individually or in the aggregate, could not reasonably be expected to have a material adverse effect on Duke.

(e) SEC Reports, Financial Statements and Utility Reports.

(i) Duke and its subsidiaries have filed or furnished each form, report, schedule, registration statement, registration exemption, if applicable, definitive proxy statement and other document (together with all amendments thereof and supplements thereto) required to be filed or furnished by Duke or any of its subsidiaries pursuant to the Securities Act or the Exchange Act with the SEC since January 1, 2007 (as such documents have since the time of their filing been amended or supplemented, the "Duke SEC Reports"). As of their respective dates, after giving effect to any amendments or supplements thereto, the Duke SEC Reports (A) complied as to form in all material respects with the requirements of the Securities Act and the Exchange Act, if applicable, as the case may be, and, to the extent applicable, SOX and (B) did not contain any untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they were made, not misleading.

(ii) Each of the principal executive officer of Duke and the principal financial officer of Duke (or each former principal executive officer of Duke and each former principal financial officer of Duke, as applicable) has made all certifications required by Rule 13a-14 or 15d-14 under the Exchange Act or Sections 302 and 906 of SOX and the rules and regulations of the SEC promulgated thereunder with respect to the Duke SEC Reports. For purposes of the preceding sentence, "principal executive officer" and "principal financial officer" shall have the meanings given to such terms in SOX. Since January 1, 2007, neither Duke nor any of its subsidiaries has arranged any outstanding "extensions of credit" to directors or executive officers within the meaning of Section 402 of SOX.

(iii) The audited consolidated financial statements and unaudited interim consolidated financial statements (including, in each case, the notes, if any, thereto) included in the Duke SEC Reports (the "Duke Financial Statements") complied as to form in all material respects with the published rules and regulations of the SEC with respect thereto in effect at the time of filing or furnishing the applicable Duke SEC Report, were prepared in accordance with GAAP applied on a consistent basis during the periods involved (except as may be indicated therein or in the notes thereto and except with respect to unaudited statements as permitted by Form 10-Q of the SEC) and fairly present (subject, in the case of the unaudited interim financial statements, to normal, recurring year-end audit adjustments that were not or are not expected to be, individually or in the aggregate, materially adverse to Duke) the consolidated financial position of Duke and its consolidated subsidiaries as of the respective dates thereof and the consolidated results of their operations and cash flows for the respective periods then ended.

(iv) All filings (other than immaterial filings) required to be made by Duke or any of its subsidiaries since January 1, 2007, under the 2005 Act, the Power Act, the Atomic Energy Act, the Natural Gas Act, the Natural Gas Policy Act of 1978, the Communications Act of 1934 and applicable state laws and regulations, have been filed with the SEC, the FERC, the DOE, the NRC, the FCC or any applicable state public utility commissions (including, to the extent required, NCUC, PSCSC, PUCO, IURC and KPSC), as the case may be, including all forms, statements, reports, agreements (oral or written) and all documents, exhibits, amendments and supplements appertaining thereto, including all rates, tariffs, franchises, service agreements and related documents, and all such filings complied, as of their respective dates, with all applicable requirements of the applicable statute and the rules and regulations thereunder, except for filings the failure of which to make or the failure of which to make in compliance with all applicable requirements of the applicable statute and the rules and regulations thereunder, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke.

(v) Duke has designed and maintains a system of internal control over financial reporting (as defined in Rules 13a–15(f) and 15d–15(f) of the Exchange Act) sufficient to provide reasonable assurances regarding the reliability of financial reporting. Duke (x) has designed and maintains disclosure controls and procedures (as defined in Rules 13a–15(e) and 15d–15(e) of the Exchange Act) to provide reasonable assurance that all information required to be disclosed by Duke in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and is accumulated and communicated to Duke's management as appropriate to allow timely decisions regarding required disclosure, and (y) has disclosed, based on its most recent evaluation of internal control over financial reporting , to Duke's outside auditors and the audit committee of the Board of Directors of Duke (A) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect Duke's ability to record, process, summarize and report financial information and (B) any fraud, whether or not material, that involves management or other employees who have a significant role in Duke's internal control over financial reporting. Since December 31, 2006, any material change in internal control over financial reporting required to be disclosed in any Duke SEC Report has been so disclosed.

(vi) Since December 31, 2006, (x) neither Duke nor any of its subsidiaries nor, to the knowledge of the Executive Officers (for the purposes of this Section 3.02(e)(vi), as such term is defined in Section 3b-7 of the Exchange Act) of Duke, any director, officer, employee, auditor, accountant or representative of Duke or any of its subsidiaries has received or otherwise obtained knowledge of any material complaint, allegation, assertion or claim, whether written or oral, regarding the accounting or auditing practices, procedures, methodologies or methods of Duke or any of its subsidiaries or their respective internal accounting controls relating to periods after December 31, 2006, including any material complaint, allegation, assertion or claim that Duke or any of its subsidiaries has engaged in questionable accounting or auditing practices (except for any of the foregoing after the date hereof which have no reasonable basis), and (y) to the knowledge of the Executive Officers of Duke, no attorney representing Duke or any of its subsidiaries, whether or not employed by Duke or any of its subsidiaries, has reported evidence of a material violation of securities laws, breach of fiduciary duty or similar violation, relating to periods after December 31, 2006, by Duke or any of its officers, directors, employees or agents to the Board of Directors of Duke or any committee thereof or, to any director or Executive Officer of Duke.

(f) Absence of Certain Changes or Events. Since December 31, 2009 through the date hereof, Duke and its subsidiaries have conducted their respective businesses in all material respects in the ordinary course of business in a consistent manner since such date and there has not been any change, event or development that, individually or in the aggregate, has had or could reasonably be expected to have a material adverse effect on Duke.

(g) Absence of Undisclosed Liabilities. Except for matters reflected or reserved against in the consolidated balance sheet (or notes thereto) as of December 31, 2009, included in the Duke Financial Statements, neither Duke nor any of its subsidiaries has any liabilities or obligations (whether absolute, accrued, contingent, fixed or otherwise, or whether due or to become due) of any nature that would be required by GAAP to be reflected on a consolidated balance sheet of Duke and its consolidated subsidiaries (including the notes thereto), except liabilities or obligations (i) that were incurred in the ordinary course of business consistent with past practice since December 31, 2009, (ii) that were incurred in connection with the transactions contemplated by this Agreement and that are not material in the aggregate or (iii) that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke. Neither Duke nor any of its subsidiaries is a party to, or has any commitment to become a party to, any joint venture, off-balance sheet partnership or any similar contract or arrangement (including any Contract relating to any transaction or relationship between or among Duke and any of its subsidiaries, on the one hand, and any unconsolidated affiliate, including any structured finance, special purpose or limited purpose entity or person, on the other hand, or any "off-balance sheet arrangements" (as defined in Item 303(a) of Regulation S-K under the Exchange Act), where the result, purpose or effect of such contract or arrangement is to avoid disclosure of any material transaction involving, or material liabilities of, Duke or any of its subsidiaries, in the Duke Financial Statements or the Duke SEC Reports.

(h) Legal Proceedings. Except for Environmental Claims, which are the subject of Section 3.02(n), as of the date of this Agreement, (i) there are no actions, suits, arbitrations or proceedings pending or, to the knowledge of Duke, threatened against, relating to or affecting, nor to the knowledge of Duke are there any Governmental Authority investigations, inquiries or audits pending or threatened against, relating to or affecting, Duke or any of its subsidiaries or any of the Duke Joint Ventures or any of their respective assets and properties that, in each case, individually or in the aggregate, have had or could reasonably be expected to have a material adverse effect on Duke and (ii) neither Duke nor any of its subsidiaries or material assets is subject to any order of any Governmental Authority that, individually or in the aggregate, has had or could reasonably be expected to have a material adverse effect on Duke.

(i) Information Supplied. None of the information supplied or to be supplied by Duke for inclusion or incorporation by reference in (i) the Form S-4 will, at the time the Form S-4 is filed with the SEC, at any time it is amended or supplemented or at the time it becomes effective under the Securities Act, contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary to make the statements therein not misleading, or (ii) the Joint Proxy Statement will, at the date it is first mailed to Progress's shareholders or Duke's shareholders or at the time of the Progress Shareholders Meeting or the Duke Shareholders Meeting, contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements therein, in light of the circumstances under which they are made, not misleading. The Joint Proxy Statement (other than the portions thereof relating solely to the Progress Shareholders Meeting) and the Form S-4 will comply as to form in all material respects with the requirements of the Exchange Act and Securities Act, respectively, and the rules and regulations thereunder, except that no representation is made by Duke with respect to statements made or incorporated by reference therein based on information supplied by or on behalf of Progress for inclusion or incorporation by reference in the Joint Proxy Statement or the Form S-4.

(j) Permits; Compliance with Laws and Orders. Duke, its subsidiaries and the Duke Joint Ventures hold all Permits necessary for the lawful conduct of their respective businesses, except for failures to hold such Permits that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke. Duke, its subsidiaries and the Duke Joint Ventures are in compliance with the terms of their Permits, except failures so to comply that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke. Duke, its subsidiaries and the Duke Joint Ventures are not, and since January 1, 2008 have not been, in violation of or default under any law or order of any Governmental Authority, except for such violations or defaults that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke. Duke is, and since January 1, 2008 has been, in compliance in all material respects with (i) SOX and (ii) the applicable listing standards and corporate governance rules and regulations of the NYSE. The above provisions of this Section 3.02(j) do not relate to matters with respect to taxes, such matters being the subject of Section 3.02(k), Environmental Permits and Environmental Laws, such matters being the subject of Section 3.02(n), benefits plans, such matters being the subject of Section 3.02(l), and nuclear power plants, such matters being the subject of Section 3.02(o).

(k) Taxes.

(i) Except as has not had, and could not reasonably be expected to have, a material adverse effect on Duke:

(A) Each of Duke and its subsidiaries has timely filed, or has caused to be timely filed on its behalf, all Tax Returns required to be filed by it, and all such Tax Returns are true, complete and accurate. All Taxes shown to be due and owing on such Tax Returns have been timely paid.

(B) The most recent financial statements contained in the Duke SEC Reports filed prior to the date of this Agreement reflect, in accordance with GAAP, an adequate reserve for all Taxes payable by Duke and its subsidiaries for all taxable periods through the date of such financial statements.

(C) There is no audit, examination, deficiency, refund litigation, proposed adjustment or matter in controversy with respect to any Taxes or Tax Return of Duke or its subsidiaries, and, to the knowledge of Duke, neither Duke nor any of its subsidiaries has received written notice of any claim made by a governmental authority in a jurisdiction where Duke or any of its subsidiaries, as applicable, does not file a Tax Return, that Duke or such subsidiary is or may be subject to income taxation by that jurisdiction. No deficiency with respect to any Taxes has been proposed, asserted or assessed against Duke or any of its subsidiaries, and no requests for waivers of the time to assess any Taxes are pending.

(D) There are no outstanding written agreements, consents or waivers to extend the statutory period of limitations applicable to the assessment of any Taxes or deficiencies against Duke or any of its subsidiaries, and no power of attorney granted by either Duke or any of its subsidiaries with respect to any Taxes is currently in force.

(E) Neither Duke nor any of its subsidiaries is a party to any agreement providing for the allocation or sharing of Taxes imposed on or with respect to any individual or other person (other than (I) such agreements with customers, vendors, lessors or the like entered into in the ordinary course of business, and (II) agreements with or among Duke or any of its subsidiaries), and neither Duke nor any of its subsidiaries (A) has been a member of an affiliated group (or similar state, local or foreign filing group) filing a consolidated U.S. federal income Tax Return (other than the group the common parent of which is Duke or a subsidiary of Duke) or (B) has any liability for the Taxes of any person (other than Duke or any of its subsidiaries) (I) under Treasury Regulation Section 1.1502-6 (or any similar provision of state, local or foreign law), or (II) as a transferee or successor.

(F) There are no material Liens for Taxes (other than for current Taxes not yet due and payable) on the assets of Duke and its subsidiaries.

(ii) Neither Duke nor any of its subsidiaries has taken or agreed to take any action or knows of any fact, agreement, plan or other circumstance that is reasonably likely to prevent or impede the Merger from qualifying as a reorganization under Section 368(a) of the Code.

(l) Employee Benefit Plans; ERISA.

(i) Except for such matters that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke, (A) all Duke Employee Benefit Plans are in compliance with all applicable requirements of law, including

ERISA and the Code, and (B) there does not now exist, nor do any circumstances exist that could result in, any Controlled Group Liability that would be a liability of Duke or any of its subsidiaries following the Closing. The only material employment agreements, severance agreements or severance policies applicable to Duke or any of its subsidiaries are the agreements and policies disclosed in Section 3.02(l)(i) of the Duke Disclosure Letter.

(ii) As used herein, "Duke Employee Benefit Plan" means any Plan entered into, established, maintained, sponsored, contributed to or required to be contributed to by Duke or any of its subsidiaries for the benefit of the current or former employees or directors of Duke or any of its subsidiaries and existing on the date of this Agreement or at any time subsequent thereto and, in the case of a Plan that is subject to Part 3 of Title I of ERISA, Section 412 of the Code or Title IV of ERISA, at any time during the five-year period preceding the date of this Agreement with respect to which Duke or any of its subsidiaries has or could reasonably be expected to have any present or future actual or contingent liabilities.

(iii) No event has occurred, and there exists no condition or set of circumstances in connection with any Duke Employee Benefit Plan, that has had or could reasonably be expected to have a material adverse effect on Duke.

(iv) Section 3.02(l)(iv) of the Duke Disclosure Letter identifies each Duke Employee Benefit Plan that provides, upon the occurrence of a change in the ownership or effective control of Duke or its subsidiaries or a change in the ownership of all or a substantial portion of the assets of Duke or its subsidiaries, either alone or upon the occurrence of any additional or subsequent events and whether or not applicable to the transactions contemplated by this Agreement, for (A) an acceleration of the time of payment of or vesting in, or an increase in the amount of, compensation or benefits due any current or former employee, director or officer of Duke or its subsidiaries, (B) any forgiveness of indebtedness or obligation to fund compensation or benefits with respect to any such employee, director or officer, or (C) an entitlement of any such employee, director or officer to severance pay, unemployment compensation or any other payment or other benefit.

(v) Each Duke Employee Benefit Plan that is in any part a "nonqualified deferred compensation plan" subject to Section 409A of the Code (A) materially complies and, at all times after December 31, 2008 has materially complied, both in form and operation, with the requirements of Section 409A of the Code and the final regulations thereunder and (B) between January 1, 2005 and December 31, 2008 was operated in material reasonable, good faith compliance with Section 409A of the Code, as determined under applicable guidance of the Treasury and the Internal Revenue Service.

(m) Labor Matters. As of the date hereof, neither Duke nor any of its subsidiaries is a party to, bound by or in the process of negotiating any collective bargaining agreement or other labor agreement with any union or labor organization. As of the date of this Agreement, there are no disputes, grievances or arbitrations pending or, to the knowledge of Duke, threatened between Duke or any of its subsidiaries and any trade union or other representatives of its employees and there is no charge or complaint pending or threatened in writing against Duke or any of its subsidiaries before the NLRB or any similar Governmental Authority, except in each case as, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke, and, to the knowledge of Duke, as of the date of this Agreement, there are no material organizational efforts presently being made involving any of the employees of Duke or any of its subsidiaries. From December 31, 2007, to the date of this Agreement, there has been no work stoppage, strike, slowdown or lockout by or affecting employees of Duke or any of its subsidiaries and, to the knowledge of Duke, no such action has been threatened in writing, except in each case as, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke. Except as, individually or in the aggregate, has not had and could not reasonably be expected to have a material adverse effect on Duke: (A) there are no litigations, lawsuits, claims, charges, complaints, arbitrations, actions, investigations or proceedings pending or, to the knowledge of Duke, threatened between or involving Duke or any of its subsidiaries and any of their respective current or former employees, independent contractors, applicants for employment or classes of the foregoing; (B) Duke and its subsidiaries are in compliance with all applicable laws, orders, agreements, contracts and policies respecting employment and employment practices, including, without limitation, all legal requirements respecting terms and conditions of employment, equal opportunity, workplace health and safety, wages and hours, child labor, immigration, discrimination, disability rights or benefits, facility closures and layoffs, workers' compensation, labor relations, employee leaves and unemployment insurance; and (C) since January 1, 2007, neither Duke nor any of its subsidiaries has engaged in any "plant closing" or "mass layoff," as defined in the WARN Act, without complying with the notice requirements of such laws.

(n) <u>Environmental Matters</u>.

(i) Each of Duke, its subsidiaries and the Duke Joint Ventures since January 1, 2008 has been and is in compliance with all applicable Environmental Laws, except where the failure to be in such compliance, individually or in the aggregate, has not had and could not reasonably be expected to have a material adverse effect on Duke.

(ii) Each of Duke, its subsidiaries and the Duke Joint Ventures has obtained all Environmental Permits necessary for the construction of their facilities and the conduct of their operations as of the date of this Agreement, as applicable, and all such Environmental Permits are validly issued, in full force and effect and final, and Duke, its subsidiaries and the Duke Joint Ventures are in compliance with all terms and conditions of the Environmental Permits, except where the failure to obtain such Environmental Permits, of such Permits to be in good standing or, where applicable, of a renewal application to have been timely filed and be pending or to be in such compliance, individually or in the aggregate, has not had and could not reasonably be expected to have a material adverse effect on Duke.

(iii) There is no Environmental Claim pending

(A) against Duke or any of its subsidiaries or any of the Duke Joint Ventures;

(B) to the knowledge of Duke, against any person or entity whose liability for such Environmental Claim has been retained or assumed either contractually or by operation of law by Duke or any of its subsidiaries or any of the Duke Joint Ventures; or

(C) against any real or personal property or operations that Duke or any of its subsidiaries or any of the Duke Joint Ventures owns, leases or manages, in whole or in part, or, to the knowledge of Duke, formerly owned, leased or arranged, in whole or in part, except in the case of clause (A), (B) or (C) for such Environmental Claims that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke.

(iv) To the knowledge of Duke, there have not been any Releases of any Hazardous Material that would be reasonably likely to form the basis of any Environmental Claim against Duke or any of its subsidiaries or any of the Duke Joint Ventures, in each case, except for such Releases that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke.

(o) Operations of Nuclear Power Plants. The operations of the nuclear generation stations owned, in whole or part, by Duke or its subsidiaries (collectively, the "Duke Nuclear Facilities") are and have been conducted in compliance with all applicable laws and Permits, except for such failures to comply that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke. Each of the Duke Nuclear Facilities maintains, and is in material compliance with, emergency plans designed to respond to an unplanned Release therefrom of radioactive materials and each such plan conforms with the requirements of applicable law in all material respects. The plans for the decommissioning of each of the Duke Nuclear Facilities and for the storage of spent nuclear fuel conform with the requirements of applicable law in all material respects and, solely with respect to the portion of the Duke Nuclear Facilities owned, directly or indirectly, by Duke, are funded consistent with applicable law. Since December 31, 2008, the operations of the Duke Nuclear Facilities have not been the subject of any notices of violation, any ongoing proceeding, NRC Diagnostic Team Inspections or requests for information from the NRC or any other agency with jurisdiction over such facility, except for such notices or requests for information that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke. No Duke Nuclear Facility is listed by the NRC in the Unacceptable Performance column of the NRC Action Matrix, as a part of NRC's Assessment of Licensee Performance. Liability insurance to the full extent required by law for operating the Duke Nuclear Facilities remains in full force and effect regarding such facilities, except for failures to maintain such insurance in full force and effect that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke.

