Progress Energy

Progress Energy Carolinas Integrated Resource Plan

September 1, 2008

Progress Energy

September 2, 2008

Mr. Charles Terreni
Chief Clerk and Administrator
South Carolina Public Service Commission
Post Office Drawer 11649
Columbia, South Carolina 29211

Re: Progress Energy Carolinas, Inc.
2008 Resource Plan
Docket No. 2006-174-E

Dear Mr. Terreni:

Pursuant to Section 58-37-40 of the Code of Laws of South Carolina, Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC") hereby submits for filing its 2008 Resource Plan. Some of the appendices to the Resource Plan contain confidential data. Accordingly, PEC will provide to the Commission via overnight service one copy of the confidential data in an envelope stamped "Confidential." PEC respectfully requests that the Commission treat this data as confidential and protect it from public disclosure. PEC will make this information available to other parties pursuant to an appropriate nondisclosure agreement.

Sincerely,

Len S. Anthony (by dhs)

Len S. Anthony
General Counsel
Progress Energy Carolinas, Inc.

Enclosures
55006
c: John Clark, State Energy Office
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Overview

Progress Energy Carolinas', Inc. (PEC's or Company) primary objective is to provide reliable and cost effective power to the 1.4 million households and businesses that depend on the Company. In planning to meet the needs of the growing region, the Company evaluates numerous factors. This is especially true given the significant uncertainties that exist today related to global climate policy, renewable energy, rising commodity costs, technology advancements and other aspects of the energy industry that are undergoing major change.

PEC's planning methodology is aimed at developing and implementing a robust plan that provides the greatest potential benefits in light of these and other uncertainties. The plan is also developed to ensure appropriate flexibility to address constraints, volatility, or other conditions that have a significant ability to influence the plan in the future.

The Integrated Resource Plan (IRP) shows the most robust plan is one that includes a mix of 1,000 megawatts of additional demand-side management (DSM) and energy efficiency (EE), renewable energy, purchased power, combustion-turbine generation, combined cycle generation, and nuclear generation. PEC advocates a balanced approach, which includes a strong commitment to DSM and EE, investments in renewables and emerging technologies, and state-of-the-art power plants and delivery systems. This approach helps ensure electricity remains available, reliable and affordable and is produced in an environmentally sound manner.

The plan developed through this IRP process and presented in this document is a balanced plan.

PEC's IRP is presented here as a comprehensive filing. Throughout the IRP document and in the appendices is a detailed discussion of the IRP process including the load and energy forecast, screening of supply-side technologies, renewables, DSM and EE plans as well as the methodology and development of the IRP.

Load and Energy Forecast

Methodology

Progress Energy Carolinas', Inc. forecasting processes have utilized econometric and statistical methods since the mid-70s. During this time, enhancements have been made to the methodology as data and software have become more available and accessible. Enhancements have also been undertaken over time to meet the changing data needs of internal and external customers.

The System Peak Load Forecast is developed from the System Energy Forecast using a load factor approach. This load forecast method couples the two forecasts directly, assuring consistency of assumptions and data. Class peak loads are developed from the class energy using individual class load factors. Peak loads for the residential, commercial, and industrial classes are then adjusted for projected load management impacts. The individual loads for the retail classes, wholesale customers, North Carolina Eastern Municipal Power Agency (NCEMPA), and Company use are then totaled and adjusted for losses between generation and the customer meter to determine System Peak Load.

Wholesale sales and demands include a portion that will be provided by the Southeastern Power Administration (SEPA). NCEMPA sales and demands include power which will be provided under the joint ownership agreement with them.

Summaries of the summer and winter Peak Load and Energy Forecast are provided in Tables 1 and 2. PEC's peak load forecasts assume the use of all load management capability at the time of system peak.

Assumptions

The filed forecast represents a retail demand growth rate of approximately 1.7% across the forecast period before subtracting for Demand-Side Management (DSM), which is almost equal to the customer growth rate of 1.8%. The retail demand growth rate drops to 1.0% after adjusting for DSM. Wholesale sales have become more uncertain due to the 1992 Energy Policy Act, subsequent FERC initiatives related to the wholesale market, the continuing evolution of the wholesale market, and market conditions. As expectations for the various wholesale contracts change, those expectations are appropriately reflected in the wholesale forecast.

Generally, growth in the standard of living as reflected in personal income and Gross Domestic Product (GDP) per capita is expected to slow modestly over the long term relative to historic levels. Real dollar prices are used to enhance model reliability during periods of varying inflation.

The forecast of system energy usage and peak load does not explicitly incorporate periodic expansions and contractions of business cycles, which are likely to occur from time to time during any long-range forecast period. While long-run economic trends exhibit considerable stability, short-run economic activity is subject to substantial variation. The exact nature, timing and magnitude of such short-term variations are unknown. The forecast, while it is a trended projection, nonetheless reflects the general long-run outcome of business cycles because actual historical data, which contain expansions and contractions, are used to develop the general relationships between economic activity and energy use. Weather normalized temperatures are assumed for the energy and system peak forecasts.

Customer Data

The tables below contain ten years of historical and 15 years of forecasted customer data.

	Annual Average Customers			
	Residential	Commercial	Industrial	Total
1998	988,466	172,883	4,826	1,166,175
1999	1,014,247	178,909	4,790	1,197,946
2000	1,040,549	183,486	4,739	1,228,773
2001	1,066,612	188,658	4,655	1,259,924
2002	1,091,229	193,301	4,511	1,289,040
2003	1,112,149	197,271	4,403	1,313,822
2004	1,133,669	202,981	4,310	1,340,960
2005	1,158,896	208,578	4,218	1,371,691
2006	1,184,071	213,354	4,138	1,401,563
2007	1,208,293	216,989	4,080	1,429,362
2008	1,228,793	219,535	4,000	1,452,328
2009	1,248,293	223,685	4,000	1,475,978
2010	1,269,793	226,693	4,000	1,500,486
2011	1,293,293	231,289	4,000	1,528,582
2012	1,318,793	235,520	4,000	1,558,313
2013	1,345,293	239,108	4,000	1,588,401
2014	1,371,293	242,757	4,000	1,618,050
2015	1,397,293	246,350	4,000	1,647,643
2016	1,423,293	249,928	4,000	1,677,221
2017	1,449,293	253,540	4,000	1,706,833
2018	1,476,293	257,218	4,000	1,737,511
2019	1,503,293	260,879	4,000	1,768,172
2020	1,530,793	264,670	4,000	1,799,463
2021	1,558,293	268,367	4,000	1,830,660
2022	1,585,793	272,211	4,000	1,862,004

	Retail Sales MWH		
	Residential	Commercial	Industrial
1998	13,207,005	10,644,572	14,978,075
1999	13,348,217	11,068,294	14,574,305
2000	14,090,936	11,432,314	14,445,641
2001	14,372,145	11,972,153	13,332,380
2002	15,238,554	12,467,562	13,088,615
2003	15,282,872	12,556,905	12,748,754
2004	16,003,184	13,018,688	13,036,419
2005	16,663,782	13,314,324	12,741,342
2006	16,258,675	13,358,042	12,415,862
2007	17,199,511	14,033,008	11,882,660
2008	17,347,625	14,317,780	11,857,110
2009	17,669,571	14,653,532	11,678,049
2010	18,004,235	14,863,015	11,627,345
2011	18,363,960	15,172,010	11,644,634
2012	18,664,678	15,448,525	11,664,652
2013	18,905,408	15,668,743	11,690,748
2014	19,132,013	15,891,954	11,718,500
2015	19,325,008	16,125,573	11,747,636
2016	19,661,026	16,360,895	11,771,052
2017	19,995,442	16,591,871	11,794,608
2018	20,341,952	16,836,883	11,818,034
2019	20,697,764	17,098,097	11,841,341
2020	21,067,116	17,378,498	11,865,075
2021	21,438,640	17,658,432	11,888,790
2022	21,815,170	17,969,922	11,912,638

Screening of Generation Alternatives

Methodology

PEC periodically assesses various generating technologies to ensure that projections for new resource additions capture new and emerging technologies over the planning horizon. This analysis involves a preliminary screening of the generation resource alternatives based on commercial availability, technical feasibility, and cost.

First, the commercial availability of each technology is examined for use in utility-scale applications. For a particular technology to be considered commercially available, the technology must be able to be built and operated on an appropriate commercial scale in continuous service by or for an electric utility.

Second, technical feasibility for commercially available technologies was considered to determine if the technology meets PEC's particular generation requirements and whether it would integrate well into the PEC system. The evaluation of technical feasibility included the size, fuel type, and construction requirements of the particular technology and the ability to match the technology to the service it would be required to perform on the PEC's system (e.g., baseload, intermediate, or peaking).

Finally, for each alternative, an estimate of the levelized cost of energy production, or "busbar" cost, was developed. Busbar analysis allows for the long-term economic comparison of capital, fuel, and O&M costs over the typical life expectancy of a future unit at varying capacity factor levels. For the screening of alternatives, the data are generic in nature and thus not site specific. Cost and performance projections were based on EIA's 2008 Annual Energy Outlook report and on internal PEC resources.

The generic capital and operating costs reflect the impact of known and emerging environmental requirements to the extent that such requirements can be quantified at this time. As these requirements and their impacts are more clearly defined in the future, capital and operating costs are subject to change. Such changes could alter the relative cost of one technology versus another and therefore result in the selection of different generating technologies for the future.

Cost and Performance

Categories of capacity alternatives that were reviewed as potential resource options included Conventional, Demonstrated, and Emerging technologies. *Conventional* technologies are mature, commercially available options with significant acceptance and operating experience in the utility industry. *Demonstrated* technologies are those with limited commercial operating experience and/or are not in widespread use. *Emerging* technologies are still in the concept, pilot, or demonstration stage or have not been used in the electric utility industry. In the most recent assessment, the following generation technologies were screened:

<u>Conventional Technologies</u>
Combined Cycle (CC)
Combustion Turbine (CT)
Hydro
Pulverized Coal (PC)

Demonstrated Technologies
Biomass
Integrated (Coal) Gasification/Combined Cycle (IGCC)
Nuclear Advanced Light Water Reactor (ALWR)
Municipal Solid Waste-Landfill Gas (MSW-LFG)
Wind

Emerging Technologies
Fuel Cell (FC)
Solar Photovoltaic (PV)

Of the technologies evaluated, not all are proven, mature, or commercially available. This is important to keep in mind when reviewing the data, as some options shown as low cost may *not* be commercially available or technically feasible as an option to meet resource plan needs and requirements at this time. In addition, the less mature a technology is the more uncertain and less accurate its cost estimate may be.

For example, fuel cells, which are currently still in the pilot or demonstration stage, can be assembled building-block style to produce varying quantities of electric generation. However, as currently designed, a sufficient number of fuel cells cannot be practically assembled to create a source of generation comparable to other existing bulk generation technologies, such as combined cycle (CC). Further development of this technology is needed before it becomes viable as a resource option.

Integrated Gasification-Combined Cycle (IGCC) appears to offer the potential to be competitive with other baseload generation technologies and has fewer environmental concerns. This technology, though, has only been demonstrated at a handful of installations and is just now becoming commercially available. With the possible need for new baseload generation in the future, PEC will continue to monitor the progress of this technology.

Hydro generation has been a valuable and significant part of the generating fleet for the Carolinas. The potential for additional hydro generation on a commercially viable scale is limited and the cost and feasibility is highly site specific. Given these constraints, hydro was not included in the more detailed evaluations but may be considered when site opportunities are evidenced and the potential is identified. PEC will continue to evaluate hydro opportunities on a case-by-case basis and will include it as a resource option if appropriate.

Wind projects have high fixed costs but low operating costs. Therefore, at high enough capacity factors they could become economically competitive with the conventional technologies identified. However, geographic and atmospheric characteristics affect the ability of wind projects to achieve those capacity factors. Wind projects must be constructed in areas with high average wind speed. In general, wind resources in the Carolinas are concentrated in two regions. The first is along the Atlantic coast and barrier islands. The second area is the higher ridge crests in the western portions of the states. Because wind is not dispatchable and provides little or no capacity value, it may not be suited to provide consistent capacity at the time of the system peak. Offshore wind power, an emerging technology, may provide greater potential for the Carolinas in the future. The Carolinas benefit from offshore wind and shallow water that is less than 30 meters deep within 50 nautical miles of shore. Once the technology is developed and the regulatory process is established, this untapped energy source may contribute capacity and

energy production for the PEC system. PEC will continue to monitor the progress and the cost effectiveness of this technology.