(p) Vote Required. Assuming the accuracy of the representation and warranty contained in Section 3.01(r), the affirmative vote of the holders of record of at least a majority of the shares of Duke Common Stock (i) outstanding, with respect to an amendment to the Amended and Restated Certificate of Incorporation of Duke providing for the Duke Charter Amendment and (ii) voting thereon, provided that the total vote cast represents over fifty percent in interest of all securities entitled to vote on the proposal, with respect to the issuance of shares of Duke Common Stock in connection with the Merger as contemplated by this Agreement (the "Duke Share Issuance") ((i) and (ii) collectively, the "Duke Shareholder Approval"), are the only votes of the holders of any class or series of the capital stock of Duke or its subsidiaries required to approve this Agreement, the Merger and the other transactions contemplated hereby.

(q) Opinions of Financial Advisors. The Board of Directors of Duke has received the opinion of each of J.P. Morgan Securities LLC and Merrill Lynch, Pierce, Fenner and Smith Incorporated, to the effect that, as of the date of such opinion and based on the assumptions, qualifications and limitations contained therein, the Exchange Ratio is fair, from a financial point of view, to Duke.

(r) Ownership of Progress Capital Stock. Neither Duke nor any of its subsidiaries or other affiliates beneficially owns any shares of Progress capital stock.

(s) Certain Statutes. No "fair price," "merger moratorium," "control share acquisition," or other anti-takeover or similar statute or regulation applies or purports to apply to this Agreement, the Merger or the other transactions contemplated hereby.

(t) Joint Venture Representations. Each representation or warranty made by Duke in this Section 3.02 relating to a Duke Joint Venture that is neither operated nor managed solely by Duke or a Duke subsidiary shall be deemed made only to the knowledge of Duke.

(u) Insurance. Except for failures to maintain insurance or self-insurance that, individually or in the aggregate, have not had and could not reasonably be expected to have a material adverse effect on Duke, from January 1, 2007, through the date of this Agreement, each of Duke and its subsidiaries has been continuously insured with financially responsible insurers or has self-insured, in each case in such amounts and with respect to such risks and losses as are customary for companies in the United States conducting the business conducted by Duke and its subsidiaries during such time period. Neither Duke nor any of its subsidiaries has received any notice of any pending or threatened cancellation, termination or premium increase with respect to any insurance policy of Duke or any of its subsidiaries, except with respect to any cancellation, termination or premium increase that, individually or in the aggregate, has not had and could not reasonably be expected to have a material adverse effect on Duke.

(v) Energy Price Risk Management. Duke has established risk parameters, limits and guidelines in compliance with the risk management policy approved by Duke's Board of Directors (the "Duke Risk Management Guidelines") and monitors compliance by Duke and its subsidiaries with such energy price risk parameters. Duke has provided the Duke Risk Management Guidelines to Progress prior to the date of this Agreement. Duke is in compliance in all material respects with the Duke Risk Management Guidelines.

(w) Duke Material Contracts.

(i) For purposes of this Agreement, the term "Duke Material Contract" shall mean any Contract to which Duke or any of its subsidiaries is a party or bound as of the date hereof:

(A) that is a "material contract" (as such term is defined in Item 601(b)(10) of Regulation S-K of the SEC);

(B) that (1) purports to limit in any material respect either the type of business in which Duke or its subsidiaries (including, after the Effective Time, Progress or its subsidiaries) or any of their respective affiliates may engage or the manner or geographic area in which any of them may so engage in any business, (2) would require the disposition of any material assets or line of business of Duke or its subsidiaries (including, after the Effective Time, Progress or its subsidiaries) or any of their respective affiliates as a result of the consummation of the transactions contemplated by this Agreement, (3) is a material Contract that grants "most favored nation" status that, following the Effective Time, would impose obligations upon Duke or its subsidiaries, including Progress and its subsidiaries, or (4) prohibits or limits, in any material respect, the right of Duke or any of its subsidiaries (including, after the Effective Time, Progress or its subsidiaries) to make, sell or distribute any products or services or use, transfer, license or enforce any of their respective intellectual property rights; or

(C) that (1) has an aggregate principal amount, or provides for an aggregate obligation, in excess of $200,000,000 (I) evidencing indebtedness for borrowed money of Duke or any of its subsidiaries to any third party, (II) guaranteeing any such indebtedness of a third party or (III) containing a covenant restricting the payment of dividends, or (2) has the economic effect of any of the items set forth in subclause (1) above.

(ii) Neither Duke nor any subsidiary of Duke is in breach of or default under the terms of any Duke Material Contract and no event has occurred that (with or without notice or lapse of time or both) could result in a breach or default under any Duke Material Contract where such breach or default could reasonably be expected to have, individually or in the aggregate, a material adverse effect on Duke. To the knowledge of Duke, no other party to any Duke Material Contract is in breach of or default under the terms of any Duke Material Contract where such breach or default has had, or could reasonably be expected to have, individually or in the aggregate, a material adverse effect on Duke. Except as could not reasonably be expected to have, individually or in the aggregate, a material adverse effect on Duke, each Duke Material Contract is a valid and binding obligation of Duke or the subsidiary of Duke which is party thereto and, to the knowledge of Duke, of each other party thereto, and is in full force and effect, except that such enforcement may be subject to applicable bankruptcy, insolvency, reorganization, moratorium or other similar laws, now or hereafter in effect, relating to creditors' rights generally and to general equitable principles.

(x) Anti-Bribery Laws.

(i) To the knowledge of Duke, Duke and its subsidiaries are, and since January 1, 2008 have been, in compliance in all material respects with the Anti-Bribery Laws in jurisdictions in which Duke and its subsidiaries have operated or currently operate. Since January 1, 2008, neither Duke nor any of its subsidiaries has received any communication from any Governmental Authority or any written communication from any third party that alleges that Duke, any of its subsidiaries or any employee or agent thereof is in material violation of any Anti-Bribery Laws, and no such potential or actual material violation or liability has been discovered.

(ii) Without limiting the other provisions of this Section 3.02(x), since January 1, 2008, none of Duke or its subsidiaries nor, to the knowledge of Duke, any of their respective current or former directors, officers, principals, employees, managers, sales persons, consultants or other agents or representatives, distributors, contractors, joint venturers or any other person acting on any of their behalf, has, directly or indirectly, made or offered or solicited or accepted any contribution, gift, gratuity, entertainment, bribe, rebate, payoff, influence payment, kickback or other payment or anything else of value to or from any person, private or public (including customers, potential customers, political parties, elected officials and candidates), whether in money, property, services or any other form, to influence any act of such person in such person's official capacity, inducing such person to do or omit to do any act in violation of the lawful official duty of such person or securing an improper advantage or to induce such person to use such person's influence to obtain or retain business for Duke or its subsidiaries or otherwise to confer any benefit to Duke or its subsidiaries in violation in any material respect of any Anti-Bribery Laws.

(iii) Since January 1, 2006, neither Duke nor any of its subsidiaries has made any disclosure (voluntary or otherwise) to any Governmental Authority with respect to any alleged material irregularity, material misstatement or material omission or other potential material violation or liability arising under or relating to any Anti-Bribery Law.

ARTICLE IV

COVENANTS

Section 4.01 Covenants of Progress. From and after the date of this Agreement until the Effective Time, Progress covenants and agrees as to itself and its subsidiaries that (except as expressly contemplated or permitted by this Agreement, as set forth in Section 4.01 of the Progress Disclosure Letter, for transactions (other than those set forth in Section 4.01(d) to the extent relating to the capital stock of Progress) solely involving Progress and one or more of its direct or indirect wholly-owned subsidiaries or between two or more direct or indirect wholly-owned subsidiaries of Progress, as required by law, or to the extent that Duke shall otherwise previously consent in writing, such consent not to be unreasonably withheld or delayed):

(a) Ordinary Course. Progress and each of its subsidiaries shall conduct their businesses in all material respects in the ordinary course of business consistent with past practice. Without limiting the generality of the foregoing, Progress and its subsidiaries shall use commercially reasonable efforts to preserve intact in all material respects their present business organizations, to maintain in effect all existing Permits and to timely submit renewal applications (as applicable), subject to prudent management of workforce and business needs, to keep available the services of their key officers and employees, to maintain their assets and properties in good working order and condition, ordinary wear and tear excepted, to preserve their relationships with Governmental Authorities, customers and suppliers and others having significant business dealings with them and to comply in all material respects with all laws, orders and Permits of all Governmental Authorities applicable to them.

(b) Charter Documents. Progress shall not amend or propose to amend its articles of incorporation or, other than in a manner that would not materially restrict the operation of its or their businesses, its by-laws or its subsidiaries' articles of incorporation or by-laws (or other comparable organizational documents).

(c) Dividends. Progress shall not, nor shall it permit any of its subsidiaries to,

(i) declare, set aside or pay any dividends on or make other distributions in respect of any of its capital stock or share capital, except:

(A) that, subject to Section 4.06 of this Agreement, Progress may continue the declaration and payment of regular quarterly cash dividends on Progress Common Stock, not to exceed $0.62 per share for each quarterly dividend, with usual record and payment dates for such dividends in accordance with past dividend practice, and

(B) for the declaration and payment of dividends by a direct or indirect wholly-owned subsidiary of Progress solely to its parent, or by a direct or indirect partially owned subsidiary of Progress (provided, that Progress or a Progress subsidiary receives or is to receive its proportionate share of such dividend or distribution), and

(C) for the declaration and payment of regular cash dividends with respect to preferred stock of Progress's subsidiaries outstanding as of the date of this Agreement or permitted to be issued under the terms of this Agreement, and

(D) for the declaration and payment of dividends necessary to comply with Section 4.06,

(ii) split, combine, reclassify or take similar action with respect to any of its capital stock or share capital or issue or authorize or propose the issuance of any other securities in respect of, in lieu of or in substitution for shares of its capital stock or comprised in its share capital,

(iii) adopt a plan of complete or partial liquidation or resolutions providing for or authorizing such liquidation or a dissolution, merger, consolidation, restructuring, recapitalization or other reorganization, or

(iv) except as disclosed in Section 4.01(c)(iv) of the Progress Disclosure Letter, directly or indirectly redeem, repurchase or otherwise acquire any shares of its capital stock or any Option with respect thereto except:

(A) in connection with intercompany purchases of capital stock or share capital, or

(B) for the purpose of funding the Progress Employee Stock Option Plans or employee stock ownership or dividend reinvestment and stock purchase plans, or

(C) mandatory repurchases or redemptions of preferred stock of Progress or its subsidiaries in accordance with the terms thereof.

(d) Share Issuances. Progress shall not, nor shall it permit any of its subsidiaries to, issue, deliver or sell, or authorize or propose the issuance, delivery or sale of, any shares of its capital stock or any Option with respect thereto (other than (i) the issuance of Progress Common Stock upon the exercise of Progress Employee Stock Options outstanding as of the date hereof or issued after the date hereof in accordance with the terms of this Agreement in accordance with their terms, (ii) the issuance of Progress Common Stock in respect of Progress Restricted Stock, Progress Restricted Stock Units, Progress Performance Shares and other equity compensation awards, excluding Progress Employee Stock Options, granted under the Progress Employee Stock Option Plans ("Other Progress Equity Awards") outstanding as of the date hereof or issued after the date hereof in accordance with the terms of this Agreement in accordance with their terms, (iii) the issuance of Progress Restricted Stock, Progress Performance Shares and the grant of Progress Restricted Stock Units and Other Progress Equity Awards in accordance with their terms providing, in aggregate, up to an additional 2,000,000 shares of Progress Common Stock in any 12-month period following the date hereof, in amounts, at times and on terms and conditions in the ordinary course of business consistent with past practice, with Progress Performance Shares counted assuming the achievement of maximum performance level for the purposes of determining how many shares were granted during any such 12-month period; provided, however, that any Progress Restricted Stock, Progress Restricted Stock Units, Progress Performance Shares and Other Progress Equity Awards granted after the date of this Agreement shall be granted on terms pursuant to which such Progress Restricted Stock, Progress Restricted Stock Units, Progress Performance Shares and Other Progress Equity Awards shall not vest on the Effective Time or otherwise in connection with the occurrence of the transactions contemplated hereby and that, notwithstanding any plan, program or arrangement to the contrary, and except as provided in Section 4.01(d)(iii) of the Progress Disclosure Letter, any definition of "good reason" or any similar concept of constructive termination relating to such awards shall be as defined in Section 4.01(d)(iii) of the Progress Disclosure Letter and the terms and conditions of each grant of Progress Performance Shares shall be consistent with the treatment set forth in Section 5.06(a)(iii), (iv) the *pro rata* issuance by a subsidiary of its capital stock to its shareholders, and (v) the issuance of shares of Progress Common Stock in connection with any employee benefit plan intended to satisfy the requirements of Section 401(a) of the Code in the ordinary course of business consistent with past practice), or modify or amend any right of any holder of outstanding shares of its capital stock or any Option with respect thereto other than to give effect to Section 5.06.

(e) Acquisitions; Capital Expenditures. Except for (x) acquisitions of, or capital expenditures relating to, the entities, assets and facilities identified in Section 4.01(e) of the Progress Disclosure Letter, (y) expenditures of amounts set forth in Progress's capital expenditure plan included in Section 4.01(e) of the Progress Disclosure Letter, and (z) capital expenditures (1) required by law or Governmental Authorities or (2) incurred in connection with the repair or replacement of facilities destroyed or damaged due to casualty or accident (whether or not covered by insurance), Progress shall not, nor shall it permit any of its subsidiaries to, make any capital expenditures, or acquire or agree to acquire (whether by merger, consolidation, purchase or otherwise) any person or assets, if (A) in the case of any acquisition or acquisitions or series of related acquisitions of any person, asset or property located within the United States, the expected gross expenditures and commitments pursuant to all such acquisitions (including the amount of any indebtedness and amounts received for negative trading positions assumed) exceeds or may exceed, in the aggregate, $150,000,000, (B) any such acquisition is of persons, properties or assets located outside of the United States, (C) any such acquisition or capital expenditure constitutes any line of business that is not conducted by Progress, its subsidiaries or the Progress Joint Ventures as of the date of this Agreement, or (D) any such acquisition or capital expenditure is reasonably likely, individually or in the aggregate, to materially delay the satisfaction of the conditions set forth in Section 6.02(d) or Section 6.03(d) or prevent the satisfaction of such conditions.

(f) Dispositions. Except for (x) dispositions set forth in Section 4.01(f) of the Progress Disclosure Letter, (y) dispositions of obsolete equipment or assets or dispositions of assets being replaced, in each case in the ordinary course of business consistent with past practice, and (z) dispositions by Progress or its subsidiaries of its assets in accordance with the terms of restructuring and divestiture plans mandated or approved by applicable local or state regulatory agencies, Progress shall not, nor shall it permit any of its subsidiaries to, sell, lease, grant any security interest in or otherwise dispose of or encumber any of its assets or properties if the aggregate value of all such dispositions exceeds or may exceed, in the aggregate, $150,000,000. For the purposes of this Section 4.01(f), the value of any disposition or series of related dispositions shall mean the greater of (i) the book value or (ii) the sales price, in each case of the person, asset or property which is the subject of such disposition and, in each case, together with the indebtedness and amounts paid for negative energy price risk management positions transferred by Progress or its subsidiaries in connection with such disposition.

(g) Indebtedness. Except as disclosed in Section 4.01(g) of the Progress Disclosure Letter, Progress shall not, nor shall it permit any of its subsidiaries to, (A) incur or guarantee any indebtedness or enter into any "keep well" or other agreement to maintain any financial condition of another person or enter into any arrangement having the economic effect of any of the foregoing (including any capital leases, "synthetic" leases or conditional sale or other title retention agreements) other than (i) short-term indebtedness incurred in the ordinary course of business, (ii) letters of credit obtained in the ordinary course of business, (iii) borrowings under Progress's or its subsidiaries' existing credit facilities (or replacement facilities permitted by this Section 4.01(g)) but only to the extent the commercial paper market is unavailable to Progress upon reasonable terms and conditions, as to which borrowings Progress agrees to notify Duke promptly following the consummation thereof, (iv) indebtedness incurred in connection with the refunding or refinancing of existing indebtedness (x) at maturity or upon final mandatory redemption (without the need for the occurrence of any special event) or (y) at a lower cost of funds, (v) indebtedness incurred to finance acquisitions permitted pursuant to Section 4.01(e) or indebtedness assumed pursuant thereto, (vi) other indebtedness in an aggregate principal amount not to exceed $250,000,000 outstanding at any time, (vii) guarantees or other credit support issued pursuant to energy price risk management or marketing positions established prior to the date of this Agreement, (viii) in addition to the guarantees or other credit support contemplated by subsection (A)(vii) of this Section 4.01(g), additional guarantees or other credit support issued in connection with energy price risk management or marketing activities in the ordinary course of business and (ix) indebtedness owed to any direct or indirect wholly-owned subsidiary of Progress, or, in the case of a subsidiary of Progress, to Progress or (B) make any loans or advances to any other person, other than (i) in the ordinary course of business consistent with past practice, (ii) to any direct or indirect wholly-owned subsidiary of Progress, or, in the case of a subsidiary of Progress, to Progress or (iii) as required pursuant to any obligation in effect as of the date of this Agreement.

(h) Marketing of Energy; Energy Price Risk Management. Progress shall not, nor shall it permit any of its subsidiaries to, (i) permit any material change in policies governing or otherwise relating to energy price risk management or marketing of energy other than as a result of acquisitions or capital expenditures permitted pursuant to Section 4.01(e) or (ii) enter into any physical commodity transactions, exchange-traded futures and options transactions, over-the-counter transactions and derivatives thereof or similar transactions other than as permitted by the Progress Risk Management Guidelines.

(i) Employee Benefits. Except as required by law, or the terms of any collective bargaining agreement or any Progress Employee Benefit Plan, or as disclosed in Section 4.01(i) of the Progress Disclosure Letter or as otherwise expressly permitted by this Agreement, Progress shall not, nor shall it permit any of its subsidiaries to, enter into, adopt, amend or terminate any Progress Employee Benefit Plan, or other agreement, arrangement, plan or policy between Progress or one of its subsidiaries and one or more of its directors, officers or employees (other than any amendment that is immaterial or administrative in nature), or, except for normal increases in the ordinary course of business consistent with past practice, increase in any manner the compensation or fringe benefits of any director, executive officer or other employee, or, except for normal payments in the ordinary course of business consistent with past practice, and the award of annual bonuses on terms and conditions that are consistent with Section 5.07(g), pay any benefit not required by any plan or arrangement in effect as of the date of this Agreement; provided, however, that the foregoing shall not restrict Progress or its subsidiaries from (i) entering into or making available to newly hired officers and employees or to officers and employees in the context of promotions based on job performance or workplace requirements in the ordinary course of business consistent with past practice, plans, agreements, benefits and compensation arrangements (including incentive grants) that have, consistent with past practice, been made available to newly hired or promoted officers and employees, (ii) entering into severance agreements with, or adopting severance plans in the ordinary course of business consistent with past practice for, employees who are not executive officers in connection with terminations of employment of such employees, or (iii) entering into or amending collective bargaining agreements with existing collective bargaining representatives or newly certified bargaining units regarding mandatory subjects of bargaining under applicable law, in each case in a manner consistent with past practice to the extent permitted by law.

(j) [Intentionally Reserved.]

(k) Accounting. Progress shall not, nor shall it permit any of its subsidiaries to, make any changes in its accounting methods materially affecting the reported consolidated assets, liabilities or results of operations of Progress, except as required by law or GAAP.

(l) Insurance. Progress shall, and shall cause its subsidiaries to, maintain with financially responsible insurance companies (or through self-insurance, consistent with past practice) insurance in such amounts and against such risks and losses as are customary for companies engaged in their respective businesses, to the extent available on commercially reasonable terms.

(m) Taxes. Except as could not reasonably be expected to have a material adverse effect on Progress, Progress shall not, nor shall it permit any of its subsidiaries to, (i) settle any claim, action or proceeding relating to Taxes or (ii) make any Tax election (this clause (m) being the sole provision of this Section 4.01 governing Tax matters).