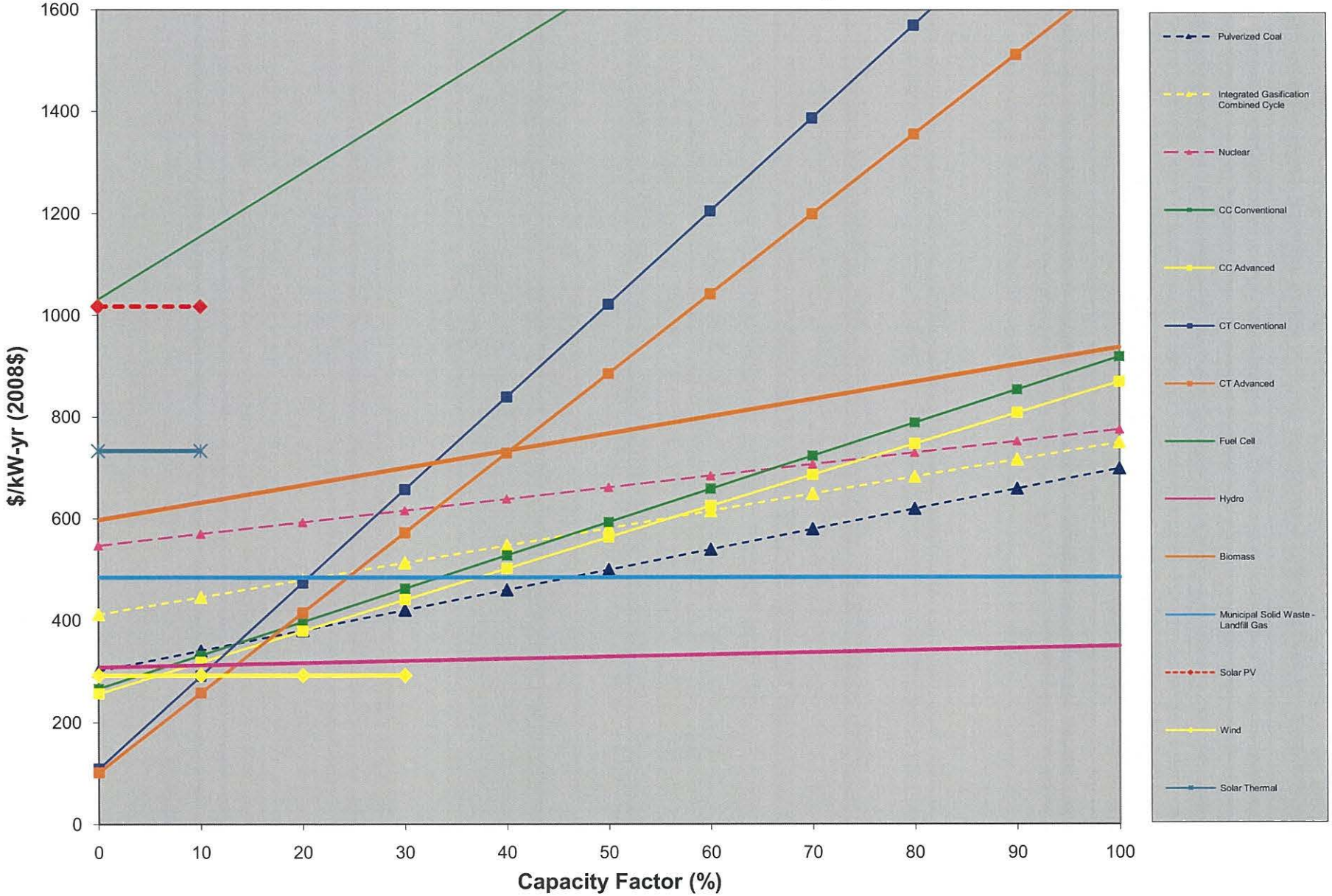
Solar photovoltaic (PV) projects are technically constrained from achieving high capacity factors. In the southeast, they would be expected to operate at a capacity factor of approximately 20%, making them unsuitable for intermediate or baseload duty cycles. At the lower capacity factors, they, like wind, are not dispatchable and therefore less suited to provide consistent peaking capacity. Aside from their technical limitations, PV projects are not currently economically competitive generation technologies. With the passage of North Carolina Senate Bill 3 and the premiums provided by the NC GreenPower program, solar photovoltaic installations are increasing in number and scale. Existing solar providers generally sell the entire output of the system to PEC at avoided cost rates to be eligible for NC GreenPower incentives. PEC now has over fifty solar contracts that contribute approximately 2.11 MW; all of it is non-firm power.

The capacity value of wind and solar resources depends heavily on the correlation between the system load profile, wind speed, and solar insolation. A recent Utility Wind Integration Group report noted that the capacity value of wind is typically less than 40% of nameplate capacity. Although wind and solar projects are currently not viable options for meeting *reserve* requirements due to their relatively high cost and uncertain operating characteristics, they will play an increasing role in PEC's *energy* portfolio through PEC's renewable compliance program, which is detailed below and in Appendix D. Geothermal has not been evaluated as it is not reasonably available in the Carolinas. External economic and non-economic forces, such as tax incentives, environmental regulations, federal or state policy directives, technological breakthroughs, and consumer preferences through "green rates", also drive these types of technologies. As part of PEC's regular planning cycle, changes to these external conditions are considered, as well as any technological changes, and will be continually evaluated for suitability as part of the overall resource plan.

PEC's IRP includes purchased power from renewables such as solar, biomass, and municipal solid waste-landfill gas (MSW-LFG) facilities. The IRP Tables 1 and 2 detail the current and undesignated renewable capacity. PEC is actively engaged in a variety of projects to develop new alternative sources of energy, including solar, storage, biomass, and landfill gas technologies. Renewables will consistently be evaluated for their ability to meet renewable energy requirements and resource planning needs on a case-by-case basis and included as a resource as appropriate. Further detail regarding renewables is given in the Renewable Energy Requirements section below and in Appendix D.

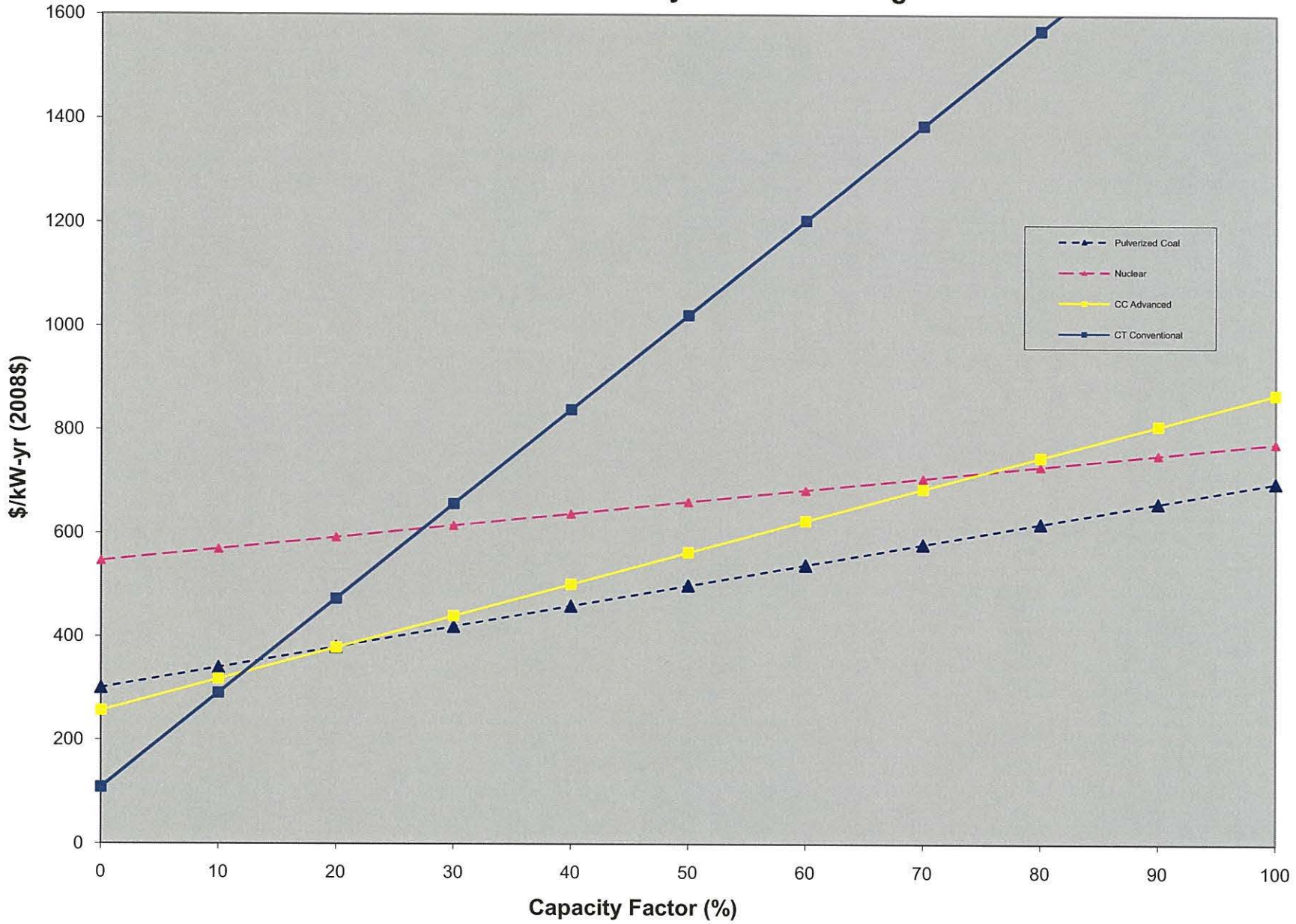
Figure 1 provides an economic comparison of all technologies examined based on generic capital, operating, and fuel cost projections. Figure 2 shows the most economical and viable utility scale technologies. For the most economic utility scale supply-side technologies in Figure 2, more detailed economic and site specific information was developed for inclusion in the resource plan evaluation process (see Resource Plan Evaluation and Development section below) These technologies include simple-cycle combustion turbine, combined cycle, pulverized coal, and nuclear.

Figure 1
Levelized Busbar Cost for All Technologies



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission or other site specific criteria.

Figure 2
Levelized Busbar Cost for Utility Scale Technologies



NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission or other site specific criteria.

Renewable Energy Requirements

In 2007, NC Senate Bill 3 was signed into law, establishing a renewable energy and energy efficiency portfolio standard (REPS). In accordance with the bill, the state's electric companies must gradually increase their use of renewable energy. The utilities, in general, must purchase or generate 3 percent of their energy (based on the prior year's total retail sales) from renewable resources by 2012. The public utilities – PEC, Duke Energy Carolinas, and Dominion North Carolina Power – must increase their use of renewable energy to 12.5 percent in 2021 according to the schedule below.

REPS Requirement

Calendar Year	% Requirement
2012	3% of 2011 NC retail sales
2015	6% of 2014 NC retail sales
2018	10% of 2017 NC retail sales
2021 and thereafter	12.5% of 2020 NC retail sales

The utilities are allowed to meet a portion of the renewable requirement through energy efficiency. Through 2020, up to 25% of the REPS requirement may be met with energy efficiency; after 2020, up to 40% of the REPS requirement may be met with energy efficiency. The standard may also be met through the purchase of renewable energy certificates (RECs).

A portion of the renewable standard must be met with solar power and with power generated by swine and poultry waste. The swine and poultry waste requirements are requirements for the state of NC, in aggregate.

Requirement for Solar Energy Resources

Calendar Year	% of NC Retail Sales
2010	0.02%
2012	0.07%
2015	0.14%
2018	0.20%

Requirement for Swine Waste Resources

Calendar Year	% of NC Retail Sales
2012	0.07%
2015	0.14%
2018	0.20%

Requirement for Poultry Waste Resources

Calendar Year	Energy Required
2012	170,000 MWh
2013	700,000 MWh
2014 and thereafter	900,000 MWh

Exactly how the requirements of the REPS will be achieved, and through which technologies, is not fully known at this time. In order to prepare for compliance with the new REPS

requirements, PEC issued a Request for Proposals for Renewable Power Supply Resources on November 2, 2007. As of June 30th, 2008, a total of forty-eight bids were received from solar, biomass, wind, and hydro resources. None of the bids received through the renewable RFP were determined to be cost effective as part of the normal resource planning analysis. The renewable bids received were then primarily evaluated on how each project fit within the near-term and long-term REPS compliance plan, which is contained herein as Appendix D. The IRP Tables 1 and 2 reflect both committed renewables and undesignated renewables given the exact makeup of the compliance is unknown at this time.

Demand Side Management and Energy Efficiency Program Plan

PEC is committed to making sure electricity remains available, reliable and affordable and that it is produced in an environmentally sound manner and, therefore, advocates a balanced solution to meeting future energy needs in the Carolinas. That balance includes a strong commitment to DSM and EE as well as investments in renewable and emerging energy technologies and state-of-the art power plants and delivery systems. In May 2007, PEC announced an aggressive goal of doubling the amount of peak load reduction capability available through DSM and EE programs, currently about 1,000 megawatts (MW). This plan has the potential to displace the need for 1,140 MW of new generation over the next ten-years.

To meet this goal PEC is developing new DSM and EE programs and evaluating their effectiveness and potential participation rates to determine their viability in further reducing electricity demand. PEC's DSM and EE plan will be flexible, and programs will be evaluated on an ongoing basis so that program refinements and budget adjustments can be made in a timely fashion to maximize benefits and cost effectiveness. Initiatives will be aimed at helping all customer classes and market segments use energy more wisely.

PEC is also evaluating programs and delivery models that have proven successful in the past. PEC will also be evaluating new technologies and new delivery options on an ongoing basis to ensure that we are delivering comprehensive programs in the most cost effective way. PEC will select and seek Commission approval to implement DSM and EE programs that are cost effective and consistent with PEC's forecasted resource needs over the planning horizon. To accomplish this, PEC has commissioned a DSM and EE potential assessment study. This study will identify the universe of programs and measures available to meet PEC's resource needs. In order to determine cost effectiveness, PEC intends to use the Rate Impact Measure test to evaluate DSM programs. With regard to energy efficiency programs, PEC will primarily rely upon the Total Resource Cost Test and the Utility Cost Test. Provided however, PEC will consider the results of the Rate Impact Measure test in determining whether implementation of the measure or program is in the best interest of PEC's overall customer body. Currently PEC has submitted five DSM and EE programs to the North Carolina Utilities Commission for approval (see Appendix E).

To support the aggressive goal, PEC also implemented a strategic consumer education campaign, "Save The Watts," which includes a dynamic website as well as print and broadcast media. The outreach campaign provides a wide array of efficiency tips to match varying lifestyles and directly links consumers to PEC's energy efficiency program offerings at www.savethewatts.com.

These investments and this educational campaign are focused on building customer awareness about energy efficiency and, ultimately, changing consumer energy behaviors and reducing energy resource needs by driving large-scale, long-term participation in efficiency programs. To support this effort, PEC has significantly expanded its DSM and EE organization, whose focus will be to plan and implement programs that work well with customer lifestyles, expectations and business needs. Significant and sustained customer participation is critical to achieving and surpassing the aggressive DSM goals shared by PEC and its customers.

Finally, PEC is setting a conservation example by converting its own buildings and plants, as well as distribution and transmission systems, to new technologies that increase operational efficiency. For further detail on PEC's DSM and EE programs see Appendix E.

Reserve Criteria

The reliability of energy service is a primary input in the development of the resource plan. Utilities require a margin of generating capacity reserve to be available to the system in order to provide reliable service. Periodic scheduled outages are required to perform maintenance, inspections of generating plant equipment, and to refuel nuclear plants. Unanticipated mechanical failures may occur at any given time, which may require shutdown of equipment to repair failed components. Adequate reserve capacity must be available to accommodate these unplanned outages and to compensate for higher than projected peak demand due to forecast uncertainty and weather extremes. In addition, some capacity must also be available as operating reserve to maintain the balance between supply and demand on a real-time basis.

The amount of generating reserve needed to maintain a reliable power supply is a function of the unique characteristics of a utility system including load shape, unit sizes, capacity mix, fuel supply, maintenance scheduling, unit availabilities, and the strength of the transmission interconnections with other utilities. There is no one standard measure of reliability that is appropriate for all systems since these characteristics are particular to each individual utility.

Methodology

PEC employs both deterministic and probabilistic reliability criteria in its resource planning process. The Company establishes a reserve criterion for planning purposes based on probabilistic assessments of generation reliability, industry practice, historical operating experience, and judgment.

PEC conducts multi-area probabilistic analyses to assess generation system reliability in order to capture the random nature of system behavior and to incorporate the capacity assistance available through interconnections with other utilities. Decision analysis techniques are also incorporated in the analysis to capture the uncertainty in system demand. Generation reliability depends on the strength of the interconnections, the generation reserves available from neighboring systems, and the diversity in loads throughout the interconnected area. Thus, the interconnected system analysis shows the overall level of generation reliability and reflects the expected risk of capacity deficient conditions for supplying load.

A Loss-of-Load Expectation (LOLE) of one day in 10 years continues to be a widely accepted criterion for establishing system reliability. PEC uses a target reliability of one day in ten years LOLE for generation reliability assessments. LOLE can be viewed as the expected number of

days that load will exceed available capacity. Thus, LOLE indicates the number of days that a capacity deficient condition would occur, resulting in the inability to supply some portion of customer demand. Results of the probabilistic assessments are correlated to appropriate deterministic measures of reliability, such as capacity margin or reserve margin, for use as targets in developing the resource plan.

Adequacy of Projected Reserves

Reliability assessments have shown that reserves projected in PEC's resource plan are appropriate for providing an adequate and reliable power supply. The Company's resource plan reflects capacity margins in the range of approximately 11% to 20%, corresponding to reserve margins of approximately 13% to 26%. It should be noted that actual reserves as measured by megawatts of installed capacity continue to increase as the load and the size of the system increase.

The reliability of PEC's generating system has improved since the mid-nineties. The addition of smaller and highly reliable CT capacity increments to the Company's resource mix improve the reliability and flexibility of the PEC fleet in responding to increased load requirements. Since 1996, PEC has added approximately 3,300 MW of new combustion turbine and combined cycle capacity to system resources, either through new construction or purchased power contracts. Shorter construction lead times for building new combustion turbine and combined cycle power plants, as contrasted to baseload plants, allow greater flexibility to respond to changes in capacity needs and thus reduce exposure to load uncertainty. The Company's resource plan includes approximately 157 MW of additional CT capacity in 2009 and 600 MW of additional CC capacity in 2011. All of these factors help to ensure the Company's ability to provide an adequate and reliable power supply.

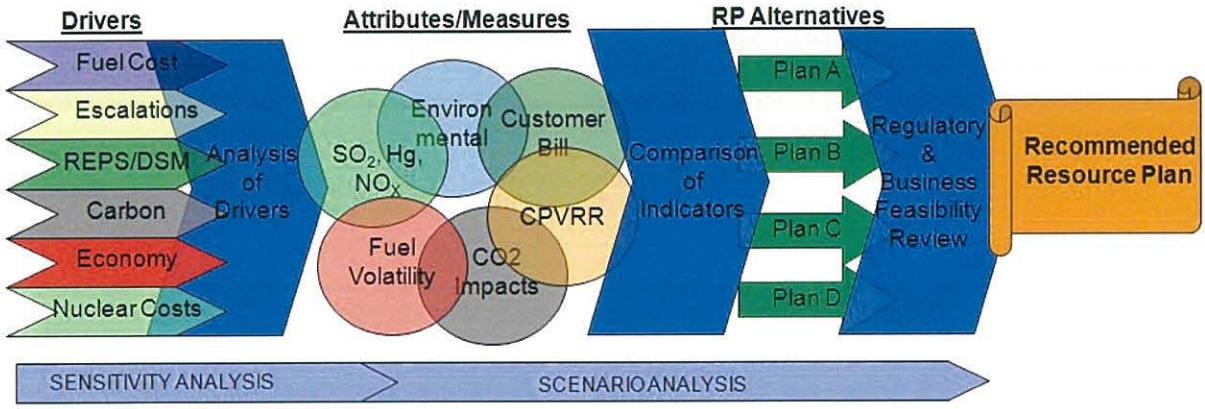
Resource Plan Evaluation and Development

Methodology

The objective of the resource planning process is to create a robust plan. While the type of analysis illustrated in Figures 1 and 2 above provide a valuable tool for a comparative screening of technologies, i.e. a comparison of technologies of like operating characteristics, peaking vs. peaking, baseload vs. baseload, etc., it does not address the specific needs of any particular resource plan. Additionally, site-specific requirements, such as transmission, pipeline costs, and fuel availability, must be considered when conducting resource optimization analyses. A robust plan is one that provides the greatest potential benefits given the uncertainties, constraints, and volatility of key drivers that are currently affecting the plan or have a significant probability of influencing the plan in the future. In order to complete this objective, the resource planning process is comprised of a two phase extensive process that takes into consideration numerous factors, both current and future, related to issues such as customer costs, fuel costs, renewables, environmental requirements and unknowns, demand-side management, energy efficiency, potential technology shifts, load and energy changes, and capital costs of new central station facilities. The resource planning process incorporates the impact of all demand-side management programs on system peak load and total energy consumption, and optimizes supply-side options into an integrated plan that will provide reliable and cost-effective electric service to PEC's customers.

The two phase resource planning process is comprised of a sensitivity analysis phase and a scenario analysis phase. Below is a brief overview of the resource planning process. Appendix A discusses the process to develop the robust resource plan in detail. The resource planning process can be seen in a simplistic format in Figure 3 below.

Figure 3 Integrated Resource Planning Process Flowchart



The sensitivity analysis is based on the expertise of numerous individuals throughout PEC's organization that provide input and knowledge relative to the key drivers that are, or may be, influencing the plan. These key drivers are then utilized to stress the models to determine which of the drivers are "movers" and which are "shakers." It is important to understand the difference between a mover and shaker. In general, a mover has less impact on the resource plan and can be adapted to more easily; whereas, a shaker has a more significant impact on the resource plan and may require new directions to be taken. This mover/shaker analysis results in the development of potential alternative plans that can then be utilized in the scenario analysis.

The scenario analysis contemplates and develops future states that bound the potential outcomes of the key drivers such as load, energy, escalations, nuclear capital costs, fuel costs, and carbon costs. The alternative plans that are developed in the sensitivity analysis are then tested in each scenario. By testing each of these alternative plans in each of the scenarios, it can be determined how each of the plans fare in each scenario and in aggregate to all scenarios. The ranking of each plan in each scenario is performed using key attributes in the categories of customer cost and environmental. In short, the scenario analysis develops bounding future potential states and subjects the alternative plans to the future states such that they can be ranked relative to each other based on key attributes in the customer cost and environmental categories.

As mentioned previously a robust plan minimizes the adverse impacts of unforeseen changes, and produces acceptable results for a broad range of events. This is why different scenarios of load, energy, fuel, construction cost escalation, environmental, technology shifts and other factors were taken into consideration when testing the plans to determine robustness. Another important benefit of such broad scenario analysis is that the integrity of the plan is maintained even with moderate changes in inputs used in the analysis, such as load.

The results of the resource planning process detailed in Appendix A, demonstrate that a plan which includes 1000 MW of additional DSM and EE, renewables, purchased power, combustion turbine generation, combined cycle generation, and nuclear generation, accomplishes the objective of a robust resource plan. Thus, it is the basis of the preferred resource plan shown in

Tables 1 and 2 below. Meeting the anticipated growth and resulting demand for electricity within PEC's service territory requires a balanced approach, including a strong commitment to demand side management, investments in emerging alternatives and renewable energy technologies, and investments in state-of-the-art power plants.

Progress Energy - Carolinas

Table 1 2008 Annual IRP (Summer)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
GENERATION CHANGES															
Sited Additions	157		600												
Undesignated Additions (1)					126			169			1,085	1,085			
Planned Project Uprates	21	20		5											
Pollution Control Derates	(29)				(3)	(1)									
INSTALLED GENERATION															
Nuclear	3,495	3,515	3,515	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520
Fossil	5,176	5,176	5,176	5,176	5,173	5,172	5,172	5,172	5,172	5,172	5,172	5,172	5,172	5,172	5,172
Combined Cycle	536	536	1,136	1,136	1,136	1,136	1,136	1,136	1,136	1,136	1,136	1,136	1,136	1,136	1,136
Combustion Turbine	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135
Hydro	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Undesignated (1)					126	126	126	295	295	295	1,380	2,465	2,465	2,465	2,465
TOTAL INSTALLED *	**12,567**	**12,587**	**13,187**	**13,192**	**13,315**	**13,314**	**13,314**	**13,483**	**13,483**	**13,483**	**14,568**	**15,653**	**15,653**	**15,653**	**15,653**
PURCHASES & OTHER RESOURCES **															
SEPA	95	95	95	95	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen	179	179	179	179	179	179	179	179	179	179	179	179	179	179	179
Renewables	28	25	25	25	25	25									
Renewables Undesignated				44	44	44	98	98	98	102	102	102	103	103	103
NUG QF - Other	9														
AEP/Rockport 2	250														
Broad River CT	808	808	808	808	808	808	808	808	808	808	808	808	808	808	808
Southern CC Purchase - ST		150	150												
Southern CC Purchase - LT		150	150	150	150	150	150	150	150	150	150	150	150	150	150
Undesignated Purchase				100					100	200					
TOTAL SUPPLY RESOURCES	**13,936**	**13,994**	**14,594**	**14,592**	**14,630**	**14,628**	**14,657**	**14,827**	**14,927**	**15,030**	**15,916**	**17,001**	**17,001**	**17,001**	**17,001**
SYSTEM PEAK LOAD	**12,621**	**12,772**	**13,005**	**13,313**	**13,474**	**13,726**	**13,932**	**14,137**	**14,337**	**14,522**	**14,728**	**14,943**	**15,203**	**15,412**	**15,622**
Firm Sales	200	200	200	100	100	100	100	100	100	100	100	100	100	100	100
Energy Efficiency & Demand Response	441	566	705	854	954	1,062	1,164	1,258	1,342	1,414	1,466	1,501	1,538	1,563	1,584
System Firm Load after DSM	**12,380**	**12,406**	**12,500**	**12,559**	**12,620**	**12,764**	**12,868**	**12,979**	**13,095**	**13,208**	**13,362**	**13,542**	**13,765**	**13,949**	**14,138**
RESERVES (2)	**1,556**	**1,588**	**2,094**	**2,033**	**2,010**	**1,864**	**1,789**	**1,848**	**1,832**	**1,822**	**2,554**	**3,459**	**3,236**	**3,052**	**2,863**
Capacity Margin (3)	11%	11%	14%	14%	14%	13%	12%	12%	12%	12%	16%	20%	19%	18%	17%
Reserve Margin (4)	13%	13%	17%	16%	16%	15%	14%	14%	14%	14%	19%	26%	24%	22%	20%
ANNUAL SYSTEM ENERGY (GWh)	**66,442**	**67,182**	**68,280**	**69,422**	**69,462**	**70,345**	**71,147**	**72,102**	**73,018**	**73,901**	**74,897**	**75,982**	**77,141**	**78,216**	**79,297**

Notes:

* TOTAL INSTALLED includes Mod-24 unit rating changes.

** Purchases are assumed to be renewed unless information available indicates otherwise. Undesignated renewables are projections.

Footnotes:

(1) Undesignated capacity may be replaced by purchases, uprates, DSM; or a combination thereof. Joint ownership opportunities will be evaluated with baseload additions.

(2) Reserves = Total Supply Resources - Firm Obligations

(3) Capacity Margin = Reserves / Total Supply Resources * 100.

(4) Reserve Margin = Reserves / Firm Obligations * 100.