(n) Release of Claims. Except as disclosed in Section 4.01(n) of the Progress Disclosure Letter and except with respect to any settlements or agreements with or before any Governmental Authorities in the ordinary course of business, Progress shall not, and shall not permit any of its subsidiaries to, waive, release, assign, settle or compromise any claim, action or proceeding against Progress or any of its subsidiaries, other than waivers, releases, assignments, settlements or compromises that (x) with respect to the payment of monetary damages, involve only the payment of monetary damages (A) equal to or less than the amounts specifically reserved with respect thereto on the balance sheet as of December 31, 2009 included in the Progress SEC Documents or (B) that do not exceed $15,000,000 individually or $50,000,000 in the aggregate during any consecutive twelve-month period, and (y) with respect to any non-monetary terms and conditions therein, impose or require actions that would not reasonably be expected individually or in the aggregate to have a material adverse effect on Progress.

(o) Contracts. Except as permitted by Section 4.01(i), Progress shall not, nor shall it permit any of its subsidiaries to, (i) enter into any Contract that would materially restrict, after the Effective Time, Duke and its subsidiaries (including the Surviving Corporation and its subsidiaries) with respect to engaging or competing in any line of business or in any geographic area or (ii) other than in the ordinary course of business, waive, release, or assign any material rights or claims under, or materially modify or terminate any Contract that is material to Progress and its subsidiaries, taken as a whole, (A) in any manner that is materially adverse to Progress or (B) which would prevent or materially delay the consummation of the Merger and the other transactions contemplated by this Agreement, it being understood and agreed that the restriction on material modifications and terminations in clause (ii)(A) shall not apply with respect to any Contract permitted to be entered into under clause (e), (f), (g), (h) or (n) of this Section 4.01.

Section 4.02 Covenants of Duke. From and after the date of this Agreement until the Effective Time, Duke covenants and agrees as to itself and its subsidiaries that (except as expressly contemplated or permitted by this Agreement, as set forth in Section 4.02 of the Duke Disclosure Letter, for transactions (other than those set forth in Section 4.02(d) to the extent relating to the capital stock of Duke) solely involving Duke and one or more of its direct or indirect wholly-owned subsidiaries or between two or more direct or indirect wholly-owned subsidiaries of Duke, as required by law, or to the extent that Progress shall otherwise previously consent in writing, such consent not to be unreasonably withheld or delayed):

(a) Ordinary Course. Duke and each of its subsidiaries shall conduct their businesses in all material respects in the ordinary course of business consistent with past practice. Without limiting the generality of the foregoing, Duke and its subsidiaries shall use commercially reasonable efforts to preserve intact in all material respects their present business organizations, to maintain in effect all existing Permits and to timely submit renewal applications (as applicable), subject to prudent management of workforce and business needs, to keep available the services of their key officers and employees, to maintain their assets and properties in good working order and condition, ordinary wear and tear excepted, to preserve their relationships with Governmental Authorities, customers and suppliers and others having significant business dealings with them and to comply in all material respects with all laws, orders and Permits of all Governmental Authorities applicable to them.

(b) Charter Documents. Duke shall not amend or propose to amend its certificate of incorporation other than in connection with the Duke Charter Amendment or, other than in a manner that would not materially restrict the operation of its or their businesses, its by-laws or its subsidiaries' certificates of incorporation or by-laws (or other comparable organizational documents).

(c) Dividends. Duke shall not, nor shall it permit any of its subsidiaries to,

(i) declare, set aside or pay any dividends on or make other distributions in respect of any of its capital stock or share capital, except:

(A) that, subject to Section 4.06 of this Agreement, Duke may continue the declaration and payment of regular quarterly cash dividends on Duke Common Stock not to exceed $0.245 per share for each quarterly dividend, with usual record and payment dates for such dividends in accordance with past dividend practice; provided, that Duke may increase its regular quarterly cash dividend to an amount not to exceed $0.25 commencing with the regular quarterly dividend that would be payable in 2011 with respect to the second quarter of 2011 (corresponding to the dividend paid on September 16, 2010) and to an amount not to exceed $0.255 commencing with the regular quarterly dividend that would be payable in 2012 with respect to the second quarter of 2012 (it being Duke's intention prior to the Effective Time to declare and pay those dividends permitted by this Section 4.02(c)(i)(A) if and to the extent there are funds legally available therefor and such dividends may otherwise lawfully be declared and paid), and

(B) for the declaration and payment of dividends by a direct or indirect wholly-owned subsidiary of Duke solely to its parent, or by a direct or indirect partially owned subsidiary of Duke (provided, that Duke or a Duke subsidiary receives or is to receive its proportionate share of such dividend or distribution), and

(C) for the declaration and payment of dividends necessary to comply with Section 4.06,

(ii) split, combine, reclassify or take similar action with respect to any of its capital stock or share capital or issue or authorize or propose the issuance of any other securities in respect of, in lieu of or in substitution for shares of its capital stock or comprised in its share capital,

(iii) adopt a plan of complete or partial liquidation or resolutions providing for or authorizing such liquidation or a dissolution, merger, consolidation, restructuring, recapitalization or other reorganization,

(iv) except as disclosed in Section 4.02(c)(iv) of the Duke Disclosure Letter directly or indirectly redeem, repurchase or otherwise acquire any shares of its capital stock or any Option with respect thereto except:

(A) in connection with intercompany purchases of capital stock or share capital, or

(B) for the purpose of funding the Duke Employee Stock Option Plan or employee stock ownership or dividend reinvestment and stock purchase plans, or

(v) bind Duke to any restriction not in existence on the date hereof on the payment by Duke of dividends and distributions on Duke Common Stock.

(d) Share Issuances. Duke shall not, nor shall it permit any of its subsidiaries to, issue, deliver or sell, or authorize or propose the issuance, delivery or sale of, any shares of its capital stock or any Option with respect thereto (other than (i) the issuance of Duke Common Stock upon the exercise of Duke Employee Stock Options outstanding as of the date hereof or issued after the date hereof in accordance with the terms of this Agreement in accordance with their terms, (ii) the issuance of Duke Common Stock in respect of Duke Phantom Stock Units, Duke Performance Shares and other equity compensation awards, excluding Duke Employee Stock Options, granted under the Duke Employee Stock Option Plans ("Other Duke Equity Awards") outstanding as of the date hereof or issued after the date hereof in accordance with the terms of this Agreement in accordance with their terms, (iii) the issuance of Duke Employee Stock Options, Duke Performance Shares and the grant of Duke Phantom Stock Units and Other Duke Equity Awards in accordance with their terms providing, in aggregate, up to an additional 6,000,000 shares of Duke Common Stock in any 12-month period following the date hereof, in amounts, at times and on terms and conditions in the ordinary course of business consistent with past practice, with each Duke Employee Stock Option counting as 1/4 of a share of Duke Common Stock and Duke Performance Shares counted assuming the achievement of maximum performance level, in each case for the purposes of determining how many shares were granted during any such 12-month period; provided, however, that any Duke Employee Stock Options, Duke Phantom Stock Units, Duke Performance Shares and Other Duke Equity Awards granted after the date of this Agreement shall be granted on terms pursuant to which such Duke Employee Stock Options, Duke Phantom Stock Units, Duke Performance Shares and Other Duke Equity Awards shall not vest on the Effective Time or otherwise in connection with the occurrence of the transactions contemplated hereby and that, notwithstanding any plan, program or arrangement to the contrary, any definition of "good reason" or any similar concept of constructive termination relating to such awards shall be as defined in Section 4.02(d)(iii) of the Duke Disclosure Letter, (iv) the *pro rata* issuance by a subsidiary of its capital stock to its shareholders and (v) the issuance of shares of Duke Common Stock in connection with any employee benefit plan intended to satisfy the requirements of Section 401(a) of the Code in the ordinary course of business consistent with past practice), or modify or amend any right of any holder of outstanding shares of its capital stock or any Option with respect thereto other than to give effect to Section 5.06.

(e) Acquisitions; Capital Expenditures. Except for (x) acquisitions of, or capital expenditures relating to, the entities, assets and facilities identified in Section 4.02(e) of the Duke Disclosure Letter, (y) expenditures of amounts set forth in Duke's capital expenditure plan included in Section 4.02(e) of the Duke Disclosure Letter, and (z) capital expenditures (1) required by law or Governmental Authorities or (2) incurred in connection with the repair or replacement of facilities destroyed or damaged due to casualty or accident (whether or not covered by insurance), Duke shall not, nor shall it permit any of its subsidiaries to, make any capital expenditures, or acquire or agree to acquire (whether by merger, consolidation, purchase or otherwise) any person or assets, if (A) the expected gross expenditures and commitments pursuant thereto (including the amount of any indebtedness and amounts received for negative energy price risk management positions assumed) exceeds or may exceed $300,000,000 (no more than $150,000,000 of which may be for any acquisition or series of related acquisitions of any person, asset or property located outside of the United States), (B) any such acquisition or capital expenditure constitutes any line of business that is not conducted by Duke, its subsidiaries or the Duke Joint Ventures as of the date of this Agreement or extends any line of business of Duke, its subsidiaries or the Duke Joint Ventures into any geographic region outside of the continental United States or Canada in which Duke, its subsidiaries or the Duke Joint Ventures do not conduct business as of the date of this Agreement, or (C) any such acquisition or capital expenditure is reasonably likely, individually or in the aggregate, to materially delay the satisfaction of the conditions set forth in Section 6.02(d) or Section 6.03(d) or prevent the satisfaction of such conditions.

(f) Dispositions. Except for (x) dispositions set forth in Section 4.02(f) of the Duke Disclosure Letter, (y) dispositions of obsolete equipment or assets or dispositions of assets being replaced, in each case in the ordinary course of business consistent with past practice, and (z) dispositions by Duke or its subsidiaries of its assets in accordance with the terms of restructuring and divestiture plans mandated or approved by applicable local or state regulatory agencies, Duke shall not, nor shall it permit any of its subsidiaries to, sell, lease, grant any security interest in or otherwise dispose of or encumber any of its assets or properties if (A) the aggregate value of all such dispositions exceeds or may exceed $300,000,000 (no more than $150,000,000 of which may be for any disposition or series of related dispositions of any person, asset or property located outside the United States). For the purposes of this Section 4.02(f), the value of any disposition or series of related dispositions shall mean the greater of (i) the book value or (ii) the sales price, in each case of the person, asset or property which is the subject of such disposition and, in each case, together with the indebtedness and amounts paid for negative energy price risk management positions transferred by Duke or its subsidiaries in connection with such disposition.

(g) Indebtedness. Except as disclosed in Section 4.02(g) of the Duke Disclosure Letter, Duke shall not, nor shall it permit any of its subsidiaries to, (A) incur or guarantee any indebtedness or enter into any "keep well" or other agreement to maintain any financial condition of another person or enter into any arrangement having the economic effect of any of the foregoing (including any capital leases, "synthetic" leases or conditional sale or other title retention agreements) other than (i) short-term indebtedness incurred in the ordinary course of business, (ii) letters of credit obtained in the ordinary course of business, (iii) borrowings under Duke's or its subsidiaries' existing credit facilities (or replacement facilities permitted by this Section 4.02(g)) but only to the extent the commercial paper market is unavailable to Duke upon reasonable terms and conditions, and as to which borrowings Duke agrees to notify Progress promptly following the consummation thereof, (iv) indebtedness incurred in connection with the refunding or refinancing of existing indebtedness (x) at maturity or upon final mandatory redemption (without the need for the occurrence of any special event) or (y) at a lower cost of funds, (v) indebtedness incurred to finance acquisitions permitted pursuant to Section 4.02(e) or indebtedness assumed pursuant thereto, (vi) other indebtedness in an aggregate principal amount not to exceed $500,000,000 outstanding at any time, (vii) guarantees or other credit support issued pursuant to energy price risk management or marketing positions established prior to the date of this Agreement, (viii) in addition to the guarantees or other credit support contemplated by subsection (A)(vii) of this Section 4.02(g), additional guarantees or other credit support issued in connection with energy price risk management or marketing activities in the ordinary course of business and (ix) indebtedness owed to any direct or indirect wholly-owned subsidiary of Duke, or, in the case of a subsidiary of Duke, to Duke or (B) make any loans or advances to any other person, other than (i) in the ordinary course of business consistent with past practice, (ii) to any direct or indirect wholly-owned subsidiary of Duke, or, in the case of a subsidiary of Duke, to Duke or (iii) as required pursuant to any obligation in effect as of the date of this Agreement.

(h) Marketing of Energy; Energy Price Risk Management. Except as disclosed in Section 4.02(h) of the Duke Disclosure Letter, Duke shall not, nor shall it permit any of its subsidiaries to, (i) permit any material change in policies governing or otherwise relating to energy price risk management or marketing of energy other than as a result of acquisitions or capital expenditures permitted pursuant to Section 4.02(e) or (ii) enter into any physical commodity transactions, exchange-traded futures and options transactions, over-the-counter transactions and derivatives thereof or similar transactions other than as permitted by the Duke Risk Management Guidelines.

(i) Employee Benefits. Except as required by law, or the terms of any collective bargaining agreement or any Duke Employee Benefit Plan, or as disclosed in Section 4.02(i) of the Duke Disclosure Letter or as otherwise expressly permitted by this Agreement, Duke shall not, nor shall it permit any of its subsidiaries to, enter into, adopt, amend or terminate any Duke Employee Benefit Plan, or other agreement, arrangement, plan or policy between Duke or one of its subsidiaries and one or more of its directors, officers or employees (other than any amendment that is immaterial or administrative in nature), or, except for normal increases in the ordinary course of business consistent with past practice, increase in any manner the compensation or fringe benefits of any director, executive officer or other employee, or, except for normal payments in the ordinary course of business consistent with past practice, and the award of annual bonuses on the terms and conditions set forth in Section 4.02(i) of the Duke Disclosure Letter, pay any benefit not required by any plan or arrangement in effect as of the date of this Agreement; provided, however, that the foregoing shall not restrict Duke or its subsidiaries from (i) entering into or making available to newly hired officers and employees or to officers and employees in the context of promotions based on job performance or workplace requirements in the ordinary course of business consistent with past practice, plans, agreements, benefits and compensation arrangements (including incentive grants) that have, consistent with past practice, been made available to newly hired or promoted officers and employees, (ii) entering into severance agreements with, or adopting severance plans in the ordinary course of business consistent with past practice for, employees who are not executive officers in connection with terminations of employment of such employees, or (iii) entering into or amending collective bargaining agreements with existing collective bargaining representatives or newly certified bargaining units regarding mandatory subjects of bargaining under applicable law, in each case in a manner consistent with past practice to the extent permitted by law.

(j) [Intentionally Reserved.]

(k) Accounting. Duke shall not, nor shall it permit any of its subsidiaries to, make any changes in its accounting methods materially affecting the reported consolidated assets, liabilities or results of operations of Duke, except as required by law or GAAP.

(l) Insurance. Duke shall, and shall cause its subsidiaries to, maintain with financially responsible insurance companies (or through self-insurance, consistent with past-practice) insurance in such amounts and against such risks and losses as are customary for companies engaged in their respective businesses to the extent available on commercially reasonable terms.

(m) Taxes. Except as could not reasonably be expected to have a material adverse effect on Duke, Duke shall not, nor shall it permit any of its subsidiaries to, (i) settle any claim, action or proceeding relating to Taxes or (ii) make any Tax election (this clause (m) being the sole provision of this Section 4.02 governing Tax matters).

(n) Release of Claims. Except as disclosed in Section 4.02(n) of the Duke Disclosure Letter and except with respect to any settlements or agreements with or before any Governmental Authorities in the ordinary course of business, Duke shall not, and shall not permit any of its subsidiaries to, waive, release, assign, settle or compromise any claim, action or proceeding against Duke or any of its subsidiaries, other than waivers, releases, assignments, settlements or compromises that (x) with respect to the payment of monetary damages, involve only the payment of monetary damages (A) equal to or less than the amounts specifically reserved with respect thereto on the balance sheet as of December 31, 2009 included in the Duke SEC Documents or (B) that do not exceed $30,000,000 individually or $100,000,000 in the aggregate during any consecutive twelve-month period, and (y) with respect to any non-monetary terms and conditions therein, impose or require actions that would not reasonably be expected individually or in the aggregate to have a material adverse effect on Duke.

(o) Contracts. Except as permitted by Section 4.02(i), Duke shall not, nor shall it permit any of its subsidiaries to, (i) enter into any Contract that would materially restrict, after the Effective Time, Duke and its subsidiaries (including the Surviving Corporation and its subsidiaries) with respect to engaging or competing in any line of business or in any geographic area or (ii) waive, release, or assign any material rights or claims under, or materially modify or terminate any Contract that is material to Duke and its subsidiaries, taken as a whole, (A) in any manner that is materially adverse to Duke or (B) which would prevent or materially delay the consummation of the Merger and the other transactions contemplated by this Agreement, it being understood and agreed that the restriction on material modifications and terminations in clause (ii)(A) shall not apply with respect to any Contract permitted to be entered into under clause (e), (f), (g), (h) or (n) of this Section 4.02.

Section 4.03 No Solicitation by Progress. (a) Except as expressly permitted by this Section 4.03, Progress shall not, nor shall it permit any of its subsidiaries to, nor shall it authorize or permit any of its directors, officers or employees to, and shall use its reasonable best efforts to cause any investment banker, financial advisor, attorney, accountant or other representative retained by it or any of its subsidiaries not to, directly or indirectly, (i) solicit, initiate or knowingly encourage (including by way of furnishing information), or take any other action designed to facilitate, any inquiries or the making of any proposal that constitutes a Progress Takeover Proposal or (ii) participate in any negotiations or substantive discussions regarding any Progress Takeover Proposal; provided, however, that if, at any time prior to receipt of the Progress Shareholder Approval (the "Progress Applicable Period"), the Board of Directors of Progress determines in good faith, after consultation with its legal and financial advisors, that a Progress Takeover Proposal that did not result from a breach (other than in immaterial respects) of this Section 4.03(a) is, or is reasonably likely to result in, a Progress Superior Proposal (as defined in Section 4.03(b)), and subject to providing prior written notice of its decision to take such action to

Duke and compliance with Section 4.03(c), Progress may (x) furnish information with respect to and provide access to the properties, books and records of Progress and its subsidiaries to the person making such proposal (and its representatives) pursuant to a customary confidentiality agreement containing terms no less favorable to Progress with respect to confidentiality than those set forth in the Confidentiality Agreement (the "Confidentiality Agreement") dated July 29, 2010, between Duke and Progress (provided, that such confidentiality agreement shall not in any way restrict Progress from complying with its disclosure obligations under this Agreement, including with respect to such proposal) and (y) participate in discussions or negotiations regarding such proposal. Progress, its subsidiaries and their representatives immediately shall cease and cause to be terminated any existing activities, discussions or negotiations with any parties with respect to any Progress Takeover Proposal. For purposes of this Agreement, "Progress Takeover Proposal" means any bona fide inquiry, proposal or offer from any person relating to (i) any direct or indirect acquisition or purchase of a business that constitutes 20% or more of the net revenues, net income or the assets (including equity securities) of Progress and its subsidiaries, taken as a whole (a "Progress Material Business"), (ii) any direct or indirect acquisition or purchase of 20% or more of any class of voting securities of Progress or any subsidiary of Progress owning, operating or controlling a Progress Material Business, (iii) any tender offer or exchange offer that if consummated would result in any person beneficially owning 20% or more of any class of voting securities of Progress, or (iv) any merger, consolidation, business combination, recapitalization, liquidation, dissolution or similar transaction involving Progress or any subsidiary of Progress owning, operating or controlling a Progress Material Business, in each case other than the transactions contemplated by this Agreement. Notwithstanding the foregoing and provided that Progress has otherwise complied with this Section 4.03(a), nothing in this Section 4.03(a) shall prohibit Progress or its directors, officers, employees, representatives or agents from contacting in writing any person who has made a Progress Takeover Proposal after the date of this Agreement solely to request the clarification of the terms and conditions thereof to the extent necessary to permit it to determine whether the Progress Takeover Proposal is, or is reasonably likely to result in, a Progress Superior Proposal.

(b) Except as contemplated by this Section 4.03, neither the Board of Directors of Progress nor any committee thereof shall (A) withdraw or modify, or propose publicly to withdraw or modify, in a manner adverse to Duke, the approval or recommendation to Progress's shareholders by such Board of Directors or such committee of this Agreement or the Merger, (B) approve or recommend, or propose publicly to approve or recommend, any Progress Takeover Proposal, or (C) cause Progress to enter into any letter of intent, agreement in principle, acquisition agreement or other similar agreement (each, a "Progress Acquisition Agreement") related to any Progress Takeover Proposal. Notwithstanding the foregoing:

(i) in response to a Progress Takeover Proposal that did not result from a breach (other than in immaterial respects) of Section 4.03(a), during the Progress Applicable Period, the Board of Directors of Progress may, if it determines in good faith, after consulting with outside counsel, that the failure to take such action would be reasonably likely to result in a breach of the Board of Directors' fiduciary obligations under applicable law, (A) withdraw or modify, or propose publicly to withdraw or modify, the approval or recommendation by such Board of Directors or any committee thereof of this Agreement or the Merger, (B) approve or recommend, or propose to approve or recommend, any Progress Superior Proposal, or (C) terminate this Agreement pursuant to Section 7.01(d), but only after (1) in the case of each of clauses (B) or (C), such Board of Directors has determined in good faith that such Progress Takeover Proposal constitutes a Progress Superior Proposal, and (2) in the case of clause (C), (I) Progress has notified Duke in writing of the determination that such Progress Takeover Proposal constitutes a Progress Superior Proposal and (II) at least five business days following receipt by Duke of such notice, the Board of Directors of Progress has determined that such Progress Superior Proposal remains a Progress Superior Proposal; provided, however, that in the event that any such Progress Takeover Proposal is thereafter modified by the person making such Progress Takeover Proposal and the Board of Directors determines pursuant to clause (C) to terminate this Agreement pursuant to Section 7.01(d), Progress shall again comply with clauses (I) and (II) of this paragraph (b)(i) except that the five business-day period shall be reduced to two business days; and

(ii) in circumstances other than in response to a Progress Takeover Proposal as provided in Section 4.03(b)(i), during the Progress Applicable Period, the Board of Directors of Progress may, if it determines in good faith, after consulting with outside counsel, that the failure to take such action would be reasonably likely to result in a breach of the Board of Directors' fiduciary obligations under applicable law, withdraw or modify, or propose publicly to withdraw or modify, the approval or recommendation by such Board of Directors or any committee thereof of this Agreement or the Merger, but only after (1) Progress has notified Duke in writing that the Board of Directors of Progress is prepared to make the determination set forth in this clause (ii) setting forth the reasons therefor in reasonable detail, (2) for a period of five business days following Duke's receipt of the notice set forth in clause (1) of this sentence (or, if the period from the time of receipt by Duke of such notice to the Progress Shareholders Meeting shall be less than five business days, for such lesser period), Progress negotiates with Duke in good faith to make such adjustments to the terms and conditions of this Agreement, the Merger and the other transactions contemplated hereby as would enable the Progress Board of Directors to proceed with its recommendation of this Agreement and the Merger and (3) at the end of such five-business day period (or such lesser period, as the case may be, in accordance with this clause (ii)) the Board of Directors of Progress maintains its determination described in this clause (ii) (after taking into account Duke's proposed adjustments, if any, to the terms and conditions of this Agreement, the Merger and the other transactions contemplated hereby).

For purposes of this Agreement, "Progress Superior Proposal" means any written Progress Takeover Proposal that the Board of Directors of Progress determines in good faith (after consultation with a financial advisor of nationally recognized reputation) to be more favorable (taking into account (i) all financial and strategic considerations, including relevant legal, financial, regulatory and other aspects of such Progress Takeover Proposal and the Merger and the other transactions contemplated by this Agreement deemed relevant by the Board of Directors, (ii) the identity of the third party making such Progress Takeover Proposal, and (iii) the conditions and prospects for completion of such Progress Takeover Proposal) to Progress's shareholders than the Merger and the other transactions contemplated by this Agreement (taking into account all of the terms of any proposal by Duke to amend or modify the terms of the Merger and the other transactions contemplated by this Agreement), except that (x) the references to "20%" in clauses (i), (ii) and (iii) of the definition of "Progress Takeover Proposal" in Section 4.03(a) shall each be deemed to be a reference to "50%", (y) a "Progress Takeover Proposal" shall only be deemed to refer to a transaction involving Progress, and not any of its subsidiaries or Progress Material Businesses alone, and (z) the references to "or any subsidiary of Progress owning, operating or controlling a Progress Material Business" in clauses (ii) and (iv) shall be deemed to be deleted.

(c) In addition to the obligations of Progress set forth in paragraphs (a) and (b) of this Section 4.03, Progress shall as promptly as practicable advise Duke, orally and in writing, of any Progress Takeover Proposal or of any request for information relating to any Progress Takeover Proposal (and in any case within 48 hours of such request or the receipt of such Progress Takeover Proposal), the principal terms and conditions of such request or Progress Takeover Proposal and the identity of the person making such request or Progress Takeover Proposal. Progress shall keep Duke informed in all material respects of the status and details (including amendments or proposed amendments) of any such request or Progress Takeover Proposal. Contemporaneously with any termination by Progress of this Agreement pursuant to Section 7.01(b)(i), Progress shall provide Duke with a written verification that it has complied with its obligations pursuant to this Section 4.03(c) (other than noncompliance which is immaterial).

(d) Nothing contained in this Agreement shall prohibit Progress or its Board of Directors or any committee thereof from (i) taking and disclosing to its shareholders a position contemplated by Rule 14e-2(a) promulgated under the Exchange Act or from making any disclosure to Progress's shareholders if, in the good faith judgment of the Board of Directors of Progress, after consultation with outside counsel, failure so to disclose would be inconsistent with its or Progress's obligations under applicable law or (ii) taking actions permitted by Section 4.01(f).

Section 4.04 No Solicitation by Duke. (a) Except as expressly permitted by this Section 4.04, Duke shall not, nor shall it permit any of its subsidiaries to, nor shall it authorize or permit any of its directors, officers or employees to, and shall use its reasonable best efforts to cause any investment banker, financial advisor, attorney, accountant or other representative retained by it or any of its subsidiaries not to, directly or indirectly, (i) solicit, initiate or knowingly encourage (including by way of furnishing information), or take any other action designed to facilitate, any inquiries or the making of any proposal that constitutes a Duke Takeover Proposal or (ii) participate in any negotiations or substantive discussions regarding any Duke Takeover Proposal; provided, however, that if, at any time prior to receipt of the Duke Shareholder Approval (the "Duke Applicable Period"), the Board of Directors of Duke determines in good faith, after consultation with its legal and financial advisors, that a Duke Takeover Proposal that did not result from a breach (other than in immaterial respects) of this Section 4.04(a) is, or is reasonably likely to result in, a Duke Superior Proposal (as defined in Section 4.04(b)), and subject to providing prior written notice of its decision to take such action to Progress and compliance with Section 4.04(c), Duke may (x) furnish information with respect to and provide access to the properties, books and records of Duke and its subsidiaries to the person making such proposal (and its representatives) pursuant to a customary confidentiality agreement containing terms no less favorable to Duke with respect to confidentiality than those set forth in the Confidentiality Agreement (provided, that such confidentiality agreement shall not in any way restrict Duke from complying with its disclosure obligations under this Agreement, including with respect to such proposal) and (y) participate in discussions or negotiations regarding such proposal. Duke, its subsidiaries and their representatives immediately shall cease and cause to be terminated any existing activities, discussions or negotiations with any parties with respect to any Duke Takeover Proposal. For purposes of this Agreement, "Duke Takeover Proposal" means any bona fide inquiry, proposal or offer from any person relating to (i) any direct or indirect acquisition or purchase of a business that constitutes 20% or more of the net revenues, net income or the assets (including equity securities) of Duke and its subsidiaries, taken as a whole (a "Duke Material

Business"), (ii) any direct or indirect acquisition or purchase of 20% or more of any class of voting securities of Duke or any subsidiary of Duke owning, operating or controlling a Duke Material Business, (iii) any tender offer or exchange offer that if consummated would result in any person beneficially owning 20% or more of any class of voting securities of Duke, or (iv) any merger, consolidation, business combination, recapitalization, liquidation, dissolution or similar transaction involving Duke or any subsidiary of Duke owning, operating or controlling a Duke Material Business, in each case other than the transactions contemplated by this Agreement. Notwithstanding the foregoing and provided that Duke has otherwise complied with this Section 4.04(a), nothing in this Section 4.04(a) shall prohibit Duke or its directors, officers, employees, representatives or agents from contacting in writing any person who has made a Duke Takeover Proposal after the date of this Agreement solely to request the clarification of the terms and conditions thereof to the extent necessary to permit it to determine whether the Duke Takeover Proposal is, or is reasonably likely to result in, a Duke Superior Proposal.

(b) Except as contemplated by this Section 4.04, neither the Board of Directors of Duke nor any committee thereof shall (A) withdraw or modify, or propose publicly to withdraw or modify, in a manner adverse to Progress, the approval or recommendation to Duke's shareholders by such Board of Directors or such committee of the Duke Share Issuance or Duke Charter Amendment, (B) approve or recommend, or propose publicly to approve or recommend, any Duke Takeover Proposal, or (C) cause Duke to enter into any letter of intent, agreement in principle, acquisition agreement or other similar agreement (each, a "Duke Acquisition Agreement") related to any Duke Takeover Proposal. Notwithstanding the foregoing:

(i) in response to a Duke Takeover Proposal that did not result from a breach (other than in immaterial respects) of Section 4.04(a), during the Duke Applicable Period, the Board of Directors of Duke may, if it determines in good faith, after consulting with outside counsel, that the failure to take such action would be reasonably likely to result in a breach of the Board of Directors' fiduciary obligations under applicable law, (A) withdraw or modify, or propose publicly to withdraw or modify, the approval or recommendation by such Board of Directors or any committee thereof of the Duke Share Issuance or Duke Charter Amendment, (B) approve or recommend, or propose to approve or recommend, any Duke Superior Proposal, or (C) terminate this Agreement pursuant to Section 7.01(f), but only after (1) in the case of each of clauses (B) or (C), such Board of Directors has determined in good faith that such Duke Takeover Proposal constitutes a Duke Superior Proposal, and (2) in the case of clause (C), (I) Duke has notified Progress in writing of the determination that such Duke Takeover Proposal constitutes a Duke Superior Proposal and (II) at least five business days following receipt by Progress of such notice, the Board of Directors of Duke has determined that such Duke Superior Proposal remains a Duke Superior Proposal; provided, however, that in the event that any such Duke Takeover Proposal is thereafter modified by the person making such Duke Takeover Proposal and the Board of Directors determines pursuant to clause (C) to terminate this Agreement pursuant to Section 7.01(f), Duke shall again comply with clauses (I) and (II) of this paragraph (b)(i) except that the five business-day period shall be reduced to two business days; and

(ii) in circumstances other than in response to a Duke Takeover Proposal as provided in Section 4.04(b)(i), during the Duke Applicable Period, the Board of Directors of Duke may, if it determines in good faith, after consulting with outside counsel, that the failure to take such action would be reasonably likely to result in a breach of the Board of Directors' fiduciary obligations under applicable law, withdraw or modify, or propose publicly to withdraw or modify, the approval or recommendation by such Board of Directors or any committee thereof of the Duke Share Issuance or Duke Charter Amendment, but only after (1) Duke has notified Progress in writing that the Board of Directors of Duke is prepared to make the determination set forth in this clause (ii) setting forth the reasons therefor in reasonable detail, (2) for a period of five business days following Progress's receipt of the notice set forth in clause (1) of this sentence (or, if the period from the time of receipt by Progress of such notice to the Duke Shareholders Meeting shall be less than five business days, for such lesser period), Duke negotiates with Progress in good faith to make such adjustments to the terms and conditions of this Agreement, the Merger and the other transactions contemplated hereby as would enable the Duke Board of Directors to proceed with its recommendation of the Duke Share Issuance and the Duke Charter Amendment and (3) at the end of such five-business day period (or such lesser period, as the case may be, in accordance with this clause (ii)) the Board of Directors of Duke maintains its determination described in this clause (ii) (after taking into account Progress's proposed adjustments, if any, to the terms and conditions of this Agreement, the Merger and the other transactions contemplated hereby).

For purposes of this Agreement, a "Duke Superior Proposal" means any written Duke Takeover Proposal that the Board of Directors of Duke determines in good faith (after consultation with a financial advisor of nationally recognized reputation) to be more favorable (taking into account (i) all financial and strategic considerations, including relevant legal, financial, regulatory and other aspects of such Duke Takeover Proposal and the Merger and the other transactions contemplated by this Agreement deemed relevant by the Board of Directors, (ii) the identity of the third party making such Duke Takeover Proposal, and (iii) the conditions and prospects for completion of such Duke Takeover Proposal) to Duke's shareholders than the Merger and the other transactions contemplated by this Agreement (taking into account all of the terms of any proposal by Progress to amend or modify the terms of the Merger and the other transactions contemplated by this Agreement), except that (x) the references to "20%" in clauses (i), (ii) and (iii) of the definition of "Duke Takeover Proposal" in Section 4.04(a) shall each be deemed to be a reference to "50%", (y) a "Duke Takeover Proposal" shall only be deemed to refer to a transaction involving Duke, and not any of its subsidiaries or Duke Material Businesses alone, and (z) the references to "or any subsidiary of Duke owning, operating or controlling a Duke Material Business" in clauses (ii) and (iv) shall be deemed to be deleted.

(c) In addition to the obligations of Duke set forth in paragraphs (a) and (b) of this Section 4.04, Duke shall as promptly as practicable advise Progress, orally and in writing, of any Duke Takeover Proposal or of any request for information relating to any Duke Takeover Proposal (and in any case within 48 hours of such request or the receipt of such Duke Takeover Proposal), the principal terms and conditions of such request or Duke Takeover Proposal and the identity of the person making such request or Duke Takeover Proposal. Duke shall keep Progress informed in all material respects of the status and details (including amendments or proposed amendments) of any such request or Duke Takeover Proposal. Contemporaneously with any termination by Duke of this Agreement pursuant to Section 7.01(b)(i), Duke shall provide Progress with a written verification that it has complied with its obligations pursuant to this Section 4.04(c) (other than noncompliance which is immaterial).

(d) Nothing contained in this Agreement shall prohibit Duke or its Board of Directors or any committee thereof from (i) taking and disclosing to its shareholders a position contemplated by Rule 14e-2(a) promulgated under the Exchange Act or from making any disclosure to Duke's shareholders if, in the good faith judgment of the Board of Directors of Duke, after consultation with outside counsel, failure so to disclose would be inconsistent with its or Duke's obligations under applicable law or (ii) taking actions permitted by Section 4.02(f).

Section 4.05 Other Actions. Each of Progress and Duke shall use its reasonable best efforts not to, and shall use its reasonable best efforts not to permit any of its respective subsidiaries to, take any action that would, or that could reasonably be expected to, result in (i) any of the representations and warranties of such party set forth in this Agreement that is qualified as to materiality or material adverse effect becoming untrue, (ii) any of such representations and warranties that is not so qualified becoming untrue in any material respect, or (iii) any condition to the Merger set forth in Article VI not being satisfied.

Section 4.06 Coordination of Dividends. From the date of this Agreement until the Effective Time, Duke and Progress shall coordinate with each other regarding the declaration and payment of dividends in respect of the shares of Progress Common Stock and Duke Common Stock and the record dates and payment dates relating thereto, it being the intention of Progress and Duke that no holder of Progress Common Stock or Duke Common Stock shall receive two dividends, or fail to receive one dividend, for any single calendar quarter with respect to its shares of Progress Common Stock or Duke Common Stock (including Duke Common Stock issued in connection with the Merger), as the case may be. In furtherance of and without limiting the generality of the foregoing, if at the time that Progress would otherwise declare a regular quarterly cash dividend pursuant to Section 4.01(c)(i)(A) the parties expect the Closing Date to occur during the period of time from and after the record date for such Progress dividend and prior to the record date for the next subsequent regular quarterly cash dividend of Duke, the parties shall coordinate to reduce the amount of such Progress dividend to an amount reasonably calculated to effectuate the intent of the parties described in the first sentence of this Section 4.06. In the event (a) the Closing Date would, in the absence of this Section 4.06, occur after the record date for the last regular quarterly cash dividend of Progress prior to the Closing Date and prior to the record date for the next subsequent regular quarterly cash dividend of Duke and (b) such last recent Progress regular quarterly cash dividend occurring prior to the Closing shall not have been reduced as contemplated by the preceding sentence, Duke shall be permitted to (i) declare and pay a special dividend to Duke stockholders immediately prior to the Closing in an amount reasonably calculated to effectuate the intent of the parties described in the first sentence of this Section 4.06 or (ii) subject to the prior written consent of Progress (which consent shall not be unreasonably withheld), postpone the Closing to a date no later than one business day after the record date for the next succeeding regular quarterly cash dividend of Duke (in which event Progress shall be permitted to declare and pay a special dividend immediately prior to the Closing in an amount reasonably calculated to effectuate the intent of the parties described in the first sentence of this Section 4.06, and neither party shall be entitled to terminate this Agreement pursuant to Section 7.01(b)(i) during the period of such postponement).

ARTICLE V

ADDITIONAL AGREEMENTS

Section 5.01 Preparation of the Form S-4 and the Joint Proxy Statement; Shareholders Meetings. (a) As soon as practicable following the date of this Agreement, Progress and Duke shall prepare and file with the SEC the Joint Proxy Statement and Duke shall prepare and file with the SEC the Form S-4, in which the Joint Proxy Statement will be included. The Joint Proxy Statement and Form S-4 shall comply as to form in all material respects with the applicable provisions of the Securities Act and the Exchange Act and the rules and regulations thereunder. Duke shall use its reasonable best efforts, and Progress will reasonably cooperate with Duke in such efforts, to have the Form S-4 declared effective under the Securities Act as promptly as practicable after such filing and to keep the Form S-4 effective as long as necessary to consummate the Merger and other transactions contemplated hereby. Progress will use its reasonable best efforts to cause the Joint Proxy Statement to be mailed to Progress's shareholders, and Duke will use its reasonable best efforts to cause the Joint Proxy Statement to be mailed to Duke's shareholders, in each case as promptly as practicable after the Form S-4 is declared effective under the Securities Act. Duke shall also take any action required to be taken by it under any applicable state or provincial securities laws in connection with the issuance of Duke Common Stock in the Merger and each party shall furnish all information concerning itself and its shareholders as may be reasonably requested in connection with any such action. Each party will advise the others, promptly after it receives notice thereof, of the time when the Form S-4 has become effective or any supplement or amendment has been filed, the issuance of any stop order, the suspension of the qualification of the Duke Common Stock issuable in connection with the Merger for offering or sale in any jurisdiction, or any request by the SEC for amendment of the Joint Proxy Statement or the Form S-4 or comments thereon and responses thereto or requests by the SEC for additional information. If prior to the Effective Time any event occurs with respect to Progress, Duke or any subsidiary of Progress or Duke, respectively, or any change occurs with respect to information supplied by or on behalf of Progress or Duke, respectively, for inclusion in the Joint Proxy Statement or the Form S-4 that, in each case, is required to be described in an amendment of, or a supplement to, the Joint Proxy Statement or the Form S-4, Progress or Duke, as applicable, shall promptly notify the other of such event, and Progress or Duke, as applicable, shall cooperate with the other in the prompt filing with the SEC of any necessary amendment or supplement to the Joint Proxy Statement and the Form S-4 and, as required by law, in disseminating the information contained in such amendment or supplement to Progress's shareholders and to Duke's shareholders; provided that no amendment or supplement to the Joint Proxy Statement or the Form S-4 shall be filed by either party, and no material correspondence with the SEC shall be made by either party, without providing the other party a reasonable opportunity to review and comment thereon.