Progress Energy - Carolinas

Table 2 2008 Annual IRP (Winter)

	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
GENERATION CHANGES															
Sited Additions		195		664											
Undesignated Additions (1)					147				201			1,125	1,125		
Planned Project Uprates	11	10	20	5											
Pollution Control Derates	(24)	(22)			(3)	(1)									
INSTALLED GENERATION															
Nuclear	3,622	3,632	3,652	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657	3,657
Fossil	5,332	5,310	5,310	5,310	5,307	5,305	5,305	5,305	5,305	5,305	5,305	5,305	5,305	5,305	5,305
Combined Cycle	617	617	617	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281
Combustion Turbine	3,511	3,706	3,706	3,706	3,706	3,706	3,706	3,706	3,706	3,706	3,706	3,706	3,706	3,706	3,706
Hydro	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Undesignated (1)					147	147	147	147	348	348	348	1,473	2,598	2,598	2,598
TOTAL INSTALLED *	**13,310**	**13,493**	**13,513**	**14,182**	**14,326**	**14,324**	**14,324**	**14,324**	**14,525**	**14,525**	**14,525**	**15,650**	**16,775**	**16,775**	**16,775**
PURCHASES & OTHER RESOURCES **															
SEPA	95	95	95	95	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen	179	179	179	179	179	179	179	179	179	179	179	179	179	179	179
Renewables	28	25	25	25	25	25									
Renewables Undesignated				44	44	44	98	98	98	102	102	102	103	103	103
NUG QF - Other	9														
AEP/Rockport 2	250														
Broad River CT	836	836	836	836	836	836	836	836	836	836	836	836	836	836	836
Southern CC Purchase - ST		150	150												
Southern CC Purchase - LT		150	150	150	150	150	150	150	150	150	150	150	150	150	150
Undesignated Purchase				100											
TOTAL SUPPLY RESOURCES	**14,707**	**14,927**	**14,947**	**15,610**	**15,669**	**15,667**	**15,696**	**15,696**	**15,898**	**15,901**	**15,902**	**17,027**	**18,152**	**18,152**	**18,152**
SYSTEM PEAK LOAD	**11,358**	**11,483**	**11,688**	**11,959**	**12,091**	**12,308**	**12,487**	**12,663**	**12,837**	**12,998**	**13,180**	**13,371**	**13,602**	**13,790**	**13,952**
Firm Sales	200	200	200	100	100	100	100	100	100	100	100	100	100	100	100
Energy Efficiency & Demand Response	519	554	652	756	867	918	967	1,012	1,062	1,110	1,150	1,185	1,214	1,245	1,270
System Firm Load after DSM	**11,039**	**11,129**	**11,236**	**11,303**	**11,324**	**11,490**	**11,620**	**11,751**	**11,875**	**11,988**	**12,130**	**12,286**	**12,488**	**12,645**	**12,782**
RESERVES (2)	**3,668**	**3,798**	**3,711**	**4,307**	**4,345**	**4,177**	**4,076**	**3,945**	**4,023**	**3,913**	**3,772**	**4,741**	**5,664**	**5,507**	**5,370**
Capacity Margin (3)	25%	25%	25%	28%	28%	27%	26%	25%	25%	25%	24%	28%	31%	30%	30%
Reserve Margin (4)	33%	34%	33%	38%	38%	36%	35%	34%	34%	33%	31%	39%	45%	44%	42%

Notes:

* TOTAL INSTALLED includes Mod-24 unit rating changes.

** Purchases are assumed to be renewed unless information available indicates otherwise. Undesignated renewables are projections.

Footnotes:

(1) Undesignated capacity may be replaced by purchases, uprates, DSM; or a combination thereof. Joint ownership opportunities will be evaluated with baseload additions.
(2) Reserves = Total Supply Resources - Firm Obligations
(3) Capacity Margin = Reserves / Total Supply Resources * 100.
(4) Reserve Margin = Reserves / Firm Obligations * 100.

IRP Tables and Plan Discussion

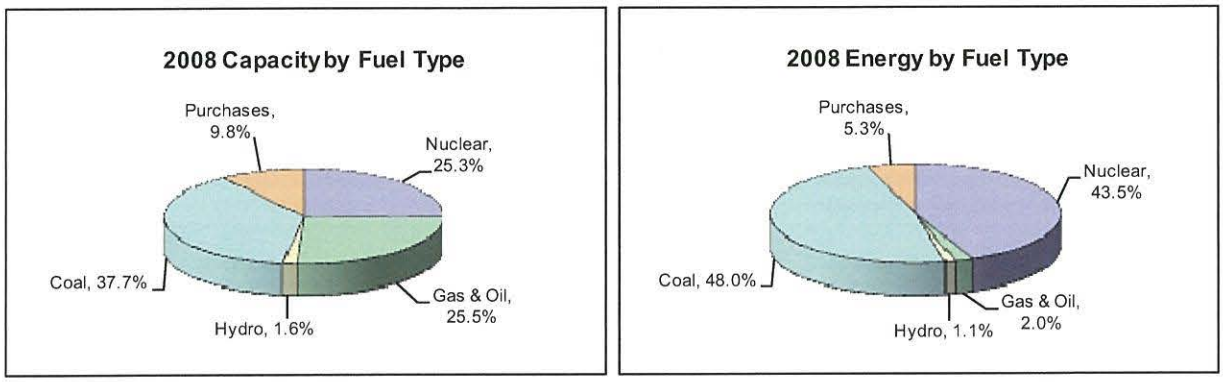
PEC's 2008 Annual IRP as presented in Tables 1 and 2 includes the 1000 MW of additional DSM and EE as well as significant additional renewables (see renewables and DSM appendices for further detail). PEC is actively pursuing expansion of its demand-side management and renewables programs as one of the most effective ways to offset the need for new power plants and protect the environment. In the coming years, PEC will continue to invest in renewables, DSM, EE and state-of-the art power plants and will evaluate the best available options for building new baseload, including advanced design nuclear and clean coal technologies. If PEC proceeds with a new nuclear plant, it would not be online until 2018 or later. At this time, though, no definitive decision has been made to construct new baseload plants.

In the near term, the current resource plan utilizes gas-fired generators for intermediate needs and peaking needs when possible, and oil-fired units for peaking needs when necessary. Gas-fired units are the most environmentally benign, economical, large-scale capacity additions available for meeting peaking and intermediate loads. New designs of these technologies are more efficient (as measured by heat rate) than previous designs, resulting in a smaller impact on the environment. PEC is also seeking license renewal options for our existing hydro and nuclear plants. A combustion turbine at PEC's Wayne County Facility is under construction with an in-service date of June 1, 2009. In addition, a Certificate of Public Convenience and Necessity has been filed for a combined cycle at PEC's Richmond County Facility with an in-service date of June 1, 2011 (see Short Term Action Plan in Appendix H).

Capacity and Energy

Figure 4 below shows PEC's capacity (MW) and energy (MWh) by fuel type projected for 2008. Nuclear and coal generation currently make-up approximately 63% of total capacity resources, yet account for about 92% of total energy requirements. Gas and oil generation accounts for about 26% of total supply capacity, yet about 2% of total energy, the balance is from hydro and purchased power.

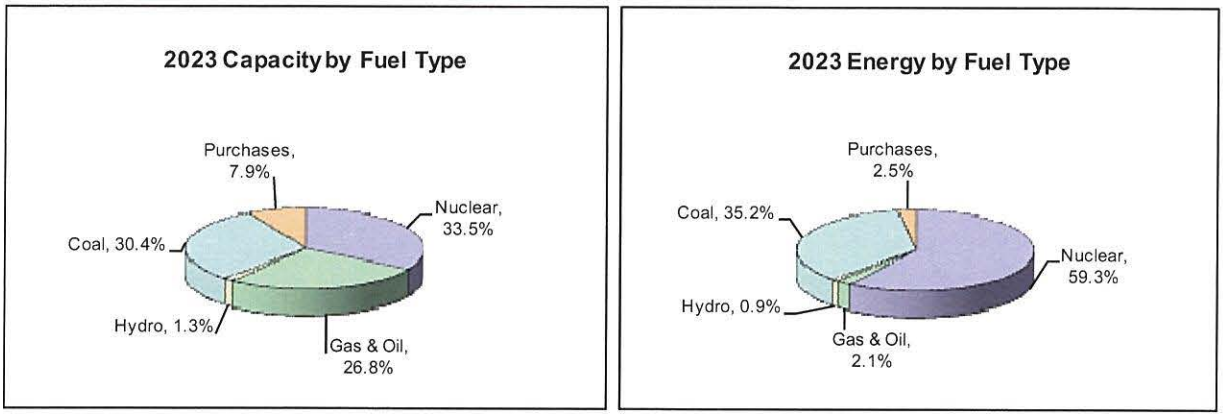
Figure 4



The Company's resource plan includes additions fueled by natural gas and oil, as well as possible new baseload generation. The Company's capacity and energy by fuel type projected for 2023 are shown in Figure 5. Gas and oil resources are projected to increase to about 27% of total supply capacity, while only serving about 2% of the total energy requirements. In 2023, nuclear and coal are projected to account for approximately 64% of total capacity resources and serve

about 94% of total system energy requirements. These figures demonstrate that nuclear and coal resources will continue to account for the largest share of system capacity (MW) and satisfy most of the system energy (MWh) requirements through the planning horizon.

Figure 5



Based on PEC's forecasted load and resources in the current resource plan, LOLE is expected to be within the reliability target of one day in ten years. The resources in the current plan, including reserves, are expected to continue to provide a reliable power supply.

Load Duration Curves

Figures 6 through 9 below are load duration curves for 2008 and 2023. The load duration curves detail the need relative to hours of the year, which is shown as a percentage. Figure 6 shows a curve without the existing DSM but it does not show existing EE as it is embedded in the forecast at this point. Both figures have insets (Figures 8 & 9) that show the reduction of peak load due to DSM which reduces the need for additional peaking generation. By comparing the 2008 and 2023 curves it is also possible to see the growth that is expected. The base demand even after DSM and EE increases by approximately 1,500 MW between 2008 and 2023.

Figure 6

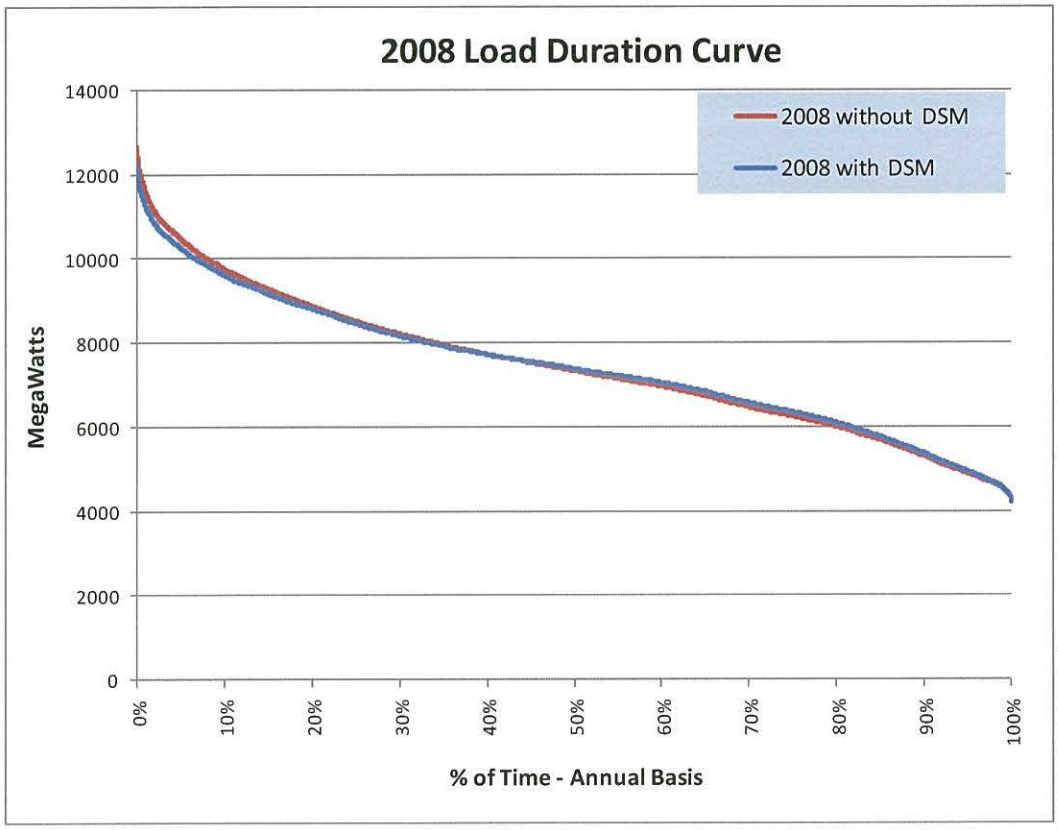


Figure 7

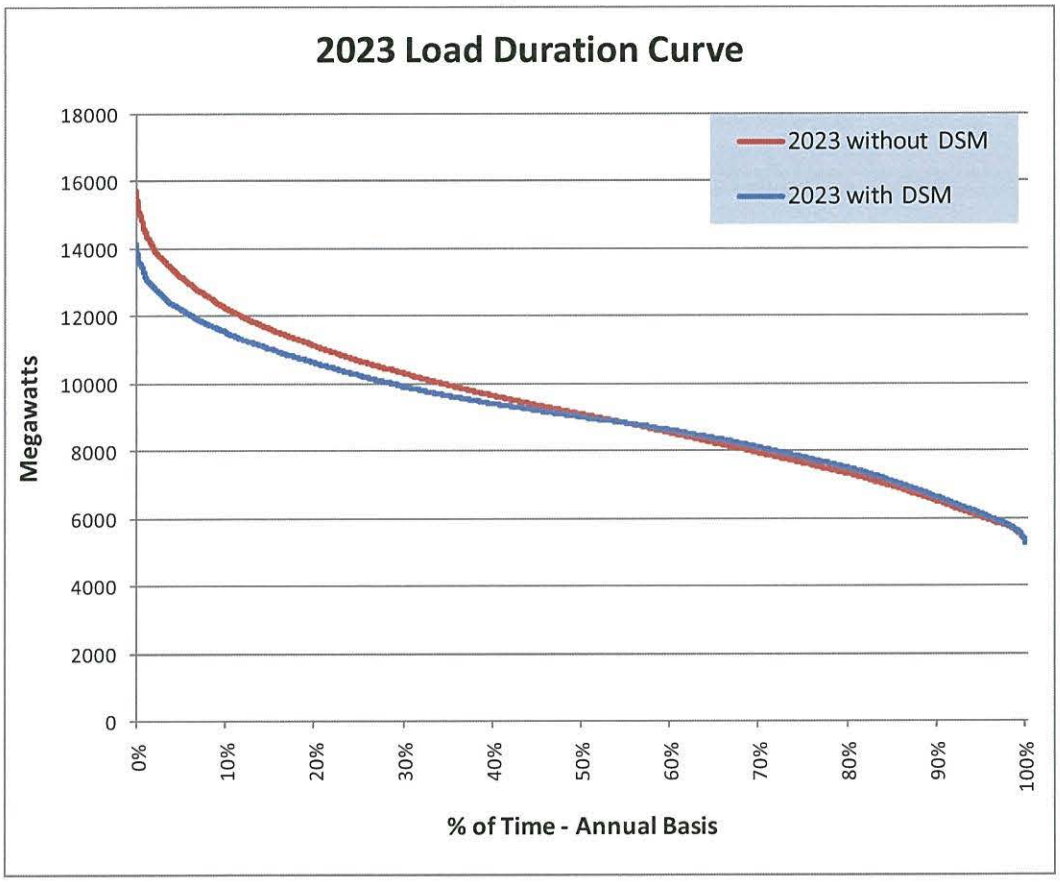


Figure 8

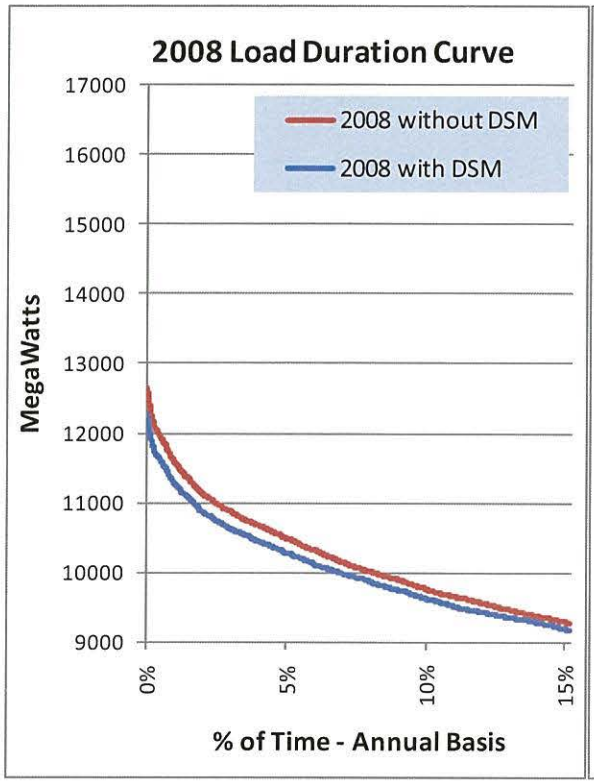
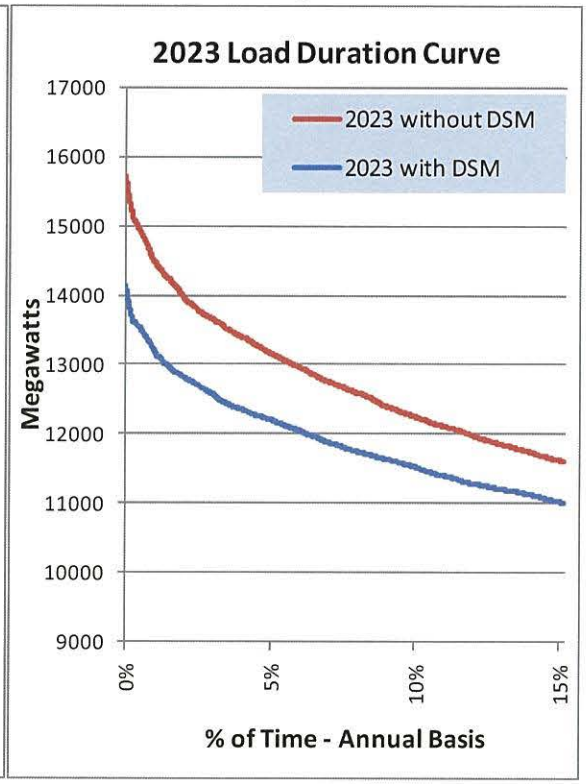


Figure 9



Summary

PEC is an advocate of the balanced approach for satisfying future power supply needs, which includes a strong commitment to DSM and EE, investments in renewables and emerging technologies, and state-of-the art power plants and delivery systems. This approach ensures electricity remains available, reliable, and affordable and is produced in an environmentally sound manner. The plan presented and developed through the resource planning process and presented in this IRP document is not only balanced but robust. It provides the greatest potential benefits given the uncertainties, constraints, and volatility of key drivers that are currently affecting the plan or have a significant ability to influence the plan in the future.

It can be seen that the most robust plan, the IRP, is one that includes DSM and EE, renewables, purchased power, combustion turbine generation, combined cycle generation, and nuclear generation. Though uncertainties will continue to change and evolve, this process and its results provide the necessary guidance to proceed. This is why PEC evaluates and explores the potential impacts of global climate policies, environmental regulation, technology shifts, and more in its process and PEC continues to invest in and explore emerging technologies, renewables, DSM and EE, and state-of-the art generating plants. Only through this integrated effort will PEC be able to provide electricity in a reliable, affordable, and environmentally sound manner.

Progress Energy

Progress Energy Carolinas Integrated Resource Plan

Appendix A
Evaluation of Resource Options

September 1, 2008

Resource Planning Analytics and Evaluations for Plan Development

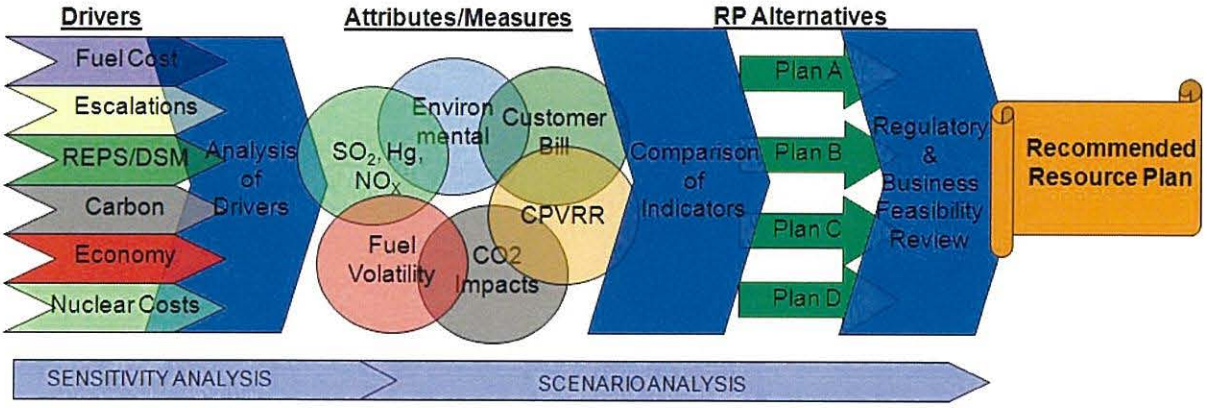
The objective of the resource planning process is to create a robust plan. A robust plan is one that provides the greatest potential benefits given the uncertainties, constraints, and volatility of key drivers that are currently affecting the plan or have a significant probability of influencing the plan in the future. In order to complete this objective, the resource planning process is comprised of a two phase extensive process that takes into consideration numerous factors, both current and future, related to issues such as customer costs, fuel costs, renewables, environmental requirements and unknowns, demand side management (DSM), energy efficiency (EE), potential technology shifts, load and energy changes, and capital cost of new central station facilities. This Appendix A discusses the process specifically designed to develop the robust resource plan.

The resource planning process is performed in two phases: sensitivity analysis and scenario analysis. Below is a brief overview of the resource planning process, followed by a more detailed discussion of each phase of the analysis.

Resource Planning Process Overview

The resource planning process can be seen in a simplistic format in Figure A-1 below.

Figure A-1. Integrated Resource Planning Process Flowchart



The sensitivity analysis is based on the expertise of numerous individuals throughout PEC's organization that provide input and knowledge relative to the key drivers that are, or may influence the plan. These key drivers are then utilized to stress the models to determine which of the drivers are "movers" and which are "shakers." This mover/shaker analysis results in the development of potential alternative plans that can then be utilized in the scenario analysis.

The scenario analysis contemplates and develops future states that bound the potential outcomes of the key drivers such as load, energy, escalations, nuclear capital costs, fuel costs, and carbon costs. The alternative plans that are developed in the sensitivity analysis are then tested in each scenario. By testing each of these alternative plans in each of the scenarios, it can be determined how each of the plans fare in each scenario and in aggregate to all scenarios. The ranking of

each plan in each scenario is performed using key attributes in the categories of customer cost and environmental. In short, the scenario analysis develops bounding future potential states and subjects the alternative plans to the future states such that they can be ranked relative to each other based on key attributes in the customer cost and environmental categories.

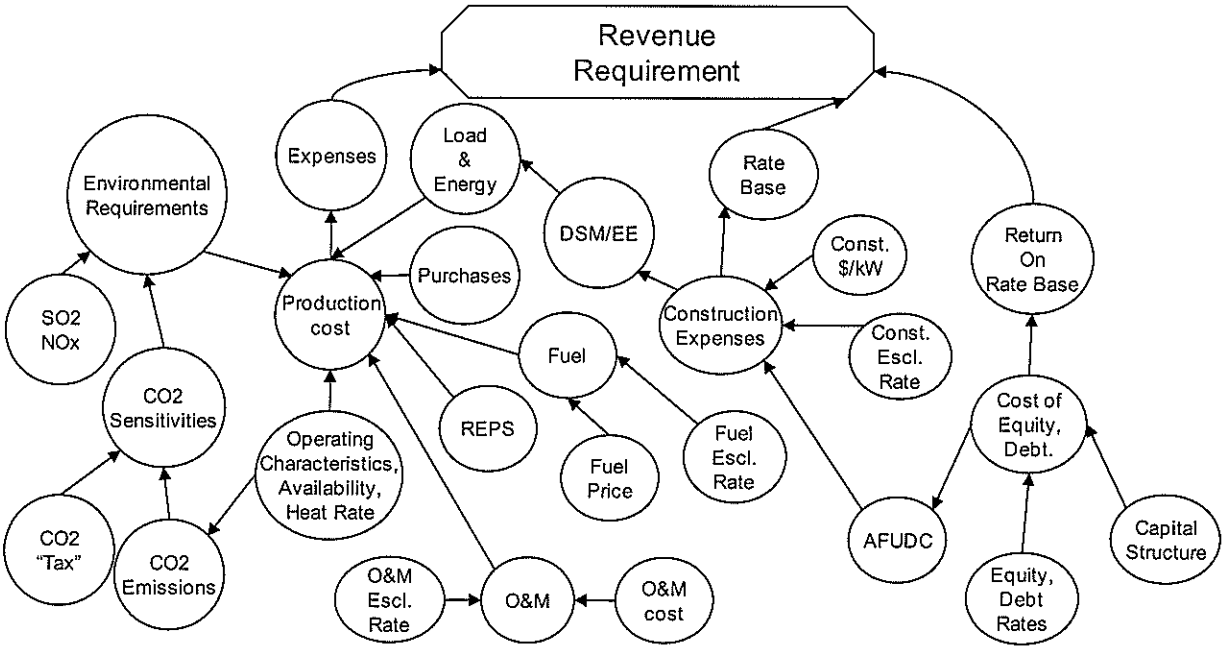
Each of the phases of the process is explored in more detail with results and supporting information throughout the remainder of Appendix A.

Sensitivity Analysis

There is vast uncertainty today as to what the future will hold—seemingly more than any time in the past—especially with respect to utility resource plans. The purpose of the sensitivity analysis in the resource planning process is to identify the uncertainties that, depending on their outcomes, could influence resource plan decisions.

The first step in the sensitivity analysis incorporated the use of an influence diagram. The influence diagram, Figure A-2, shows many factors and how they interrelate. In addition to the influence diagram, emerging issues in the current planning environment were identified. Some of the emerging issues include the following: dramatic increase in commodity costs; carbon legislation has been pushed to the forefront of many discussions; SO_2 and NO_x legislation, though more certain in NC due to the NC Clean Smokestacks law, has increased in uncertainty due to the upset of CAIR; gasoline costs are driving research and development of plug in hybrids which could impact energy usage and demand; DSM and EE programs are being aggressively promoted and advanced by PEC (though customer participation and acceptance are still uncertain); renewables are part of the plan, but the ability of renewables to compete beyond the REPS requirements is uncertain given the non-dispatchable nature of the technologies; storage technologies are being explored given they are a significant lynchpin to the effectiveness of non-dispatchable technologies and utilization of baseload generation; fuel costs have risen dramatically; and the list continues.

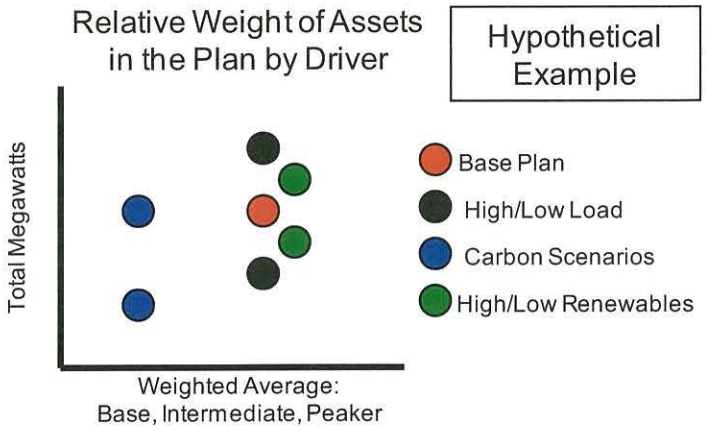
Figure A-2.



Influence Diagram for Resource Options

It is important to identify which of these uncertainties and emerging issues can significantly alter the direction that would be required by a resource plan. To pinpoint which of the uncertainties and emerging issues are key drivers, the expertise of numerous individuals throughout PEC's organization was taken into consideration. Each key driver is then independently stressed in order to determine which of the drivers are "movers" and which are "shakers." It is important to understand the difference between a mover and shaker. In general, a mover has less impact on the resource plan and can be adapted to more easily; whereas, a shaker has a more significant impact on the resource plan and may require new directions to be taken. Figure A-3 below provides a graphical representation and general explanation of a mover versus a shaker. For example, load can vary significantly, and though it has a dramatic impact, it rarely results in a significantly different resource mix, only in the timing of the resources, and thus load would be considered a mover. On the other hand, environmental changes such as CO_2 legislation can massively alter resource plans and their components and can require a greater change, which translates to greater risk and would thus be considered a shaker.