(b) Progress shall, as soon as reasonably practicable following the date of this Agreement, duly call, give notice of, convene and hold a meeting of its shareholders (the "Progress Shareholders Meeting") for the purpose of obtaining the Progress Shareholder Approval and any other matters required under applicable law to be considered at the Progress Shareholders Meeting. Without limiting the generality of the foregoing, Progress agrees that unless this Agreement is terminated pursuant to Section 7.01, its obligations pursuant to the first sentence of this Section 5.01(b) shall not be affected by (i) the commencement, public proposal, public disclosure or communication to Progress of any Progress Takeover Proposal, (ii) the withdrawal or modification by the Board of Directors of Progress of its approval or recommendation to Progress's shareholders of this Agreement, the Merger or the other transactions contemplated hereby, or (iii) the approval or recommendation of any Progress Superior Proposal. Notwithstanding any of the events set forth in clauses (i), (ii) and (iii) of the immediately preceding sentence, in the event Progress fulfills its obligations pursuant to this Section 5.01(b) and the Progress Shareholder Approval is not obtained at the Progress Shareholders Meeting, Duke shall not thereafter have the right to terminate this Agreement pursuant to Sections 7.01(h)(i) as a result of the Board of Directors of Progress (or any committee thereof) having, pursuant to Section 4.03(b)(ii), withdrawn or modified, or proposed publicly to withdraw or modify, the approval or recommendation by such Board of Directors of this Agreement or the Merger; provided Duke shall retain all other rights to terminate this Agreement set forth in Section 7.01.

(c) Duke shall, as soon as reasonably practicable following the date of this Agreement, duly call, give notice of, convene and hold a meeting of its shareholders (the "Duke Shareholders Meeting") for the purpose of obtaining the Duke Shareholder Approval and any other matters required under applicable law to be considered at the Duke Shareholders Meeting. Without limiting the generality of the foregoing, Duke agrees that unless this Agreement is terminated pursuant to Section 7.01, its obligations pursuant to the first sentence of this Section 5.01(c) shall not be affected by (i) the commencement, public proposal, public disclosure or communication to Duke of any Duke Takeover Proposal, (ii) the withdrawal or modification by the Board of Directors of Duke of its approval or recommendation to Duke's shareholders of the Duke Share Issuance and the Duke Charter Amendment, or (iii) the approval or recommendation of any Duke Superior Proposal. Notwithstanding any of the events set forth in clauses (i), (ii) and (iii) of the immediately preceding sentence, in the event Duke fulfills its obligations pursuant to this Section 5.01(c) and the Duke Shareholder Approval is not obtained at the Duke Shareholders Meeting, Progress shall not thereafter have the right to terminate this Agreement pursuant to Section 7.01(g)(i) as a result of the Board of Directors of Duke (or any committee thereof) having, pursuant to Section 4.04(b)(ii), withdrawn or modified, or proposed publicly to withdraw or modify, the approval or recommendation by such Board of Directors of this Agreement or the Duke Merger; provided Progress shall retain all other rights to terminate this Agreement set forth in Section 7.01.

Subject to receipt of the Duke Shareholder Approval, on or before the Closing Date and prior to the Effective Time, Duke shall file with the Secretary of State of the State of Delaware a Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Duke providing for, after prior consultation with Progress, a 1-for-2 or 1-for-3 reverse stock split with respect to the Duke Common Stock (the "Duke Charter Amendment"), such Certificate of Amendment to become effective on the Closing Date prior to the filing of the Articles of Merger with the Secretary of State of the State of North Carolina.

(d) Progress and Duke will use their reasonable best efforts to hold the Duke Shareholders Meeting and the Progress Shareholders Meeting on the same date and as soon as practicable after the date of this Agreement.

Section 5.02 Letters of Duke's Accountants. Duke shall use its reasonable best efforts to cause to be delivered to Progress two letters from Duke's independent accountants, one dated a date within two business days before the date on which the Form S-4 shall become effective and one dated a date within two business days before the Closing Date, each addressed to Progress, in form and substance reasonably satisfactory to Progress and customary in scope and substance for comfort letters delivered by independent public accountants in connection with registration statements similar to the Form S-4.

Section 5.03 Letters of Progress's Accountants. Progress shall use its reasonable best efforts to cause to be delivered to Duke two letters from Progress's independent accountants, one dated a date within two business days before the date on which the Form S-4 shall become effective and one dated a date within two business days before the Closing Date, each addressed to Duke, in form and substance reasonably satisfactory to Duke and customary in scope and substance for comfort letters delivered by independent public accountants in connection with registration statements similar to the Form S-4.

Section 5.04 Access to Information; Effect of Review.

(a) Access. Subject to the Confidentiality Agreement, to the extent permitted by applicable law, each of Progress and Duke shall, and shall cause each of its respective subsidiaries to, and, so long as consistent with its confidentiality obligations under its applicable agreements, shall use its respective reasonable best efforts to cause the Progress Joint Ventures and Duke Joint Ventures, respectively, to, afford to the other party and to the officers, employees, accountants, counsel, financial advisors and other representatives of such other party reasonable access during normal business hours during the period prior to the Effective Time to all their respective properties, books, contracts, commitments, personnel and records and, during such period, to the extent permitted by applicable law, each of Progress and Duke shall, and shall cause each of its respective subsidiaries to, and, so long as consistent with its confidentiality and other contractual obligations under its applicable agreements, shall use its respective reasonable best efforts to cause the Progress Joint Ventures and Duke Joint Ventures, respectively, to, (i) confer on a regular and frequent basis with one or more representatives of the other party to discuss material operational and regulatory matters and the general status of its ongoing operations, (ii) advise the other party of any change or event that has had or could reasonably be expected to have a material adverse effect on such party, and (iii) furnish promptly all other information concerning its business, properties and personnel, in each case as such other party may reasonably request; provided, however, that no actions shall be taken pursuant to this Section 5.04(a) that would create a risk of loss or waiver of the attorney/client privilege, provided, further, that the parties shall use their respective commercially reasonable efforts to allow for access and disclosure of information in a manner reasonably acceptable to the parties that does not result in the loss or waiver of the attorney-client privilege (which efforts shall include entering into mutually acceptable joint defense agreements between the parties if doing so would reasonably permit the disclosure of information without violating applicable law or jeopardizing such attorney-client privilege). Notwithstanding the foregoing, if a party requests access to proprietary information of the other party, the disclosure of which would have a material adverse effect on the other party if the Closing were not to occur (giving effect to the requesting party's obligations under the Confidentiality Agreement), such information shall only be disclosed to the extent reasonably agreed upon by the chief financial officers (or their designees) of Progress and Duke. All information exchanged pursuant to this Section 5.04(a) shall be subject to the Confidentiality Agreement.

(b) Effect of Review. No review pursuant to this Section 5.04 shall have any effect for the purpose of determining the accuracy of any representation or warranty given by any of the parties hereto to any of the other parties hereto.

Section 5.05 Regulatory Matters; Reasonable Best Efforts.

(a) Regulatory Approvals. Each party hereto shall cooperate and promptly prepare and file all necessary documentation, to effect all necessary applications, notices, petitions and filings, and shall use reasonable best efforts to take or cause to be taken all actions, and do or cause to be done all things in order to obtain all approvals and authorizations of all Governmental Authorities, necessary or advisable to consummate and make effective, in the most expeditious manner reasonably practicable, the Merger and the other transactions contemplated by this Agreement, including the Progress Required Statutory Approvals and the Duke Required Statutory Approvals; provided, however, that Progress shall have primary responsibility for the preparation and filing of any related applications, filings or other materials with the FPSC and the NCUC and PSCSC, provided, further, that Duke shall have primary responsibility for the preparation and filing of any related applications, filings or other materials with the PUCO, the IURC and the KPSC. Progress shall have the right to review and approve in advance all characterizations of the information relating to Progress, on the one hand, and Duke shall have the right to review and approve in advance all characterizations of the information relating to Duke, on the other hand, in either case, that appear in any application, notice, petition or filing made in connection with the Merger or the other transactions contemplated by this Agreement. Progress and Duke agree that they will consult and cooperate with each other with respect to the obtaining of all such necessary approvals and authorizations of Governmental Authorities.

(b) Reasonable Best Efforts. Subject to the terms and conditions set forth in this Agreement, each of the parties hereto shall use its reasonable best efforts (subject to, and in accordance with, applicable law) to take, or cause to be taken, promptly all actions, and to do, or cause to be done, promptly and to assist and cooperate with the other parties in doing, all things necessary, proper or advisable to consummate and make effective the Merger and the other transactions contemplated by this Agreement, including (i) the obtaining of all necessary Consents or waivers from third parties and Governmental Authorities, (ii) the defending of any lawsuits or other legal proceedings, whether judicial or administrative, challenging this Agreement or the consummation of the transactions contemplated by this Agreement, and (iii) the execution and delivery of any additional instruments necessary to consummate the transactions contemplated by this Agreement. For purposes of this Agreement, "reasonable best efforts" shall not include nor require either party or its subsidiaries to (A) sell, or agree to sell, hold or agree to hold separate, or otherwise dispose or agree to dispose of any asset, in each case if such sale, separation or disposition or agreement with respect thereto would, individually or in the aggregate, reasonably be expected to have a material adverse effect on the expected benefits of the transactions contemplated by this Agreement to such party, or (B) conduct or agree to conduct its business in any particular manner if such conduct or agreement with respect thereto would, individually or in the aggregate, reasonably be expected to have a material adverse effect on the expected benefits of the transactions contemplated by this Agreement to such party, or (C) agree to any order, action or regulatory condition of any regulatory body, whether in an approval proceeding or another regulatory proceeding, that, if effected, would cause a material reduction in the expected benefits for such party's shareholders (for example, the parties expect their customers to participate in the benefits of the transactions contemplated by this Agreement in amounts up to but not exceeding (x) the benefits of joint system dispatch and fuel savings as they materialize in future fuel clause proceedings and (y) rates that are lower than they otherwise would have been as net merger savings materialize in future rate proceedings initiated in the ordinary course of business) (any of the foregoing effects, a "Burdensome Effect").

(c) State Anti-Takeover Statutes. Without limiting the generality of Section 5.05(b), Progress and Duke shall (i) take all action necessary to ensure that no state anti-takeover statute or similar statute or regulation is or becomes applicable to the Merger, this Agreement or any of the other transactions contemplated by this Agreement and (ii) if any state anti-takeover statute or similar statute or regulation becomes applicable to the Merger, this Agreement or any other transaction contemplated by this Agreement, take all action necessary to ensure that the Merger and the other transactions contemplated by this Agreement may be consummated as promptly as reasonably practicable on the terms contemplated by this Agreement and otherwise to minimize the effect of such statute or regulation on the Merger and the other transactions contemplated by this Agreement.

Section 5.06 Stock Options; Restricted Stock and Equity Awards; Stock Plans. (a) At the Effective Time, each Progress Employee Stock Option, whether vested or unvested, shall be converted into an option to acquire, on the same terms and conditions as were applicable under such Progress Employee Stock Option, including vesting, a number of shares of Duke Common Stock equal to the number of shares of Progress Common Stock subject to such Progress Employee Stock Option immediately before the Effective Time multiplied by the Exchange Ratio (rounded down to the nearest whole share) at a price per share of Duke Common Stock equal to the price per share under such Progress Employee Stock Option divided by the Exchange Ratio (rounded up to the nearest cent) (each, as so adjusted, a "Progress Adjusted Option");

(i) at the Effective Time, each award of restricted shares of Progress Common Stock ("Progress Restricted Stock") shall be converted into an award of a number of restricted shares of Duke Common Stock equal to the number of restricted shares of Progress Common Stock multiplied by the Exchange Ratio, on the same terms and conditions as were applicable to such award of restricted shares of Progress Common Stock, including vesting ("Progress Adjusted Restricted Stock");

(ii) at the Effective Time, each Progress Restricted Stock Unit shall be converted into an award of a number of restricted stock units of Duke Common Stock equal to the number of restricted stock units of Progress Common Stock multiplied by the Exchange Ratio, on the same terms and conditions as were applicable to such award of restricted stock units of Progress Common Stock, including vesting ("Progress Adjusted Restricted Stock Units");

(iii) at the Effective Time, each Progress Performance Share shall be assumed and converted into an award of a number of performance shares of Duke Common Stock equal to the number of performance shares of Progress Common Stock multiplied by the Exchange Ratio, on the same terms and conditions as were applicable to such award of performance shares of Progress Common Stock, including vesting, and the performance measurement period for such performance shares shall remain open (such that no payments shall be made under the terms of such performance shares solely as a result of or in connection with the Merger) and the

Compensation Committee of the Board of Directors of Duke shall adjust the performance measures of such performance shares as soon as practicable after the Effective Time as it determines is appropriate and equitable to reflect the performance of Progress during the performance measurement period prior to the Effective Time, the transactions contemplated by this Agreement and the performance measures under awards made to similarly situated Duke employees for the same or comparable performance cycle (the "Progress Adjusted Performance Shares");

(iv) all outstanding Other Progress Equity Awards, whether vested or unvested, as of immediately prior to the Effective Time shall be converted into an equity or equity-based award in respect of a number of shares of Duke Common Stock equal to the number of shares of Progress Common Stock represented by such award multiplied by the Exchange Ratio, on the same terms and conditions as were applicable to such Progress equity or equity-based award, including vesting ("Other Progress Adjusted Equity Awards"); and

(v) prior to the Effective Time, the Board of Directors of Progress (or, if appropriate, any committee administering the Progress Employee Stock Option Plans) shall adopt such resolutions or take such other actions as may be required to effect the foregoing and to ensure that the conversion pursuant to Section 2.01(b) of the Progress Common Stock held by any director or officer of Progress and the conversion pursuant to this Section 5.06(a) into Progress Adjusted Options of Progress Employee Stock Options, Progress Adjusted Restricted Stock of Progress Restricted Stock, Progress Adjusted Restricted Stock Units of Progress Restricted Stock Units, Progress Adjusted Performance Shares of Progress Performance Shares and Other Progress Adjusted Equity Awards of Other Progress Equity Awards held by any director or officer of Progress will be eligible for exemption under Rule 16b-3(e) under the Exchange Act.

(b) Prior to the Effective Time, the Board of Directors of Duke shall adopt such resolutions or take such other actions as may be required to ensure to the maximum extent permitted by law that the conversion pursuant to Section 2.01(a) of the Progress Common Stock held by any director or officer of Progress and the conversion pursuant to Section 5.06(a) will be eligible for exemption under Rule 16b-3(e) under the Exchange Act. Prior to the Effective Time, Progress shall deliver to the holders of Progress Adjusted Options, Progress Adjusted Restricted Stock, Progress Adjusted Restricted Stock Units, Progress Adjusted Performance Shares and Other Progress Adjusted Equity Awards appropriate notices setting forth such holders' rights pursuant to the respective plans and this Agreement (collectively, the "Stock Plans").

(c) At the Effective Time, by virtue of the Merger, the Stock Plans shall be assumed by Duke, with the result that all obligations of Progress under the Stock Plans, including with respect to awards outstanding at the Effective Time under each Stock Plan, shall be obligations of Duke following the Effective Time. Prior to the Effective Time, Duke shall take all necessary actions for the assumption of the Stock Plans, including the reservation, issuance and listing of Duke Common Stock in a number at least equal to the number of shares of Duke Common Stock that will be subject to Progress Adjusted Options, Progress Adjusted Restricted Stock Units, Progress Adjusted Performance Shares and Other Progress Adjusted Equity Awards. As promptly as practicable following the Effective Time, Duke or its subsidiaries shall prepare and file with the SEC a registration statement on Form S-8 (or another appropriate form) registering a number of shares of Duke Common Stock determined in accordance with the preceding sentence. Such registration statement shall be kept effective (and the current status of the prospectus or prospectuses required thereby shall be maintained) at least for so long as Progress Adjusted Options, Progress Adjusted Restricted Stock Units, Progress Adjusted Performance Shares and Other Progress Adjusted Equity Awards remain outstanding.

Section 5.07 Employee Matters. (a) From and after the Effective Time, the Duke Employee Benefit Plans and the Progress Employee Benefit Plans in effect as of the date of this Agreement and at the Effective Time shall remain in effect with respect to employees and former employees of Duke or Progress and their subsidiaries (the "Newco Employees"), respectively, covered by such Plans at the Effective Time, until such time as Duke and Progress together shall otherwise determine, subject to applicable laws and the terms of such plans. Prior to the Effective Time, Duke and Progress shall cooperate in reviewing, evaluating and analyzing Duke Employee Benefit Plans and Progress Employee Benefit Plans with a view towards maintaining appropriate Plans for Newco Employees.

(b) With respect to any Plans in which any Newco Employees who are employees of Duke or Progress (or their subsidiaries) prior to the Effective Time first become eligible to participate on or after the Effective Time, and in which such Newco Employees did not participate prior to the Effective Time (the "New Plans"), Duke shall, or shall cause its subsidiaries to, use reasonable best efforts, subject to applicable law, to: (i) waive all pre-existing conditions, exclusions and waiting periods with respect to participation and coverage requirements applicable to the Newco Employees and their eligible dependents under any New Plans in which such employees may be eligible to participate after the Effective Time, except to the extent such pre-existing conditions, exclusions or waiting periods would apply under the analogous Duke Employee Benefit Plan or Progress Employee Benefit Plan, as the case may be; (ii) provide each Newco Employee and their eligible dependents with credit for any co-payments and deductibles paid prior to the Effective Time under a Duke Employee Benefit Plan or Progress Employee Benefit Plan (to the same extent that such credit was given under the analogous Duke Employee Benefit Plan or Progress Employee Benefit Plan, as applicable, prior to the Effective Time) in satisfying any applicable deductible or out-of-pocket requirements under any New Plans in which such employees may be eligible to participate after the Effective Time; and (iii) recognize all service of the Newco Employees with Progress and Duke, and their respective affiliates, for all purposes (including, for purposes of eligibility to participate, vesting credit, entitlement to benefits, and, except with respect to defined benefit pension plans, benefit accrual) in any New Plan in which such employees may be eligible to participate after the Effective Time, including any severance plan, to the extent such service is taken into account under the applicable New Plan; provided that the foregoing shall not apply to the extent it would result in duplication of benefits.

(c) Prior to the Effective Time, Duke and Progress shall cooperate to establish common retention, relocation and severance policies or plans that apply to Newco Employees on and after the Effective Time; provided, however, that for the period beginning on the Closing Date and ending on the second anniversary of the Closing Date (the "Continuation Period"), each Newco Employee who was an employee of Progress immediately prior to the Effective Time whose employment is terminated during the Continuation Period shall be eligible to receive severance benefits in amounts and on terms and conditions no less favorable than those provided to employees of Progress pursuant to plans or policies in effect immediately prior to the Effective Time, including, without limitation, the Progress CIC Plan (as defined in Section 5.07(d)).

(d) Duke acknowledges and agrees that (i) it will assume, as of the Effective Time, all obligations under the Progress Energy, Inc. Management Change-in-Control Plan, as amended and restated effective January 1, 2008 but after giving effect to the amendment of the definition of "Good Reason" set forth in Section 4.01(d)(iii) of the Progress Disclosure Letter (the "Progress CIC Plan") and (ii) a termination of employment from Duke and its affiliates shall be the same as a termination of employment from Progress and its affiliates for all purposes under the Progress CIC Plan.