Figure A-3. Movers vs. Shakers Example



Movers can be adapted to more easily since the type of resources in the plan do not significantly change, only the timing and/or frequency change.

Shakers cause new directions to be taken, demand course correction, and typically require greater analysis and investigation.

The key drivers identified in the sensitivity analysis are shown in Figure A-4, below. The majority of the drivers result in some plan modification; however, only five significant variations occur. Figure A-5 shows the alternative plans that resulted from the sensitivity analysis that was performed. Each of these plans are the result of an optimization completed with Strategist taking into consideration operational criteria, construction schedules, capital costs, fuel costs, emissions costs, and more. The resource options available to be picked in the optimization analysis are shown in Figure A-6, which is the result of the "Screening of Generation Alternatives," detailed in the main text. Each plan contains an incremental 1000 MW of DSM and EE programs over the next ten years. It is a fundamental assumption that PEC will continue to pursue the doubling of its DSM and EE programs. Figure A-6R shows the renewable capacity used in the "target" renewables sensitivity below. Several of the sensitivities also take into consideration potential technology, regulatory, and environmental planning shifts. A more detailed discussion of each plan follows.

Figure A-4. Sensitivities Analyzed

Driver	Sensitivity
Fuel Prices	Low – All Fuels
	Base – All Fuels
	High – All Fuels
Construction Escalation	Low – Confidential
	Median – Confidential
	High – Confidential
Load & Energy	Low Growth
	Median Growth
	High Growth
Load shape	High Load Factor
	Low Load Factor
CO_2 Prices	Low
	Medium
	High
Nuclear Cost	Current
	High (30% increase)
Renewables*	Target
	High
Coal CO_2 Mature*	Coal with CO_2 Capture at only 20% over conventional coal unit cost.

See Supporting Information Section below that provides data for these sensitivities.

*Driven by emerging issues and technology shift potentials.

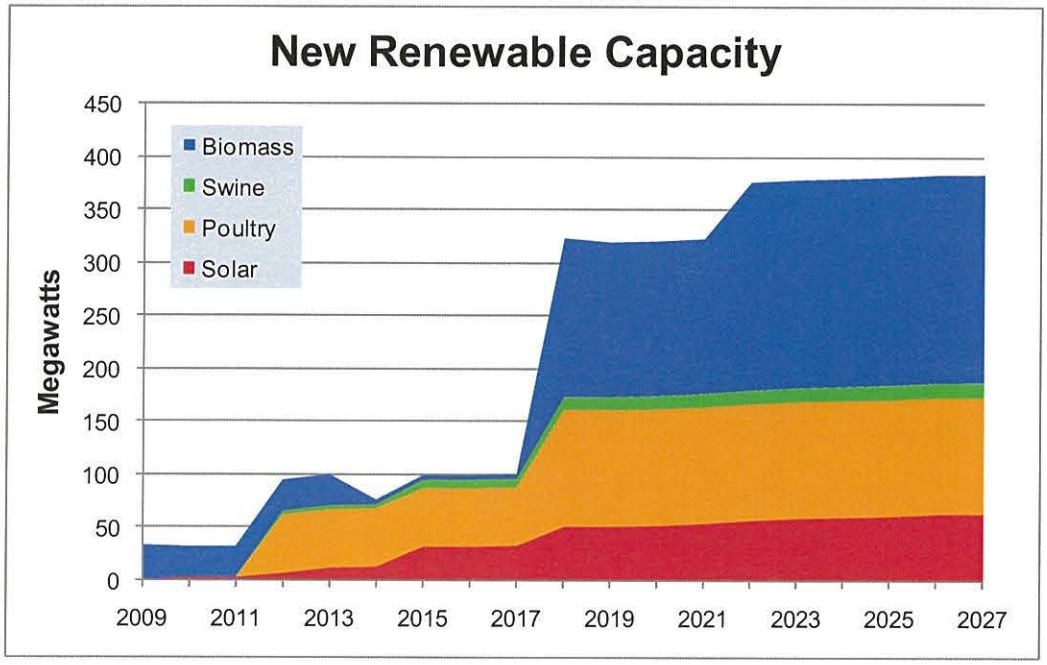
Figure A-5. Alternative Plans for Scenario Analysis

	Plan A	Plan B	Plan C	Plan D	Plan E	
2008						2008
2009	Wayne CT (Oil)	Wayne CT (Oil)	Wayne CT (Oil)	Wayne CT (Oil)	Wayne CT (Oil)	2009
2010						2010
2011	3 Fast Start CTs CC Richmond	3 Fast Start CTs CC Richmond	3 Fast Start CTs CC Richmond	3 Fast Start CTs CC Richmond	3 Fast Start CTs CC Richmond	2011
2012						2012
2013						2013
2014	CT 190	CT 190		CT 190	CT 190	2014
2015	CT 190	CT 190	CT 190	CT 190	CT 190	2015
2016			CT 190			2016
2017	CT 190	CT 190	CT 190	CT 190	CT 190	2017
2018	CT 190	CT 190		CC 2X1	CT 190	2018
2019	2 CT 190	ALWR	CT 190		Coal CO2 Capture	2019
2020	CT 190	ALWR	CT 190			2020
2021	2 CT 190		2 CT 190	CC 2X1	Coal CO2 Capture	2021
2022	CT 190		CT 190			2022
2023	CC 2X1		2 CT 190	CC 2X1		2023
2024			2 CT 190		CC 2X1	2024
2025	CC 2X1	CT 190	CT 190	CC 2X1	CT 190	2025
2026		2 CT 190	2 CT 190		2 CT 190	2026
2027						2027

Figure A-6. Resource Options from Alternative Plans

Unit Type	Winter	Summer
Fast Start CT	49	43
CT 190	201	169
CC 2x1	674	606
Coal CO2 Capture (PC w/CO2)	697	697
Circulating Fludized Bed	900	900
Supercritical Coal	850	850
ALWR - Nuclear	878	847

Figure A-6R. Renewable Capacity – Target Sensitivity



Plan A

Plan A contains a mix of combustion turbine and combined cycle generation. These resources are cost-effective in cases when the parameters are at the mid level and also when fuel prices and CO_2 prices are low and nuclear construction costs are high.

Plan B

Plan B contains two nuclear units. This plan resulted from the high CO_2 and high fuel price sensitivities. Nuclear units are assumed to be jointly owned, with PEC owning an approximate 80% majority share.

Plan C

Plan C was developed assuming significant additional renewable resources. Figure A-6R shows the total renewable capacity added to plan C. In the Supporting Information Section below the energy and capacity for both the Target and High renewable sensitivities can be seen. These amounts are not necessarily an indication of the potential to acquire these renewables and given the lack of dispatchability of many of the renewables the capacity cannot all be counted to reserve margin capacity. This plan was developed to show the potential impact of a large amount of renewables, assuming they could be obtained. The "must take," nature of a significant portion of the renewable energy resources results in the need for peaking capacity.

Plan D

Plan D consists mainly of combined cycle resources. This type of capacity was indicated in the high load growth and high load factor cases, where intermediate-to-baseload resources are needed.

Plan E
Plan E is designed to examine the impact of coal units in the resource plan. Because of the concerns about CO_2 emissions it was assumed the only way coal capacity could be added was if it employed carbon sequestration technology, minimizing CO_2 emissions. Though this technology is not available today, this plan assumes accelerated developed, resulting in cost-effective deployment of the technology within the next 10 years.

The development of the alternative plans through the sensitivity analysis is informative but as mentioned previously these plans must be evaluated through the scenario analysis to determine the most robust plan.

Scenario Analysis

The scenario analysis phase contemplates and develops future states that bound the potential outcomes of the key drivers such as load, energy, escalations, nuclear capital costs, fuel costs, and carbon costs. The scenario analysis relies on PEC experts to determine which future states are most probable and how the future states would evolve. The alternative plans developed in the sensitivity analysis are stressed in each scenario. By testing each of these alternative plans in each of the scenarios, how each of the plans fare in each scenario and in aggregate to all scenarios can be determined. Figure A-7 below outlines the scenarios and key uncertainties in each of these scenarios. The scenarios reflect multiple uncertainties moving in concert instead of changing a single variable at a time as was done in the sensitivity analysis.

Figure A-7. Scenarios Used to Stress Alternative Plans

Scenario	Definition	Fuel Prices	Nuclear Cost	Escalation	CO2	Load	Energy
Low Stress	*Carbon legislation not enacted or very minor. *Commodity markets come back into parity and growth continues. *Escalation rates are at the lower end of the range. *Renewable set asides completed. *Fuels prices continue at low case.	Low all	Current Cost	Low	Low CO2	Mid point	Gradual High energy growth (high load factor)
CO2 Moderate	*Legislation drives a carbon tax (or cap) that results in fuel price shifts (fuel price parity is not maintained) and continues the demand for nuclear.	Gas = avg. of mid/high; others mid	Current Cost	Mid	Mid point CO2	Mid point	Mid point
CO2 Aggressive (Strict Climate - High Cost)	*Legislation drives a dramatic carbon tax (or cap) that results in fuel price shift (fuel price parity is not maintained). *Demand for nuclear increased which drives up prices. *Energy and load reductions due to technological (personal renewables) and economic factors.	Gas = High Oil= Mid Coal = Low	Nuclear High Cost up 30%	High	High CO2	Gradual Decline 3	Gradual Decline 3
Current Trends	Current world scenario including CO2 tax mid case.	Mid point all	Current Cost	Mid	Mid point CO2	Mid point	Mid point
PHEV	Load profile flattens through valley fill from technology shift associated with PHEV and due to petrol prices.	Mid point all	Current Cost	Mid	Mid point CO2	Mid point	PHEV energy
Load Cliff	Significant loss of load through industrial customers and lessening load growth.	Mid point all	Current Cost	Mid	Mid point CO2	Gradual Decline 3	Gradual Decline 3

Note: Informaiton associated with each case can be seen in the Supporting Informaiton Section. Mid referes to the median or base case. Escalations are construction cost escalations as seen in the senisitivity table above. PHEV is plug in hybrid electric vehicles.

As can be seen from Figure A-7, a broad range of future scenarios was developed. These scenarios include everything from a case where, in effect, costs are low and "life is easy" (the Low Stress scenario) to a case where costs are very high and "life is challenging" (the CO_2 Aggressive scenario). The broad range of future scenarios ensures that each plan is tested broadly to determine which plan is the most robust; that is, which plan performs the best, given all of the risks and uncertainties the future holds.

To determine which plan is most robust, the alternative plans are compared to one another in two general categories using seven key attributes. The general categories are Customer Cost and Environmental. These categories are described by several attributes that are used to measure the "goodness" of the alternative plans relative to each other. A brief description of the attributes is given below.

Customer Cost Category

The key attributes in the Customer Cost category are total cost, system fuel price volatility, and price growth. The total cost of each alternative plan is determined by the cumulative present value of revenue requirements (CPVRR), and is an indication of the cost of the plan to the customer over the long term. The system fuel price volatility is the standard deviation in system average fuel prices based on a normal distribution of prices around the base fuel price forecast. The price growth attribute is measured by the geometric mean growth of annual prices based on the annual revenue requirements.

Environmental Category
The key attributes in the Environmental category are SO_2, NO_x, Hg, and CO_2 emissions. Each of the emissions is summed over the study period.

Utility Functions
Since two different evaluation categories are used to evaluate each plan, a method of incorporating the trade-offs of one category against the other is needed. The type of analysis used is known as utility function analysis. In this type of analysis, the different categories are assigned weights, with the sum of the weights equaling one. In this fashion, the relative importance of each category in the decision process is identified. Since each category is described by more than one attribute, these attributes are also assigned weights to identify their importance relative to other attributes within a category. The weights of the attributes within a category also sum to a value of one. The weights for the categories and attributes were determined from a survey of Company experts and are shown in Figure A-8 below.

Figure A-8. Attributes Used to Rank Alternative Plans

Customer	**70%**
Total Cost	40%
Price Growth	30%
System Fuel Price Volatility	30%
Environmental	**30%**
SO_2	10%
NOx	5%
CO_2	70%
Mercury	15%

Because the attributes have different units of measure, they must be unitized before they can be compared to other attributes. This is accomplished by identifying the range for each attribute, from the worst possible outcome to the best possible outcome, among all the alternative plans. This range is used as a basis to scale the possible outcomes for each attribute to values between zero and one. Thus, the results are non-dimensional and the different attributes can be combined and evaluated simultaneously.

Scenario Analysis Results

The results of the plans being tested under the scenarios discussed above and being weighted by the key attributes can be seen in Figure A-9. Figure A-9 shows the relative rank of each plan from 1 to 5, with 1 being the best plan in each scenario and 5 being the worst plan in each scenario. The total ranking, which is calculated by summing the rankings of each plan across all scenarios, is also shown to the right of the top table. The rankings show that Plan B is the top ranked plan in all but two scenarios and is the top ranked plan in total by a wide margin. Plan B is the top ranked plan in many of the scenarios because the nuclear units are able to dampen fuel volatility and emissions more than any other technology.