(e) Prior to the Effective Time, Progress shall (i) amend the definition of Committee set forth in Section 2.9 of the Progress CIC Plan by deleting the last sentence of such definition in its entirety and (ii) either amend the Progress CIC Plan or prescribe terms in the applicable award agreement to provide that, except as set forth in Section 4.01(d)(iii) of the Progress Disclosure Letter, for all equity awards granted under the Progress Employee Stock Option Plans to participants in the Progress CIC Plan after the date hereof, the definition of "good reason" or similar concept of constructive termination relating to such awards shall be as defined in Section 4.01(d)(iii) of the Progress Disclosure Letter. Progress also acknowledges and agrees that (A) neither Progress nor any of its subsidiaries will take any actions to fund any grantor trust or similar vehicle that it currently maintains, or may maintain at any time following the date hereof, in connection with the transactions contemplated by this Agreement and (B) prior to the Effective Time, Progress will take all actions necessary to amend (x) any grantor trust maintained by Progress to eliminate any requirement to fund any such grantor trust in connection with the transactions contemplated by this Agreement and (y) any Progress Employee Benefit Plan requiring the establishment or funding of a grantor trust to eliminate such requirement.

(f) Duke acknowledges and agrees that it shall assume, as of the Effective Time, all obligations under the Amended and Restated Supplemental Senior Executive Retirement Plan of Progress Energy, Inc. (the "SERP"); provided that nothing herein shall prohibit Progress or its affiliates or their respective successors and assigns from modifying, amending or terminating the provisions of the SERP in any manner in accordance with its terms and applicable law; provided, further that no modification, amendment or termination shall adversely affect a participant's accrued benefit or the right to payment thereof under the provisions of the SERP as in effect immediately prior to such amendment, modification or termination. Without limiting the generality of the foregoing, following the Effective Time, in the event that the SERP is amended in a manner that would otherwise reduce a participant's right to accrue future benefits under the SERP, Duke shall provide such participant with the opportunity to earn additional benefits under the SERP (or another compensation or benefit arrangement) equal to no less than the incremental amount that the participant would have earned under the SERP (i.e., due to the accrual of additional years of Service (as defined in the SERP)) in the absence of such amendment, except that such incremental amount shall be calculated after treating the participant's Final Average Salary (as defined in the SERP) as if it was solely based on compensation earned by the participant prior to the Effective Time, as increased after the Effective Time by cost of living adjustments. Progress shall amend the SERP as soon as practicable after the date hereof to provide that no individual may become a participant in the SERP following the date of this Agreement.

(g) At the Effective Time, outstanding awards under the Progress Management Incentive Compensation Plan shall be assumed and the performance period for each such award shall remain open (such that no payments shall be made under the terms of the Progress

Management Incentive Compensation Plan solely as a result of or in connection with the Merger) at a level and providing an annual incentive compensation opportunity that is not less than the level and annual incentive compensation opportunity under the existing Progress Management Incentive Compensation Plan and the applicable performance criteria and vesting requirements for each such award shall be adjusted by the Compensation Committee of the Board of Directors of Duke as it determines is appropriate and equitable to reflect the performance of Progress during the performance period prior to the Effective Time, the transactions contemplated by this Agreement and the performance measures under awards made to similarly situated Duke employees as soon as practicable following the Effective Time.

(h) Without limiting the generality of Section 8.06, the provisions of this Section 5.07 are solely for the benefit of the parties to this Agreement, and no current or former director, officer, employee or independent contractor or any other person shall be a third-party beneficiary of this Agreement, and nothing herein shall be construed as an amendment to any Progress Employee Benefit Plan, Duke Employee Benefit Plan or other compensation or benefit plan or arrangement for any purpose.

Section 5.08 Indemnification, Exculpation and Insurance. (a) Each of Duke, Merger Sub and Progress agrees that, to the fullest extent permitted under applicable law, all rights to indemnification, advancement and exculpation from liabilities for acts or omissions occurring at or prior to the Effective Time now existing in favor of the current or former directors, officers and employees and the fiduciaries currently indemnified under benefit plans of Progress and its subsidiaries, as provided in their respective certificate or articles of incorporation, by-laws (or comparable organizational documents) or other agreements providing indemnification, advancement or exculpation shall survive the Merger and shall continue in full force and effect in accordance with their terms, and no such provision in any certificate or articles of incorporation, by-laws (or comparable organizational document) or other agreement shall be amended, modified or repealed in any manner that would adversely affect the rights or protections thereunder to any such individual with respect to acts or omissions occurring at or prior to the Effective Time. In addition, from and after the Effective Time, all directors, officers and employees and all fiduciaries currently indemnified under benefit plans of Progress or its subsidiaries who become directors, officers, employees or fiduciaries under benefit plans of Duke will be entitled to the indemnity, advancement and exculpation rights and protections afforded to directors, officers and employees or fiduciaries under benefit plans of Duke. From and after the Effective Time, Duke shall cause the Surviving Corporation and its subsidiaries to honor and perform, in accordance with their respective terms, each of the covenants contained in this Section 5.08 without limit as to time.

(b) For six years after the Effective Time, Duke shall maintain in effect the directors' and officers' liability (and fiduciary) insurance policies currently maintained by Progress covering acts or omissions occurring on or prior to the Effective Time with respect to those persons who are currently covered by Progress's respective directors' and officers' liability (and fiduciary) insurance policies on terms with respect to such coverage and in amounts no less favorable than those set forth in the relevant policy in effect on the date of this Agreement; provided that the annual cost thereof shall not exceed 300% of the annual cost of such policies as of the date hereof. If such no less favorable insurance coverage cannot be maintained for such cost, Duke shall maintain the most advantageous policies of directors' and officers' insurance otherwise obtainable for such cost. Prior to the Effective Time, Progress may purchase a six-year "tail" prepaid policy on terms and conditions no less advantageous to the Progress Indemnified Parties, or any other person entitled to the benefit of Sections 5.08(a) and (b), as applicable, than the existing directors' and officers' liability (and fiduciary) insurance maintained by Progress, covering without limitation the transactions contemplated hereby; provided that the aggregate cost thereof shall not exceed 600% of the annual cost of the directors' and officers' liability (and fiduciary) insurance maintained by Progress as of the date hereof. If such "tail" prepaid policy has been obtained by Progress prior to the Effective Time, it shall satisfy the obligations set forth in the first two sentences of this paragraph (b) and Duke shall, after the Effective Time, maintain such policy in full force and effect, for its full term, and continue to honor its obligations thereunder.

(c) From and after the Effective Time, Duke will cause the Surviving Corporation to indemnify and hold harmless each present director and officer of Progress or any of its subsidiaries (in each case, for acts or failures to act in such capacity), determined as of the date hereof, and any person who becomes such a director or officer between the date hereof and the Effective Time (collectively, the "Progress Indemnified Parties"), against any costs or expenses (including reasonable attorneys' fees, costs and expenses), judgments, fines, losses, claims, damages or liabilities incurred in connection with any claim, action, suit, proceeding or investigation, whether civil, criminal, administrative or investigative, arising out of matters existing or occurring at or prior to the Effective Time, whether asserted or claimed prior to, at or after the Effective Time (including any matters arising in connection with the transactions contemplated by this Agreement), to the fullest extent permitted by applicable law (and Duke will cause the Surviving Corporation to also advance expenses (including reasonable attorneys' fees, costs and expenses) as incurred to the fullest extent permitted under applicable law; provided that if required by applicable law the person to whom expenses are advanced provides an undertaking to repay such advances if it is ultimately determined that such person is not entitled to indemnification); and provided, further, that any determination as to whether a Progress Indemnified Party is entitled to indemnification or advancement of expenses hereunder pursuant to applicable law shall be made by independent counsel jointly selected by the Surviving Corporation and such Progress Indemnified Party.

(d) The obligations of Duke and the Surviving Corporation under this Section 5.08 shall not be terminated or modified by such parties in a manner so as to adversely affect any Progress Indemnified Party, or any other person entitled to the benefit of Sections 5.08(a) and (b), as the case may be, to whom this Section 5.08 applies without the consent of the affected Progress Indemnified Party, or such other person, as the case may be. If Duke, the Surviving Corporation or any of their respective successors or assigns (i) shall consolidate with or merge into any other corporation or entity and shall not be the continuing or surviving corporation or entity of such consolidation or merger or (ii) shall transfer all or substantially all of its properties and assets to any individual, corporation or other entity, then, and in each such case, proper provisions shall be made so that the successors and assigns of Duke or the Surviving Corporation, as the case may be, shall assume all of the obligations of Duke, or the Surviving Corporation, as the case may be, set forth in this Section 5.08.

(e) The provisions of Section 5.08 are (i) intended to be for the benefit of, and will be enforceable by, each indemnified party, his or her heirs and his or her representatives and (ii) in addition to, and not in substitution for, any other rights to indemnification, advancement, exculpation or contribution that any such person may have by contract or otherwise.

Section 5.09 Fees and Expenses. (a) Except as provided in this Section 5.09, all fees and expenses incurred in connection with the Merger, this Agreement and the transactions contemplated by this Agreement shall be paid by the party incurring such fees or expenses, whether or not the Merger is consummated, except that each of Progress and Duke shall each bear and pay one-half of the costs and expenses incurred in connection with (1) the filing, printing and mailing of the Form S-4 and the Joint Proxy Statement (including SEC filing fees), (2) the filings of the premerger notification and report forms under the HSR Act (including filing fees) and (3) the preparation and filing of all applications, filings or other materials with the FPSC, PUCO, the NCUC, the IURC, the KPSC and the PSCSC. The Surviving Corporation shall file any return with respect to, and shall pay, any state or local taxes (including penalties or interest with respect thereto), if any, that are attributable to (i) the transfer of the beneficial ownership of Progress's real property and (ii) the transfer of Progress Common Stock pursuant to this Agreement as a result of the Merger. Progress and Duke shall cooperate with respect to the filing of such returns, including supplying any information that is reasonably necessary to complete such returns.

(b) Progress shall immediately pay Duke a fee equal to $400 million (the "Progress Termination Fee") minus any amounts as may have been previously paid by Progress pursuant to Section 5.09(d), payable by wire transfer of same day funds, in the event that:

(i) following the Progress Shareholder Approval, (x) a Progress Takeover Proposal shall have been made known to Progress or any person shall have publicly announced an intention (whether or not conditional) to make a Progress Takeover Proposal, (y) thereafter this Agreement is terminated by Progress pursuant to Section 7.01(b)(i) and (z) within six months of such termination Progress or any of its subsidiaries enters into any Progress Acquisition Agreement or consummates any Progress Takeover Proposal, in either case with the person (or an affiliate of such person) that made the Progress Takeover Proposal referred to in clause (x), or

(ii) prior to or during the Progress Shareholders Meeting (or any subsequent meeting of Progress shareholders at which it is proposed that the Merger be approved), (x) a Progress Takeover Proposal shall have been publicly disclosed or any person shall have publicly announced an intention (whether or not conditional) to make a Progress Takeover Proposal, (y) thereafter this Agreement is terminated by either Progress or Duke pursuant to Section 7.01(b)(iii), and (z) within 12 months of such termination Progress or any of its subsidiaries enters into any Progress Acquisition Agreement or consummates any Progress Takeover Proposal, in either case with the person (or an affiliate of such person) that made the Progress Takeover Proposal referred to in clause (x), or

(iii) this Agreement is terminated by Progress pursuant to Section 7.01(d), or

(iv) this Agreement is terminated by Duke pursuant to Section 7.01(h)(i) , provided, however, that if this Agreement is terminated by Duke pursuant to Section 7.01(h)(i) as a result of the Board of Directors of Progress (or any committee thereof) having withdrawn or modified, or proposed publicly to withdraw or modify, the approval or recommendation by such Board of Directors of this Agreement or the Merger primarily due to adverse conditions, events or actions of or relating to Duke, the Progress Termination Fee shall not be payable to Duke, or

(v) this Agreement is terminated by Duke pursuant to 7.01(h)(iii).

For the purposes of Section 5.09(b)(i) and (ii), the terms "Progress Acquisition Agreement" and "Progress Takeover Proposal" shall have the meanings assigned to such terms in Section 4.03 (except that the references to "20%" in the definition of "Progress Takeover Proposal" in Section 4.03(a) shall be deemed to be references to "50%") and the Termination Fee shall be immediately payable upon the first to occur of Progress entering into such Progress Acquisition Agreement or consummating such Progress Takeover Proposal.

(c) Duke shall immediately pay Progress a fee equal to $675 million (the "Duke Termination Fee") minus any amounts as may have been previously paid by Duke pursuant to Section 5.09(e), payable by wire transfer of same day funds, in the event that:

(i) following the Duke Shareholder Approval, (x) a Duke Takeover Proposal shall have been made known to Duke or any person shall have publicly announced an intention (whether or not conditional) to make a Duke Takeover Proposal, (y) thereafter this Agreement is terminated by Duke pursuant to Section 7.01(b)(i), and (z) within six months of such termination Duke or any of its subsidiaries enters into any Duke Acquisition Agreement or consummates any Duke Takeover Proposal, in either case with the person (or an affiliate of such person) that made the Duke Takeover Proposal referred to in clause (x), or

(ii) prior to or during the Duke Shareholders Meeting (or any subsequent meeting of Duke shareholders at which it is proposed that the Duke Share Issuance or Duke Charter Amendment be approved), (x) a Duke Takeover Proposal shall have been publicly disclosed or any person shall have publicly announced an intention (whether or not conditional) to make a Duke Takeover Proposal, (y) thereafter this Agreement is terminated by either Progress or Duke pursuant to Section 7.01(b)(ii), and (z) within 12 months of such termination Duke or any of its subsidiaries enters into any Duke Acquisition Agreement or consummates any Duke Takeover Proposal, in either case with the person (or an affiliate of such person) that made the Duke Takeover Proposal referred to in clause (x), or

(iii) this Agreement is terminated by Duke pursuant to Section 7.01(f), or

(iv) this Agreement is terminated by Progress pursuant to Section 7.01(g)(i) , provided, however, that if this Agreement is terminated by Progress pursuant to Section 7.01(g)(i) as a result of the Board of Directors of Duke (or any committee thereof) having withdrawn or modified, or proposed publicly to withdraw or modify, the approval or recommendation by such Board of Directors of the Duke Share Issuance or Duke Charter Amendment primarily due to adverse conditions, events or actions of or relating to Progress, the Duke Termination Fee shall not be payable to Progress, or

(v) this Agreement is terminated by Progress pursuant to 7.01(g)(iii).

For the purposes of Section 5.09(c)(i) and (ii), the terms "Duke Acquisition Agreement" and "Duke Takeover Proposal" shall have the meanings assigned to such terms in Section 4.04 (except that the references to "20%" in the definition of "Duke Takeover Proposal" in Section 4.04(a) shall be deemed to be references to "50%") and the Duke Termination Fee shall be immediately payable upon the first to occur of Duke entering into such Duke Acquisition Agreement or consummating such Duke Takeover Proposal.

(d) If this Agreement is terminated (i) by Progress or Duke pursuant to Section 7.01(b)(iii) (after the public disclosure of a Progress Takeover Proposal or the announcement by any person of the intention (whether or not conditional) to make a Progress Takeover Proposal and in each case there shall not have been a bona fide withdrawal thereof prior to the Progress Shareholders Meeting) or (ii) by Duke pursuant to Section 7.01(e), Progress shall reimburse Duke promptly upon demand, but in no event later than three business days after the date of such demand, by wire transfer of same day funds, for all reasonable, out-of-pocket fees and expenses incurred or paid by or on behalf of, Duke in connection with the Merger or the transactions contemplated by this Agreement, including all reasonable fees and expenses of counsel, investment banking firms, accountants, experts and consultants to Duke; provided, however, that Progress shall not be obligated to make payments pursuant to this Section 5.09(d) in excess of $30,000,000 in the aggregate.

(e) If this Agreement is terminated (i) by Progress or Duke pursuant to Section 7.01(b)(ii) (after the public disclosure of a Duke Takeover Proposal or the announcement by any person of the intention (whether or not conditional) to make a Duke Takeover Proposal and in each case there shall not have been a bona fide withdrawal thereof prior to the Duke Shareholders Meeting), or (ii) by Progress pursuant to Section 7.01(c), Duke shall reimburse Progress promptly upon demand, but in no event later than three business days after the date of such demand, by wire transfer of same day funds, for all reasonable, out-of-pocket fees and expenses incurred or paid by or on behalf of, Progress in connection with the Merger or the transactions contemplated by this Agreement, including all reasonable fees and expenses of counsel, investment banking firms, accountants, experts and consultants to Progress; provided, however, that Duke shall not be obligated to make payments pursuant to this Section 5.09(e) in excess of $30,000,000 in the aggregate.

(f) Progress acknowledges that the agreements contained in Sections 5.09(b) and 5.09(d) are an integral part of the transactions contemplated by this Agreement, and that, without these agreements, Duke would not enter into this Agreement; accordingly, if Progress fails promptly to pay the amount due pursuant to Section 5.09(b) or 5.09(d), and, in order to obtain such payment, Duke commences a suit that results in a judgment against Progress for the fees set forth in Section 5.09(b) or 5.09(d), Progress shall pay to Duke its costs and expenses (including attorneys' fees and expenses) in connection with such suit, together with interest on the amount of the fee at the prime rate of Citibank N.A. in effect on the date such payment was required to be made.

(g) Duke acknowledges that the agreements contained in Sections 5.09(c) and 5.09(e) are an integral part of the transactions contemplated by this Agreement, and that, without these agreements, Progress would not enter into this Agreement; accordingly, if Duke fails promptly to pay the amount due pursuant to Section 5.09(c) or 5.09(e), and, in order to obtain such payment, Progress commences a suit that results in a judgment against Duke for the fees set forth in Section 5.09(c) or 5.09(e), Duke shall pay to Progress its costs and expenses (including attorneys' fees and expenses) in connection with such suit, together with interest on the amount of the fee at the prime rate of Citibank N.A. in effect on the date such payment was required to be made.

Section 5.10 Public Announcements. Progress and Duke will consult with each other before issuing, and provide each other the reasonable opportunity to review, comment upon and concur with, any press release or other public statements with respect to the transactions contemplated by this Agreement, including the Merger, and shall not issue any such press release or make any such public statement prior to such consultation, except as any party, after consultation with counsel, determines is required by applicable law or applicable rule or regulation of the NYSE.

Section 5.11 Affiliates. As soon as practicable after the date of this Agreement, Progress shall deliver to Duke, and Duke shall deliver to Progress, a letter identifying all persons who are, at the time this Agreement is submitted for adoption by the respective shareholders of Duke and Progress, "affiliates" of Progress or Duke, as the case may be, for purposes of Rule 145 under the Securities Act.

Section 5.12 NYSE Listing. Duke shall use its reasonable best efforts to cause the shares of Duke Common Stock issuable to Progress's shareholders as contemplated by this Agreement to be approved for listing on the NYSE, subject to official notice of issuance, as promptly as practicable after the date of this Agreement, and in any event prior to the Closing Date.

Section 5.13 Shareholder Litigation. Each of Progress and Duke shall give the other the reasonable opportunity to consult concerning the defense of any shareholder litigation against Progress or Duke, as applicable, or any of their respective directors or officers relating to the transactions contemplated by this Agreement.

Section 5.14 Tax-Free Reorganization Treatment. The parties to this Agreement intend that the Merger will qualify as a reorganization under Section 368(a) of the Code, and each shall not, and shall not permit any of their respective subsidiaries to, take any action, or fail to take any action, that would reasonably be expected to jeopardize the qualification of the Merger as a reorganization under Section 368(a) of the Code.

Section 5.15 Standstill Agreements; Confidentiality Agreements. During the period from the date of this Agreement through the Effective Time, neither Progress nor Duke shall terminate, amend, modify or waive any provision of any confidentiality or standstill agreement to which it or any of its respective subsidiaries is a party except (i) as required by applicable law, (ii) during the Progress Applicable Period in the case of Progress or during the Duke Applicable Period in the case of Duke, neither party shall enforce any standstill agreements or similar obligations in effect on the date of this Agreement in any manner that might prevent a third party from requesting permission to submit a Progress Takeover Proposal in accordance with Section 4.03 or a Duke Takeover Proposal in accordance with Section 4.04, as applicable or (iii) if the Board of Directors of the applicable party determines in good faith that failure to do so could reasonably be expected to result in a breach of its fiduciary obligations under applicable law. Except as provided in the first sentence of this Section 5.15, Progress or Duke, as the case may be, shall enforce any confidentiality or standstill agreement to which it or any of its respective subsidiaries is a party, including by seeking injunctions to prevent any breaches of such agreements and to enforce specifically the terms and provisions thereof, to the fullest extent permitted under applicable law.

ARTICLE VI

CONDITIONS PRECEDENT

Section 6.01 Conditions to Each Party's Obligation to Effect the Merger. The respective obligation of each party to effect the Merger is subject to the satisfaction or waiver by Progress and Duke on or prior to the Closing Date of the following conditions:

(a) Shareholder Approvals. Each of the Duke Shareholder Approval and the Progress Shareholder Approval shall have been obtained.

(b) No Injunctions or Restraints. No (i) temporary restraining order or preliminary or permanent injunction or other order by any federal or state court of competent jurisdiction preventing consummation of the Merger or (ii) applicable federal or state law prohibiting consummation of the Merger (collectively, "Restraints") shall be in effect.

(c) Form S-4. The Form S-4 shall have become effective under the Securities Act and shall not be the subject of any stop order or proceedings seeking a stop order and no proceedings for that purpose shall have been initiated or overtly threatened by the SEC.

(d) NYSE Listing. The shares of Duke Common Stock issuable to Progress's shareholders as contemplated by this Agreement shall have been approved for listing on the NYSE, subject to official notice of issuance.

(e) Charter Amendment. The Duke Charter Amendment shall have become effective.

Section 6.02 Conditions to Obligations of Progress. The obligation of Progress to effect the Merger is further subject to satisfaction or waiver of the following conditions:

(a) Representations and Warranties. The representations and warranties of Duke set forth herein shall be true and correct both when made and at and as of the Closing Date, as if made at and as of such time (except to the extent expressly made as of an earlier date, in which case as of such date), except where the failure of such representations and warranties to be so true and correct (without giving effect to any limitation as to "materiality" or "material adverse effect" set forth therein) does not have, and could not reasonably be expected to have, individually or in the aggregate, a material adverse effect on Duke.

(b) Performance of Obligations of Duke. Duke shall have performed in all material respects all obligations required to be performed by it under this Agreement at or prior to the Closing Date.

(c) Tax Opinion. Progress shall have received a written opinion from Hunton & Williams LLP, counsel to Progress, dated as of the Closing Date, to the effect that the Merger will qualify as a reorganization under Section 368(a) of the Code. Such counsel shall be entitled to rely upon representation letters from each of Duke, Progress, Merger Sub and others, in each case, in form and substance reasonably satisfactory to such counsel. Each such representation letter shall be dated as of the date of such opinion. The opinion condition referred to in this Section 6.02(c) shall not be waivable after receipt of the Progress Shareholder Approval, unless further approval of the shareholders of Progress is obtained with appropriate disclosure.

(d) Statutory Approvals. The Progress Required Statutory Approvals and the Duke Required Statutory Approvals shall have been obtained (including, in each case, the expiration or termination of the waiting periods (and any extensions thereof) under the HSR Act applicable to the Merger and the transactions contemplated by this Agreement) at or prior to the Effective Time, such approvals shall have become Final Orders (as defined below) and neither (i) such Final Orders nor (ii) any other order, action or regulatory condition of a regulatory body shall impose terms or conditions that, individually or in the aggregate, could reasonably be expected to have a Burdensome Effect on Progress or Duke. A "Final Order" means action by the relevant Governmental Authority that has not been reversed, stayed, enjoined, set aside, annulled or suspended, with respect to which any waiting period prescribed by law before the transactions contemplated hereby may be consummated has expired (a "Final Order Waiting Period"), and as to which all conditions to the consummation of such transactions prescribed by law, regulation or order have been satisfied.

(e) No Material Adverse Effect. Except as disclosed in the Duke SEC Reports filed on or after January 1, 2010 and prior to the date hereof or in any specific section of the Duke Disclosure Letter corresponding to Section 3.02, since December 31, 2009, there shall not have been any change, event, occurrence or development that, individually or in the aggregate, has had or could reasonably be expected to have a material adverse effect on Duke.

(f) Closing Certificates. Progress shall have received a certificate signed by an executive officer of Duke, dated the Effective Time, to the effect that, to such officer's knowledge, the conditions set forth in Sections 6.02(a), 6.02(b) and 6.02(e) have been satisfied.

Section 6.03 Conditions to Obligations of Duke. The obligation of Duke to effect the Merger is further subject to satisfaction or waiver of the following conditions:

(a) Representations and Warranties. The representations and warranties of Progress set forth herein shall be true and correct both when made and at and as of the Closing Date, as if made at and as of such time (except to the extent expressly made as of an earlier date, in which case as of such date), except where the failure of such representations and warranties to be so true and correct (without giving effect to any limitation as to "materiality" or "material adverse effect" set forth therein) does not have, and could not reasonably be expected to have, individually or in the aggregate, a material adverse effect on Progress.

(b) Performance of Obligations of Progress. Progress shall have performed in all material respects all obligations required to be performed by it under this Agreement at or prior to the Closing Date.

(c) Tax Opinion. Duke shall have received a written opinion from Wachtell, Lipton, Rosen & Katz, counsel to Duke, dated as of the Closing Date, to the effect that the Merger will qualify as a reorganization under Section 368(a) of the Code. Such counsel shall be entitled to rely upon representation letters from each of Duke, Progress, Merger Sub and others, in each case, in form and substance reasonably satisfactory to such counsel. Each such representation letter shall be dated as of the date of such opinion. The opinion condition referred to in this Section 6.03(c) shall not be waivable after receipt of the Duke Shareholder Approval, unless further approval of the shareholders of Duke is obtained with appropriate disclosure.

(d) Statutory Approvals. The Progress Required Statutory Approvals and the Duke Required Statutory Approvals shall have been obtained (including, in each case, the expiration or termination of the waiting periods (and any extensions thereof) under the HSR Act applicable to the Merger and the transactions contemplated by this Agreement) at or prior to the Effective Time, such approvals shall have become Final Orders and neither (i) such Final Orders nor (ii) any other order, action or regulatory condition of a regulatory body shall impose terms or conditions that, individually or in the aggregate, could reasonably be expected to have a Burdensome Effect on Duke or Progress.

(e) No Material Adverse Effect. Except as disclosed in the Progress SEC Reports filed on or after January 1, 2010 and prior to the date hereof or in any specific section of the Progress Disclosure Letter corresponding to Section 3.01, since December 31, 2009, there shall not have been any change, event, occurrence or development that, individually or in the aggregate, has had or could reasonably be expected to have a material adverse effect on Progress.

(f) Closing Certificates. Duke shall have received a certificate signed by an executive officer of Progress, dated the Effective Time, to the effect that, to such officer's knowledge, the conditions set forth in Sections 6.03(a), 6.03(b) and 6.03(e) have been satisfied.

Section 6.04 Frustration of Closing Conditions. Neither Progress nor Duke may rely on the failure of any condition set forth in Section 6.01, 6.02 or 6.03, as the case may be, to be satisfied if such failure was caused by such party's failure to use reasonable best efforts to consummate the Merger and the other transactions contemplated by this Agreement, to the extent required by and subject to Section 5.05.

ARTICLE VII

TERMINATION, AMENDMENT AND WAIVER

Section 7.01 Termination. This Agreement may be terminated at any time prior to the Effective Time, whether before or (other than pursuant to clauses (d), (f), (g) or (h) below) after the Progress Shareholder Approval or the Duke Shareholder Approval:

(a) by mutual written consent of Progress and Duke;

(b) by either Progress or Duke:

(i) if the Merger shall not have been consummated by the 12-month anniversary of the date of this Agreement (the "Initial Termination Date"); provided, however, that the right to terminate this Agreement pursuant to this Section 7.01(b)(i) shall not be available to any party whose failure to perform any of its obligations under this Agreement results in the failure of the Merger to be consummated by such time; and provided, further, that, (A) if on the Initial Termination Date the conditions to the Closing set forth in Sections 6.01(b), 6.02(d) and/or 6.03(d) shall not have been fulfilled but all other conditions to the Closing shall have been fulfilled or shall be capable of being fulfilled, then either party may (on one or more occasions) extend the Initial Termination Date up to the 18-month anniversary of the date of this Agreement and (B) if the Initial Termination Date (as it may be extended pursuant to clause (A) of this Section 7.01(b)(i)) shall occur during any Final Order Waiting Period, the Initial Termination Date shall be extended until the third business day after the expiration of such Final Order Waiting Period;

(ii) if the Duke Shareholder Approval shall not have been obtained at a Duke Shareholders Meeting duly convened therefor or at any adjournment or postponement thereof;

(iii) if the Progress Shareholder Approval shall not have been obtained at a Progress Shareholders Meeting duly convened therefor or at any adjournment or postponement thereof;

(iv) if any Restraint having any of the effects set forth in Section 6.01(b) shall be in effect and shall have become final and nonappealable; provided that the party seeking to terminate this Agreement pursuant to this Section 7.01(b)(iv) shall have used its reasonable best efforts to prevent the entry of and to remove such Restraint; or

(v) if any condition to the obligation of such party to consummate the Merger set forth in Section 6.02 (in the case of Progress) or in Section 6.03 (in the case of Duke) becomes incapable of satisfaction prior to the Initial Termination Date (or, if the Initial Termination Date is extended in accordance with the second proviso to Section 7.01(b)(i), such date as extended); provided, however, in the case of Section 6.02(d) and 6.03(d), the Initial Termination Date shall refer to such date as it may be extended pursuant to the second proviso to Section 7.01(b)(i); and provided further, that the failure of any such condition to be capable of satisfaction is not the result of a material breach of this Agreement by the party seeking to terminate this Agreement;

(c) by Progress, if Duke shall have breached or failed to perform in any material respect any of its representations, warranties, covenants or other agreements contained in this Agreement, which breach or failure to perform (A) would give rise to the failure of a condition set forth in Section 6.02(a) or (b), and (B) is incapable of being cured by Duke or is not cured by Duke within 60 days following receipt of written notice from Progress of such breach or failure to perform;

(d) by Progress in accordance with Section 4.03(b); provided, that, in order for the termination of this Agreement pursuant to this paragraph (d) to be deemed effective, Progress shall have complied with Section 4.03 and with applicable requirements, including the payment of the Progress Termination Fee, of Section 5.09;

(e) by Duke, if Progress shall have breached or failed to perform in any material respect any of its representations, warranties, covenants or other agreements contained in this Agreement, which breach or failure to perform (A) would give rise to the failure of a condition set forth in Section 6.03(a) or (b), and (B) is incapable of being cured by Progress or is not cured by Progress within 60 days following receipt of written notice from Duke of such breach or failure to perform;

(f) by Duke in accordance with Section 4.04(b); provided, that, in order for the termination of this Agreement pursuant to this paragraph (f) to be deemed effective, Duke shall have complied with Section 4.04 and with applicable requirements, including the payment of the Duke Termination Fee, of Section 5.09;

(g) by Progress, if the Board of Directors of Duke (or any committee thereof) (i) shall have withdrawn or modified, or proposed publicly to withdraw or modify, the approval or recommendation by such Board of Directors of the Duke Charter Amendment or the Duke Share Issuance, (ii) shall fail to reaffirm such approval or recommendation within 15 business days of receipt of Progress's written request at any time when a Duke Takeover Proposal shall have been made and not rejected by the Board of Directors of Duke; provided, that, such 15-business day period shall be extended for ten business days following any material modification to such Duke Takeover Proposal occurring after the receipt of Progress's written request and provided, further, that such 15-business day period shall recommence each time a Duke Takeover Proposal has been made following the receipt of Progress's written request by a person that had not made a Duke Takeover Proposal prior to the receipt of Progress's written request, or (iii) shall have approved or recommended, or proposed to approve or recommend, a Duke Takeover Proposal; or

(h) by Duke, if the Board of Directors of Progress (or any committee thereof) (i) shall have withdrawn or modified, or proposed publicly to withdraw or modify, the approval or recommendation by such Board of Directors of this Agreement or the Merger, (ii) shall fail to reaffirm such approval or recommendation within 15 business days of receipt of Duke's written request at any time when a Progress Takeover Proposal shall have been made and not rejected by the Board of Directors of Progress; provided, that, such 15-business day period shall be extended for ten business days following any material modification to such Progress Takeover Proposal occurring after the receipt of Duke's written request and provided, further, that such 15-business day period shall recommence each time a Progress Takeover Proposal has been made following the receipt of Duke's written request by a person that had not made a Progress Takeover Proposal prior to the receipt of Duke's written request, or (iii) shall have approved or recommended, or proposed to approve or recommend, a Progress Takeover Proposal.

Section 7.02 Effect of Termination. (a) In the event of termination of this Agreement by either Duke or Progress as provided in Section 7.01, this Agreement shall forthwith become null and void and have no effect, without any liability or obligation on the part of Progress or Duke, other than the provisions of Section 5.09, this Section 7.02 and Article VIII, which provisions shall survive such termination, and except to the extent that such termination results from the willful and material breach by a party of any of its representations, warranties, covenants or agreements set forth in this Agreement, in which case such termination shall not relieve any party of any liability or damages resulting from its willful and material breach of this Agreement (including any such case in which a Progress Termination Fee or a Duke Termination Fee, as the case may be, is, or any expenses of Progress or Duke in connection with the transactions contemplated by this Agreement are, payable pursuant to Section 5.09 to Progress or Duke, as the case may be (the "Injured Party"), to the extent any such liability or damage suffered by the Injured Party exceeds the amount of the Progress Termination Fee, in the circumstance in which Duke is the Injured Party, or the Duke Termination Fee, in the circumstance in which Progress is the Injured Party and any expenses payable pursuant to Section 5.09 to the Injured Party, it being the intent that any Progress Termination Fee, Duke Termination Fee and any expenses paid to the Injured Party shall serve as a credit against and off-set any liability or damage suffered by the Injured Party to the extent of such payment).

(b) In the event Duke terminates this Agreement pursuant to Section 7.01(h)(i) as a result of the Board of Directors of Progress having withdrawn or modified, or proposed to publicly withdraw or modify, the approval or recommendation by such Board of Directors of this Agreement or the Merger that was made primarily due to adverse conditions, events or actions of or relating to Duke, in any judicial, court or tribunal proceeding in which the payment of the Progress Termination Fee is at issue under the proviso in Section 5.09(b)(iv), whether brought or initiated by Duke or Progress, Progress shall have the burden of proving that the Board of Directors of Progress withdrew or modified, or proposed publicly to withdraw or modify, the approval or recommendation by such Board of Directors of this Agreement or the Merger primarily due to adverse conditions, events or actions of or relating to Duke.

(c) In the event Progress terminates this Agreement pursuant to Section 7.01(g)(i) as a result of the Board of Directors of Duke having withdrawn or modified, or proposed to publicly withdraw or modify, the approval or recommendation by such Board of Directors of the Duke Share Issuance and the Duke Charter Amendment that was made primarily due to adverse conditions, events or actions of or relating to Progress, in any judicial, court or tribunal proceeding in which the payment of the Duke Termination Fee is at issue under the proviso in Section 5.09(c)(iv), whether brought or initiated by Progress or Duke, Duke shall have the burden of proving that the Board of Directors of Duke withdrew or modified, or proposed publicly to withdraw or modify, the approval or recommendation by such Board of Directors of the Duke Share Issuance and the Duke Charter Amendment primarily due to adverse conditions, events or actions of or relating to Progress.

Section 7.03 Amendment. This Agreement may be amended by the parties at any time before or after the Duke Shareholder Approval or the Progress Shareholder Approval; provided, however, that after any such approval, there shall not be made any amendment that by law requires further approval by the shareholders of Duke or Progress without the further approval of such shareholders. This Agreement may not be amended except by an instrument in writing signed on behalf of each of the parties.

Section 7.04 Extension; Waiver. At any time prior to the Effective Time, a party may (a) extend the time for the performance of any of the obligations or other acts of the other parties, (b) waive any inaccuracies in the representations and warranties of the other parties contained in this Agreement or in any document delivered pursuant to this Agreement or (c) subject to the proviso of Section 7.03, waive compliance by the other parties with any of the agreements or conditions contained in this Agreement. Any agreement on the part of a party to any such extension or waiver shall be valid only if set forth in an instrument in writing signed on behalf of such party. The failure of any party to this Agreement to assert any of its rights under this Agreement or otherwise shall not constitute a waiver of such rights.

ARTICLE VIII

GENERAL PROVISIONS

Section 8.01 Nonsurvival of Representations and Warranties. None of the representations and warranties in this Agreement or in any instrument delivered pursuant to this Agreement shall survive the Effective Time. This Section 8.01 shall not limit any covenant or agreement of the parties that by its terms contemplates performance after the Effective Time and such provisions shall survive the Effective Time.

Section 8.02 Notices. All notices, requests, claims, demands and other communications under this Agreement shall be in writing and shall be deemed given (as of the time of delivery or, in the case of a telecopied communication, of confirmation) if delivered personally, telecopied (which is confirmed) or sent by overnight courier (providing proof of delivery) to the parties at the following addresses (or at such other address for a party as shall be specified by like notice):

if to Duke, to:

Duke Energy Corporation
526 South Church Street
Charlotte, North Carolina 28202
Telecopy No.: (704) 382-7705
Attention: Marc E. Manly

with a copy to:

Wachtell, Lipton, Rosen & Katz
51 West 52nd Street
New York, New York 10019
Telecopy No.: (212) 403-2000
Attention: Steven A. Rosenblum

if to Progress, to:

Progress Energy, Inc.
410 S. Wilmington Street
Raleigh, North Carolina 27602
Telecopy No.: (919) 546-5245
Attention: John R. McArthur

with a copy to:

Hunton & Williams LLP
200 Park Avenue
New York, New York 10166
Telecopy No.: (212) 309-1100
Attention: James A. Jones, III

and

Hunton & Williams LLP
One Bank of America Plaza, Suite 1400
421 Fayetteville Street
Raleigh, North Carolina 27601
Telecopy No.: (919) 833-6352
Attention: Timothy S. Goettel

Section 8.03 Definitions. For purposes of this Agreement:

(a) an "affiliate" of any person means another person that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such first person, where "control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management policies of a person, whether through the ownership of voting securities, by contract, as trustee or executor, or otherwise;

(b) "capital stock" or "shares of capital stock" means (i) with respect to a corporation, as determined under the laws of the jurisdiction of organization of such entity, capital stock or such shares of capital stock; (ii) with respect to a partnership, limited liability company, or similar entity, as determined under the laws of the jurisdiction of organization of such entity, units, interests, or other partnership or limited liability company interests; or (iii) any other equity ownership or participation;

(c) "Contract" means any legally binding written or oral agreement, contract, subcontract, lease, instrument, note, license or sublicense;

(d) "material adverse effect" means, when used in connection with Progress or Duke, as the case may be, any change, effect, event, occurrence or state of facts (i) that is materially adverse to the business, assets, properties, financial condition or results of operations of such person and its subsidiaries taken as a whole but excluding any of the foregoing resulting from (A) changes in international or national political or regulatory conditions generally (in each case, to the extent not disproportionately affecting the applicable person and its subsidiaries, taken as a whole, as compared to similarly situated persons), (B) changes or conditions generally affecting the U.S. economy or financial markets or generally affecting any of the segments of the industry in which the applicable person or any of its subsidiaries operates (in each case, to the extent not disproportionately affecting the applicable person and its subsidiaries, taken as a whole, as compared to similarly situated persons), (C) the announcement or consummation of, or compliance with, this Agreement, or (D) any taking of any action by such party at the written request of the other party, or (ii) that prevents or materially delays such person from performing its material obligations under this Agreement or consummation of the transactions contemplated hereby;

(e) "person" means an individual, corporation, partnership, limited liability company, joint venture, association, trust, unincorporated organization or other entity;

(f) "subsidiary" means, with respect to any person, any other person, whether incorporated or unincorporated, of which more than 50% of either the equity interests in, or the voting control of, such other person is, directly or indirectly through subsidiaries or otherwise, beneficially owned by such first person; and

(g) "knowledge" means (i) with respect to Progress, the actual knowledge of the persons listed in Section 8.03(g) of the Progress Disclosure Letter, and (ii) with respect to Duke, the actual knowledge of the persons listed in Section 8.03(g) of the Duke Disclosure Letter.