Figure A-9. Scenario Analysis Results

Overall Best Plan

Scenario					
Low Stress	CO2 Moderate	CO2 Aggressive	Current Trends	PHEV	Load Drop
CT/CC	Nuclear	Renewable	Nuclear	Nuclear	Nuclear

Rank of Each Plan

	Scenario						
	Low Stress	CO2 Moderate	CO2 Aggressive	Current Trends	PHEV	Load Drop	Totals
Plan A - Current Base	3	3	3	3	3	3	18
Plan B - Nuclear	2	1	5	1	1	1	11
Plan C - Renewable	5	2	1	4	4	2	18
Plan D - CT/CC	1	4	4	2	2	4	17
Plan E - Coal -CO2	4	5	2	5	5	5	26

Best Plan for Each Scenario by Attribute Group

	Scenario					
	Low Stress	CO2 Moderate	CO2 Aggressive	Current Trends	PHEV	Load Drop
Customer Cost	CT/CC	Nuclear	Renewable	Nuclear	Nuclear	Renewable
Environmental	Nuclear	Nuclear	Nuclear	Nuclear	Nuclear	Nuclear

It should be noted that in the CO2 aggressive case, the capital cost of the nuclear units was increased by 30% yet the costs of all other technologies were kept the same. In hindsight it would appear that if carbon costs increased this significantly that commodity cost for other competitive carbon reduction technologies such as renewables, CC, and carbon sequestration coal should have increased by some percentage as well, which would have resulted in plan rankings similar to the CO2 moderate case as would be expected. The result of this refinement would simply be that Plan B was still the overall best plan and all the other plans would move down slightly.

The supporting information section below contains the results of each scenario, and many of the inputs to these scenarios and sensitivities.

Sensitivity Analysis of Weights

The results were further tested by performing an additional sensitivity to the weights assigned to the attribute categories. This was accomplished by varying the weight assigned to an attribute category and modifying the other category weight appropriately to ensure they still sum to one. For example if the Customer Cost category is being evaluated at 40%, the weight assigned to the Environmental category is thus modified to 60%. In this manner, the weights were changed until a different plan became the highest ranked plan for each scenario. The results of this analysis are shown in Figure A-10, below. The figure shows the best overall plan in each scenario usually does not change when the Customer Cost weight increases, even to 100%, or is reduced all the way to zero (no change in the best plan is shown as --).

Figure A-10. Sensitivity of Weightings for Each Scenario

	Scenario					
	Low Stress	CO2 Moderate	CO2 Aggressive	Current Trends	PHEV	Load Drop
Best Overall Plan	CT/CC	Nuclear	Renewable	Nuclear	Nuclear	Nuclear
Customer Cost (70%)						
High Weight changes to:	100%	100%	100%	100%	100%	83%
Best Plan becomes:	--	--	--	--	--	Renewable
Low Weight changes to:	50%	0%	64%	0%	0%	0%
Best Plan becomes:	Nuclear	--	Coal -CO2	--	--	--
Environmental (30%)						
High Weight changes to:	50%	100%	36%	100%	100%	100%
Best Plan becomes:	Nuclear	--	Coal -CO2	--	--	--
Low Weight changes to:	0%	0%	0%	0%	0%	17%
Best Plan becomes:	--	--	--	--	--	Renewable

Summary

A robust plan minimizes the adverse impacts of unforeseen changes, and produces acceptable results for a broad range of events. This is why different scenarios of load, energy, fuel, construction cost escalation, environmental, technology shifts and other factors were taken into consideration when testing the plans to determine robustness. Another important benefit of such broad scenario analysis is that the integrity of the plan is maintained even with moderate changes in inputs used in the analysis, such as load.

As seen from the results above, Plan B, which includes combustion turbines, combined cycle, nuclear, renewables, as well as additional DSM and EE, accomplishes the objective of a robust resource plan. Thus, it is the basis for the preferred resource plan shown in the IRP. It is not surprising that this balanced solution provides a more robust plan than that which is heavily biased towards any one solution.

The other significant benefit of this type of analysis is it allows PEC to determine not only which plan is the most robust, but also what other factors need to be focused on and why. From these results, it is easy to see that nuclear needs to be a continued focus for PEC. It also reinforces that technology advancements that could make renewables more competitive should be closely watched. Finally, this process provides a foundation for the next IRP evaluation as the future continues to evolve and change.

Supporting Information Section

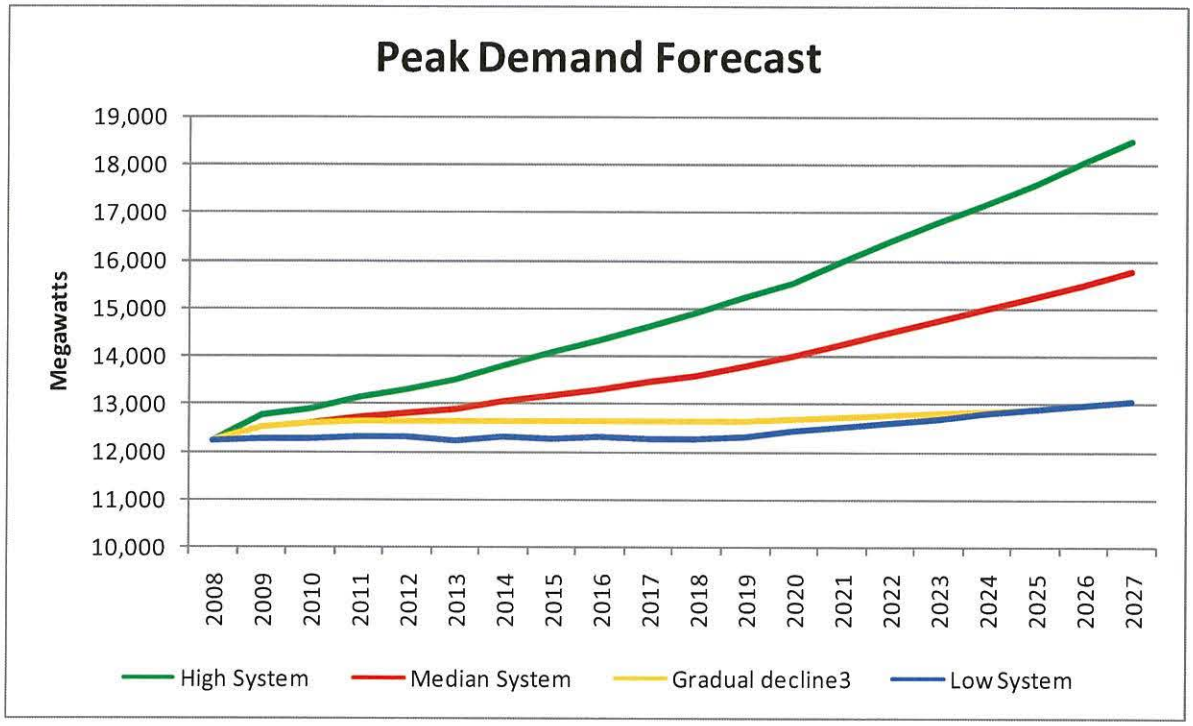
Fuel Curves Utilized

This information is being filed as confidential.

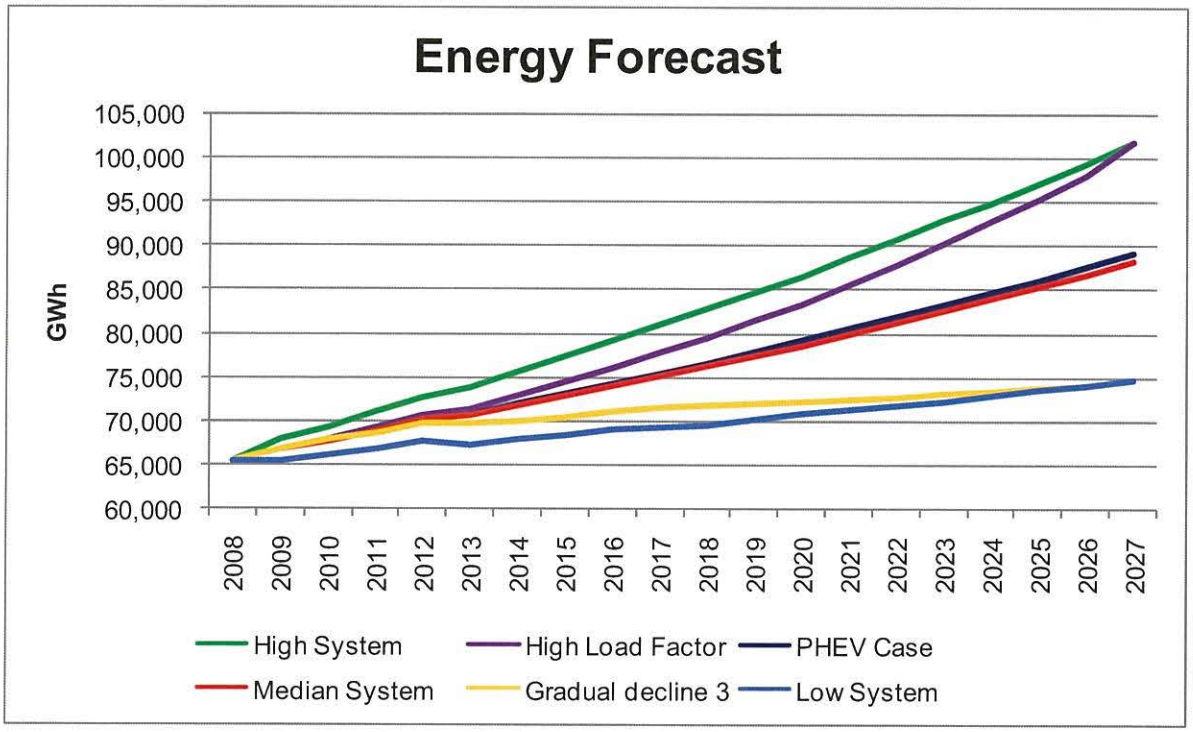
CO_2 Curves Utilized

This information is being filed as confidential.