Section 8.04 Interpretation and Other Matters. (a) When a reference is made in this Agreement to an Article, Section or Exhibit, such reference shall be to an Article or Section of, or an Exhibit to, this Agreement unless otherwise indicated. The table of contents and headings contained in this Agreement are for reference purposes only and shall not affect in any way the meaning or interpretation of this Agreement. Whenever the words "include," "includes" or "including" are used in this Agreement, they shall be deemed to be followed by the words "without limitation." The words "hereof," "herein" and "hereunder" and words of similar import when used in this Agreement shall refer to this Agreement as a whole and not to any particular provision of this Agreement. All terms defined in this Agreement shall have the defined meanings when used in any certificate or other document made or delivered pursuant hereto unless otherwise defined therein. The definitions contained in this Agreement are applicable to the singular as well as the plural forms of such terms and to the masculine as well as to the feminine and neuter genders of such terms. Any agreement, instrument or statute defined or referred to herein or in any agreement or instrument that is referred to herein means such agreement, instrument or statute as from time to time amended, modified or supplemented, including (in the case of agreements or instruments) by waiver or consent and (in the case of statutes) by succession of comparable successor statutes and references to all attachments thereto and instruments incorporated therein. References to a person are also to its permitted successors and assigns.

(b) Each of Duke and Progress has or may have set forth information in its respective disclosure letter in a section thereof that corresponds to the section of this Agreement to which it relates. A matter set forth in one section of a disclosure letter need not be set forth in any other section of the disclosure letter so long as its relevance to the latter section of the disclosure letter or section of this Agreement is readily apparent on the face of the information disclosed in the disclosure letter to the person to which such disclosure is being made. The fact that any item of information is disclosed in a disclosure letter to this Agreement shall not be construed to mean that such information is required to be disclosed by this Agreement. Such information and the dollar thresholds set forth herein shall not be used as a basis for interpreting the terms "material," "material adverse effect" or other similar terms in this Agreement.

(c) Duke agrees to cause Merger Sub to comply with its obligations under this Agreement.

Section 8.05 Counterparts. This Agreement may be executed in one or more counterparts, all of which shall be considered one and the same agreement and shall become effective when one or more counterparts have been signed by each party and delivered to the other parties.

Section 8.06 Entire Agreement; No Third-Party Beneficiaries. This Agreement (including the documents and instruments referred to herein) and the Confidentiality Agreement (i) constitute the entire agreement, and supersede all prior agreements and understandings, both written and oral, among the parties with respect to the subject matter of this Agreement and (ii) except for the provisions of Section 5.08 (which shall be enforceable by the Indemnified Parties) and except for the rights of Progress's shareholders to receive the Merger Consideration after the Effective Time in the event the Merger is consummated, are not intended to confer upon any person other than the parties any rights or remedies. The representations and warranties in this Agreement are the product of negotiations among the parties and are for the sole benefit of the parties. Any inaccuracies in such representations and warranties are subject to waiver by the parties in accordance with the terms of this Agreement without notice or liability to any other person. The representations and warranties in this Agreement may represent an allocation among the parties of risks associated with particular matters regardless of the knowledge of any of the parties and may have been qualified by certain disclosures not reflected in the text of this Agreement. Accordingly, persons other than the parties may not rely upon the representations and warranties in this Agreement as characterizations of actual facts or circumstances as of the date of this Agreement or as of any other date.

Section 8.07 Governing Law. This Agreement shall be governed by, and construed in accordance with, the laws of the State of Delaware, regardless of the laws that might otherwise govern under applicable principles of conflict of laws, except that matters related to the fiduciary obligations of the Progress Board of Directors shall be governed by the laws of the State of North Carolina.

Section 8.08 Assignment. Neither this Agreement nor any of the rights, interests or obligations under this Agreement shall be assigned, in whole or in part, by operation of law or otherwise by any of the parties hereto without the prior written consent of the other party. Any attempted or purported assignment in violation of the preceding sentence shall be null and void and of no effect whatsoever. Subject to the preceding two sentences, this Agreement shall be binding upon, inure to the benefit of, and be enforceable by, the parties and their respective successors and assigns.

Section 8.09 Enforcement.

(a) The parties agree that irreparable damage would occur and that the parties would not have any adequate remedy at law in the event that any of the provisions of this Agreement were not performed in accordance with their specific terms or were otherwise breached. It is accordingly agreed that the parties shall be entitled to an injunction or injunctions to prevent breaches of this Agreement and to enforce specifically the terms and provisions of this Agreement, without the necessity of posting bonds or similar undertakings in connection therewith, this being in addition to any other remedy to which they are entitled at law or in equity.

(b) Each of the parties (i) irrevocably submits itself to the personal jurisdiction of each state or federal court sitting in the State of Delaware, as well as to the jurisdiction of all courts to which an appeal may be taken from such courts, in any suit, action or proceeding arising out of or relating to this Agreement or any of the transactions contemplated herein, (ii) agrees that every such suit, action or proceeding shall be brought, heard and determined exclusively in the Court of

Chancery of the State of Delaware (provided that, in the event subject matter jurisdiction is unavailable in or declined by the Court of Chancery, then all such claims shall be brought, heard and determined exclusively in any other state or federal court sitting in the State of Delaware), (iii) agrees that it shall not attempt to deny or defeat such personal jurisdiction by motion or other request for leave from such court, (iv) agrees not to bring any suit, action or proceeding arising out of or relating to this Agreement or any of the transactions contemplated herein in any other court, and (v) waives any defense of inconvenient forum to the maintenance of any suit, action or proceeding so brought.

(c) Each of the parties agrees that service of any process, summons, notice or document by U.S. registered mail to its address set forth in Section 8.02 shall be effective service of process for any action, suit or proceeding brought against it, provided, however, that nothing contained in the foregoing clause shall affect the right of any party to serve legal process in any other manner permitted by applicable Law.

Section 8.10 Severability. If any term or other provision of this Agreement is invalid, illegal or incapable of being enforced by any rule of law or public policy, all other conditions and provisions of this Agreement shall nevertheless remain in full force and effect. Upon such determination that any term or other provision is invalid, illegal or incapable of being enforced, the parties hereto shall negotiate in good faith to modify this Agreement so as to effect the original intent of the parties as closely as possible to the fullest extent permitted by applicable law in an acceptable manner to the end that the transactions contemplated hereby are fulfilled to the extent possible.

Section 8.11 Waiver of Jury Trial. Each party to this Agreement knowingly and voluntarily waives, to the fullest extent permitted by applicable law, any right it may have to a trial by jury in respect of any action, suit or proceeding arising out of or relating to this Agreement.

IN WITNESS WHEREOF, Duke, Merger Sub and Progress have caused this Agreement to be signed by their respective officers thereunto duly authorized, all as of the date first written above.

DUKE ENERGY CORPORATION

By James E Rogers
Name: James E. Rogers
Title: Chairman, President and chief Executive Officer

DIAMOND ACQUISITION CORPORATION

By [signature]
Name: David S. Maltz
Title: Vice President

PROGRESS ENERGY, INC.

By ______________________
Name:
Title:

IN WITNESS WHEREOF, Duke, Merger Sub and Progress have caused this Agreement to be signed by their respective officers thereunto duly authorized, all as of the date first written above.

DUKE ENERGY CORPORATION

By ______________________________
Name:
Title:

DIAMOND ACQUISITION CORPORATION

By ______________________________
Name:
Title:

PROGRESS ENERGY, INC.

By William D. Johnson
William D. Johnson
Chairman, President and Chief Executive Officer

Exhibit A

1. As of the Effective Time, the size of the Board of Directors of Duke will be increased to 18.

2. All 11 current directors of Duke (the "Duke Designees") will continue as directors as of the Effective Time, subject to their ability and willingness to serve. Seven of the current directors of Progress (the "Progress Designees") will be added to the Board of Directors of Duke as of the Effective Time, subject to their ability and willingness to serve, such seven directors to be designated by Progress, following reasonable consultation with Duke, no later than March 20, 2011.

3. If any Duke Designee is unable or unwilling to serve as a director of Duke as of the Effective Time, Duke will designate a replacement, following reasonable consultation with Progress, which replacement shall be deemed a Duke Designee for all purposes of the Merger Agreement.

4. If any Progress Designee is unable or unwilling to serve as a director of Duke as of the Effective Time, Progress will designate a replacement, following reasonable consultation with Duke, which replacement shall be deemed a Progress Designee for all purposes of the Merger Agreement.

5. As of the Effective Time, the standing Board committees of Duke will consist of Duke's existing committees plus a Regulatory Policy and Operations Committee. At least one Progress Designee will serve on each committee. In determining and recommending committee assignments, the Board and the Corporate Governance Committee will take into account, among other things, the skills and expertise of the directors, the needs of the committees, and the goal that committee workloads be distributed reasonably among the full Board.

6. Progress will designate the chairs of the Compensation Committee and the Audit Committee, and Duke will designate the chairs of each of the other Board committees, in each case following reasonable consultation with the other party, and in each case subject to such individuals' ability and willingness to serve. If any such designated chair is unable or unwilling to serve in such position as of the Effective Time, the party that designated such chair shall designate a replacement from among such party's director designees, following reasonable consultation with the other party.

7. Duke will designate the lead independent director, following reasonable consultation with Progress, subject to such individual's ability and willingness to serve. If the individual so designated as lead independent director is unable or unwilling to serve in such position as of the Effective Time, Duke will designate a replacement from among the Duke Designees, following reasonable consultation with Progress.

8. Prior to the Effective Time, Duke will amend its Principles for Corporate Governance to provide that the normal retirement date for directors will be the annual meeting held in the calendar year following the calendar year in which such director reaches the age of 71.

Exhibit B

Roles and Responsibilities

Chief Executive Officer	**Executive Chairman**
• Member of the Board • Determines Board agenda • Conduit between Duke and Board	• Conducts Board meetings • Supports Board selection process • Assists in setting Board agenda
• Develops the strategic plan • Develops and communicates vision & mission • Develops public policy positions	• Provides input on public policy positions • Spokesman on public policy initiatives ➢ National and international policy ➢ Global initiatives ➢ Active role in national and state government relations, in coordination with CEO
• Jointly designates executive management team with Executive Chairman prior to announcement • Following transition, selects executive management team with input from Executive Chairman	• Jointly designates executive management team with CEO prior to announcement • Following transition, provides input on selection of executive management team
• Develops annual budget for Board approval • Drives strategic financial and operational results • Leads the organization • Represents Duke to the public and investors	• Represents the Board to the public

Overview of responsibilities				
	Primary responsibility		Secondary responsibility	
	Executive Chairman	CEO	Executive Chairman	CEO
• Market/public communications				
• Before federal or international authorities	√			√
• Before state authorities		√	√	
• Rate proceedings		√		
• Financial/earnings call/strategy/ appearance at EEI and other industry conferences		√		
• National media on federal/global energy policy	√			√
• Point of contact for merger activities		√	√	
• Responsibility to determine Board agenda		√	√	
• Operational execution		√		
• Corporate strategy		√	√	

Exhibit C

**EMPLOYMENT AGREEMENT
TERM SHEET
WILLIAM D. JOHNSON**

As soon as reasonably practicable following the execution of this term sheet but in any event prior to the effective date of the closing of the merger (the "Merger") contemplated by the Agreement and Plan of Merger by and among Duke Energy Corporation ("Duke"), Progress Energy, Inc. ("Progress") and Diamond Acquisition Corporation (the "Merger Agreement"), Duke will take such action (or cause its affiliates to take such action) as may be necessary and appropriate to effectuate a new employment agreement to be entered into or assumed by Duke for William D. Johnson (the "Executive"), which agreement shall take effect as of the Merger. Effective upon the closing of the Merger and until such time as a new employment agreement becomes effective, this term sheet shall govern the respective parties' rights and obligations and shall constitute an amendment of the Executive's employment agreement when deemed effective as provided herein. The new employment agreement shall be governed by the following provisions.

1. Basic Premise – The new employment agreement shall be substantially similar to the form of the current employment agreement for Duke's current CEO, except as otherwise described below.

2. Role – The Executive shall be named as President and CEO of Duke effective upon the Merger, which will require conforming changes to the new employment agreement.

3. Term – Three-year term of employment commencing upon the closing of the Merger.

4. Ongoing Compensation

   (a) Annual Base Salary – $1,100,000.

   (b) Short-Term Incentive Plan – The Executive shall be eligible to participate in the applicable Duke short-term incentive plan, with a target opportunity of 125% of annual base salary. The terms and conditions of the Executive's short-term incentive compensation opportunities shall be substantially similar to the short-term incentive compensation opportunities provided to other executive officers of Duke, as determined by the Duke Compensation Committee from time to time.

   (c) Long-Term Incentives – The Executive shall be eligible to participate in the applicable Duke long-term incentive plan, with a target opportunity of 500% of annual base salary. The terms and conditions (e.g., performance measures, vesting schedules, allocation between performance and phantom shares) of the Executive's long-term incentive awards shall be substantially similar to the long-term incentive awards granted to other executive officers of Duke, as determined by the Duke Compensation Committee from time to time.

(d) Adjustments – Given the time period between the effective date of this term sheet and the anticipated date of the closing of the Merger, the Duke Compensation Committee will review benchmark data and reserves discretion to increase the compensation of the Executive if determined to be appropriate after taking into account the compensation provided to CEOs of Duke's peer group.

(e) Employee Benefits – The Executive shall be entitled to employee benefits (e.g., retirement plans, health and insurance plans, perquisites) as determined by the Duke Compensation Committee from time to time.

(f) SERP – The Executive's benefit under the Amended and Restated Supplemental Senior Executive Retirement Plan of Progress Energy, Inc. (the "SERP") shall be treated in the same manner as the benefit of other executives in the SERP who are employed with Duke following the closing of the Merger.

5. Impact of Termination of Employment

(a) If the Executive is involuntarily terminated without cause or quits for good reason following, but prior to the second anniversary of, the closing of the Merger, he will be entitled to severance equal to the benefits provided under the Progress Energy Inc. Management Change-in-Control Plan, as amended from time to time, except that no tax gross-up shall be provided, and the parties shall use their best efforts to structure the severance in a manner that eliminates or reduces the impact of Sections 280G and 4999 of the tax code.

(b) If the Executive is involuntarily terminated without cause or quits for good reason following the second anniversary of, but prior to the third anniversary of, the closing of the Merger, he will be entitled to the severance provided under his current employment agreement, as amended from time to time.

(c) For purposes of determining whether the Executive has "good reason" to terminate employment or a "constructive termination" has occurred, his move to Charlotte, NC, Sections 2.13(b) and 2.13(c) of the Progress Energy, Inc. Management Change-in-Control Plan and Section 8(a)(i) of his current employment agreement, shall be disregarded.

6. Other Matters

(a) Relocation Benefits – The Executive will be reimbursed for direct and indirect relocation costs, provided that the Executive shall not receive a tax gross-up or indemnification for any such relocation costs that constitute income to the Executive.

(b) Advisor Fees – The Executive will be reimbursed for reasonable expenses incurred in connection with the negotiation of this term sheet and the new employment agreement.

(c) <u>Corporate Aircraft</u> - The Executive will be subject to substantially the same policies as currently in effect for Duke's current CEO.

IN WITNESS WHEREOF, the parties signing below have executed this term sheet this ___ day of January, 2011, intending to be legally bound thereby.

DIAMOND ACQUISITION CORPORATION

By: ___________________________________

DUKE ENERGY CORPORATION

By: ___________________________________

____
William D. Johnson

Exhibit D

TERM SHEET FOR AMENDMENT TO EMPLOYMENT AGREEMENT JAMES E. ROGERS

As soon as reasonably practicable following the execution of this term sheet, but in any event prior to the Effective Time of the Merger contemplated by the Agreement and Plan of Merger by and among Duke Energy Corporation, Progress Energy, Inc. and Diamond Acquisition Corporation (the "Merger Agreement"), James E. Rogers (the "Executive") and Duke will each use their commercially reasonable efforts to amend (or cause their respective affiliates to amend) the employment agreement by and between the Executive and Duke, dated as of February 19, 2009 (the "Current Agreement"), as may be necessary and appropriate to effectuate the terms of the Executive's employment following the Merger that are set forth below, which amendments shall take effect as of the Effective Time. Capitalized terms used but not defined herein shall have the meanings ascribed to such terms in the Merger Agreement.

1. Current Agreement – Except as otherwise described below, the Current Agreement shall remain in full force and effect.

2. Role and Responsibilities – The Executive shall serve as Executive Chairman of the Board of Directors of Duke (the "Executive Chair") following the Merger and will cease to be employed as President and Chief Executive Officer of Duke as of the Effective Time. The Executive will continue to report directly to the Board of Directors of Duke and his roles and responsibilities will be those set forth on **Exhibit B** to the Merger Agreement. In no event will the foregoing amendments to the Current Agreement provide the Executive with the right to terminate his employment for "Good Reason" (as defined in the Current Agreement) under Section 10(b) of the Current Agreement.

3. Term – The Executive's term of employment will end on the later of (i) December 31, 2013 and (ii) the second anniversary of the Effective Time, unless terminated earlier pursuant to the terms of the Current Agreement.

4. Ongoing Compensation – The Executive's compensation will remain the same in all respects as under the Current Agreement through December 31, 2013. Should the term of employment continue beyond December 31, 2013 and the Executive continue to serve as Executive Chair as of that date, the Compensation Committee of the Board of Directors of Duke will address the Executive's compensation for the remaining term of his employment at that time.

5. Advisor Fees – The Executive will be reimbursed for reasonable expenses incurred in connection with the negotiation of this term sheet and the amendment to the Current Agreement.

IN WITNESS WHEREOF, the parties signing below have executed this term sheet this ___ day of January, 2011, intending to be legally bound thereby.

DIAMOND ACQUISITION CORPORATION

By: ___________________________________

DUKE ENERGY CORPORATION

By: ___________________________________

____
James E. Rogers

Exhibit E

Individual	**Position**
Lynn Good	Chief Financial Officer
Dhiaa Jamil	Nuclear Generation
Jeff Lyash	Energy Supply
Marc Manly	General Counsel, Corporate Secretary
John McArthur	Regulated Utilities
Mark Mulhern	Chief Administrative Officer
Keith Trent	Commercial Businesses
Jennifer Weber	Human Resources
Lloyd Yates	Customer Operations

In addition, A.R. Mullinax and Paula Sims shall co-lead integration during the transition period following Closing.