Load Curves Utilized

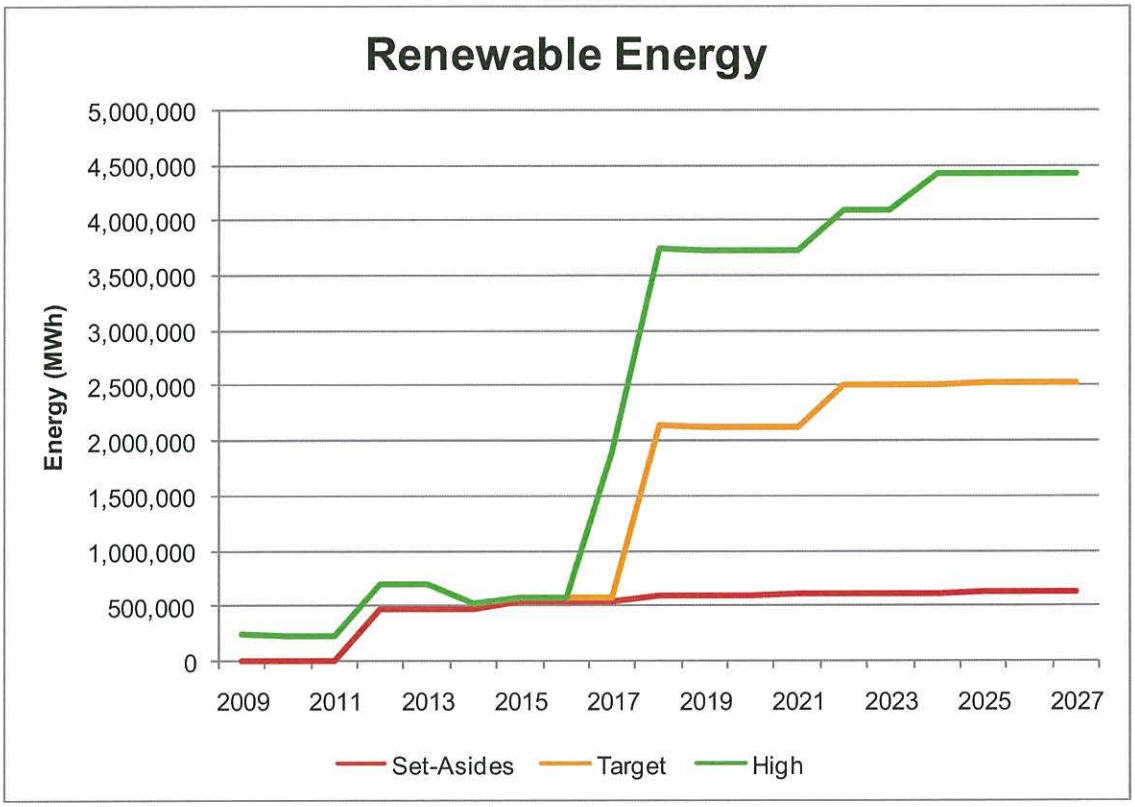


Energy Curves Utilized

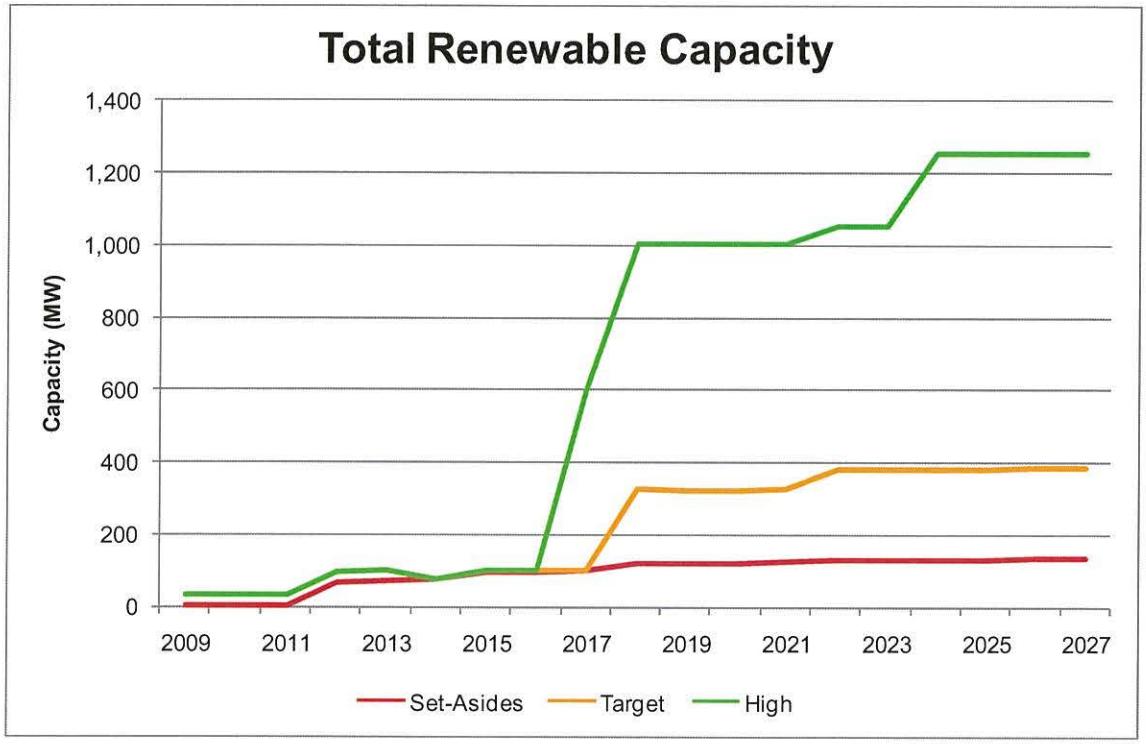


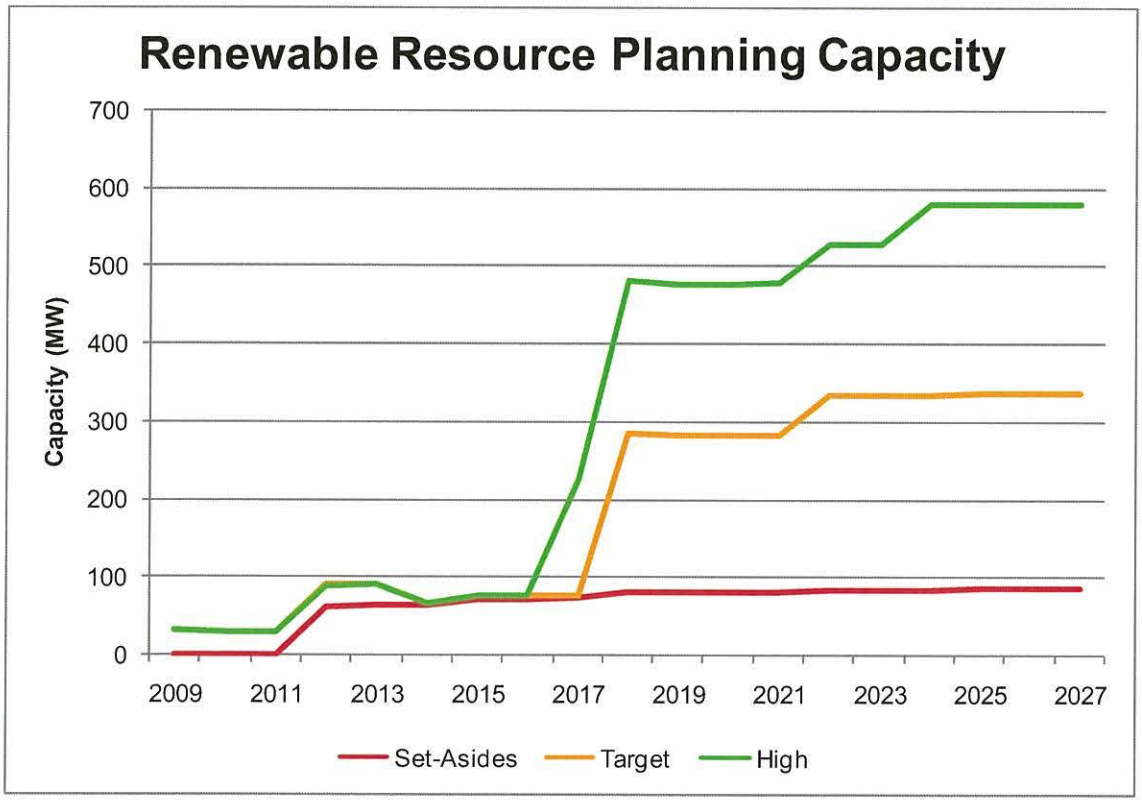
Renewables Capacity and Energy Utilized in Sensitivities:

- Much of the renewable capacity is biomass as wind and solar provide energy but little to no capacity benefit. These amounts do not include the benefit from EE as EE is in all plans.
- Set asides represent requirements relative to Senate Bill 3 set-asides.
- Existing hydro energy is included in all plans.



- Much of the renewable capacity would not count as resource capacity given it is not dispatchable. This can be seen in comparing the two charts below which show total renewable capacity included in the plans and capacity counted towards reserve margins.


Total Renewable Capacity
1,400
1,200
1,000
800
600
400
200
0
Capacity (MW)
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
Set-Asides
Target
High


Renewable Resource Planning Capacity
700
600
500
400
300
200
100
0
Capacity (MW)
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
Set-Asides
Target
High

Scenario Analysis Results

LOW STRESS	Objective	Plan A	Plan B	Plan C	Plan D	Plan E
Customer						
CPVRR	min	43,491	48,887	45,039	43,684	47,324
Geometric mean of price growth	min	0.55%	1.18%	0.71%	0.54%	1.08%
System fuel price volatility	min	6.30	4.78	6.10	6.11	5.45
Environment						
SO2	min	938,780	842,902	936,922	853,087	918,832
NOx	min	403,055	353,466	406,656	361,219	381,838
Hg	min	12,990	12,155	12,981	12,241	12,388
CO2	min	810,365	726,770	801,784	774,955	750,391
Score 0-10 Points Based on Value within Range (best=10, worst=0, interpolate between)						
Customer		6.93	3.00	5.44	7.23	3.31
CPVRR		10.00	0.00	7.13	9.64	2.90
Geometric mean of prices		9.78	0.00	7.30	10.00	1.58
System fuel price volatility		0.00	10.00	1.33	1.24	5.58
Environment		0.03	10.00	0.76	5.63	6.55
SO2		0.00	10.00	0.19	8.94	2.08
NOx		0.68	10.00	0.00	8.54	4.67
Hg		0.00	10.00	0.12	8.97	7.21
CO2		0.00	10.00	1.03	4.24	7.17
Sum of averages (equal weighting)		8.13	12.00	7.32	15.85	9.12
Weighted score		4.86	5.10	4.04	6.75	4.28
Rank		3	2	5	1	4

CO2 Moderate	Objective	1-Plan A	2-Plan B	3-Plan C	4-Plan D	5-Plan E
Customer						
CPVRR	min	65,770	65,203	65,867	66,100	67,105
Geometric mean of price growth	min	3.08%	2.97%	3.08%	3.09%	3.22%
System fuel price volatility	min	10.10	6.10	9.63	9.34	8.54
Environment						
SO2	min	1,183,150	1,057,479	1,151,111	1,183,572	1,153,157
NOx	min	462,890	405,623	452,229	458,112	441,795
Hg	min	14,559	13,491	14,315	14,554	13,899
CO2	min	807,597	720,232	790,623	800,080	749,078

Score 0-10 Points Based on Value within Range (best=10, worst=0, interpolate between)					
Customer	4.50	10.00	4.69	4.19	1.17
CPVRR	7.02	10.00	6.51	5.28	0.00
Geometric mean of prices	5.65	10.00	5.78	5.02	0.00
System fuel price volatility	0.00	10.00	1.16	1.90	3.91
Environment	0.00	10.00	2.05	0.65	6.04
SO2	0.03	10.00	2.57	0.00	2.41
NOx	0.00	10.00	1.86	0.83	3.68
Hg	0.00	10.00	2.28	0.05	6.18
CO2	0.00	10.00	1.94	0.86	6.70
Sum of averages (equal weighting)	5.88	18.67	6.86	6.88	7.52
Weighted score	3.15	10.00	3.90	3.13	2.63
Rank	3	1	2	4	5

CO2 Aggressive	Objective	Plan A	Plan B	Plan C	Plan D	Plan E
Customer						
CPVRR	min	61,055	65,203	60,140	62,224	61,080
Geometric mean of price growth	min	3.42%	3.53%	3.29%	3.51%	3.37%
System fuel price volatility	min	4.45	4.80	4.04	4.14	4.16
Environment						
SO2	min	1,073,879	926,488	1,035,030	1,074,243	1,023,943
NOx	min	414,858	350,173	399,689	413,120	387,444
Hg	min	13,672	12,109	13,322	13,669	12,652
CO2	min	729,806	630,090	708,339	726,057	662,631

Score 0-10 Points Based on Value within Range (best=10, worst=0, interpolate between)					
Customer	6.08	0.00	10.00	5.20	7.82
CPVRR	8.19	0.00	10.00	5.88	8.14
Geometric mean of prices	4.72	0.00	10.00	0.74	6.71
System fuel price volatility	4.63	0.00	10.00	8.75	8.51
Environment	0.00	10.00	2.23	0.28	6.25
SO2	0.02	10.00	2.65	0.00	3.40
NOx	0.00	10.00	2.35	0.27	4.24
Hg	0.00	10.00	2.24	0.02	6.53
CO2	0.00	10.00	2.15	0.38	6.74
Sum of averages (equal weighting)	6.51	12.00	10.35	6.24	12.90
Weighted score	4.26	3.00	7.67	3.72	7.35
Rank	3	5	1	4	2

Current Trends	Objective	Plan A	Plan B	Plan C	Plan D	Plan E
Customer						
CPVRR	min	61,692	62,952	62,218	62,044	64,442
Geometric mean of price growth	min	2.72%	2.80%	2.77%	2.73%	3.01%
System fuel price volatility	min	8.83	5.61	8.29	8.48	7.71
Environment						
SO2	min	1,023,001	921,690	1,016,442	970,319	999,238
NOx	min	408,698	359,018	407,148	384,086	388,681
Hg	min	13,526	12,516	13,436	13,185	12,816
CO2	min	777,189	692,080	765,496	757,782	717,359
Score 0-10 Points Based on Value within Range (best=10, worst=0, interpolate between)						
Customer		7.00	7.39	6.24	6.78	1.04
CPVRR		10.00	5.42	8.09	8.72	0.00
Geometric mean of prices		10.00	7.42	8.35	9.90	0.00
System fuel price volatility		0.00	10.00	1.68	1.08	3.48
Environment		0.00	10.00	1.18	2.87	6.41
SO2		0.00	10.00	0.65	5.20	2.35
NOx		0.00	10.00	0.31	4.95	4.03
Hg		0.00	10.00	0.89	3.37	7.03
CO2		0.00	10.00	1.37	2.28	7.03
Sum of averages (equal weighting)		8.00	16.57	6.43	11.89	7.80
Weighted score		4.90	8.18	4.72	5.61	2.65
Rank		3	1	4	2	5

PHEV	Objective	Plan A	Plan B	Plan C	Plan D	Plan E
Customer						
CPVRR	min	62,410	63,606	62,987	62,689	65,100
Geometric mean of price growth	min	2.73%	2.80%	2.79%	2.73%	3.01%
System fuel price volatility	min	9.01	5.70	8.49	8.61	7.83
Environment						
SO2	min	1,033,275	932,444	1,026,752	980,088	1,009,868
NOx	min	413,532	363,813	412,151	388,416	393,452
Hg	min	13,602	12,616	13,514	13,263	12,910
CO2	min	783,791	699,112	772,225	764,121	724,220
Score 0-10 Points Based on Value within Range (best=10, worst=0, interpolate between)						
Customer		6.96	7.45	5.99	6.94	1.07
CPVRR		10.00	5.55	7.86	8.96	0.00
Geometric mean of prices		9.85	7.42	7.95	10.00	0.00
System fuel price volatility		0.00	10.00	1.55	1.20	3.56
Environment		0.00	10.00	1.17	2.92	6.41
SO2		0.00	10.00	0.65	5.27	2.32
NOx		0.00	10.00	0.28	5.05	4.04
Hg		0.00	10.00	0.90	3.44	7.02
CO2		0.00	10.00	1.37	2.32	7.03
Sum of averages (equal weighting)		7.97	16.59	6.27	12.05	7.82
Weighted score		4.87	8.21	4.55	5.74	2.67
Rank		3	1	4	2	5

Load Drop	Objective	Plan A	Plan B	Plan C	Plan D	Plan E
Customer						
CPVRR	min	52,961	54,950	52,943	54,072	56,533
Geometric mean of price growth	min	2.63%	2.77%	2.59%	2.72%	3.05%
System fuel price volatility	min	6.72	5.06	5.99	6.86	6.29
Environment						
SO2	min	902,670	796,074	892,821	860,381	876,275
NOx	min	350,488	302,228	346,140	332,966	332,173
Hg	min	12,521	11,239	12,389	12,196	11,620
CO2	min	694,206	604,160	680,298	678,615	637,283

Score 0-10 Points Based on Value within Range (best=10, worst=0, interpolate between)					
Customer	6.96	6.58	8.45	4.89	0.94
CPVRR	9.95	4.41	10.00	6.86	0.00
Geometric mean of prices	9.20	6.05	10.00	7.14	0.00
System fuel price volatility	0.75	10.00	4.85	0.00	3.14
Environment	0.00	10.00	1.37	2.17	5.92
SO2	0.00	10.00	0.92	3.97	2.48
NOx	0.00	10.00	0.90	3.63	3.79
Hg	0.00	10.00	1.03	2.54	7.03
CO2	0.00	10.00	1.54	1.73	6.32
Sum of averages (equal weighting)	7.98	17.09	8.07	9.77	7.53
Weighted score	4.88	7.61	6.33	4.07	2.44
Rank	3	1	2	4	5

Progress Energy

Progress Energy Carolinas Integrated Resource Plan

Appendix B
PEC Owned Generation

September 1, 2008

PEC has a diverse fleet of generating facilities to meet customer demands and maintain reliability. Below are tables detailing PEC's existing, planned, and planned undesignated generation capacity as well as units to be retired and planned uprates.

Existing Generating Units and Ratings (1)
All Generating Unit Ratings are as of December 31, 2007

Coal

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Asheville	1	196	191	Arden, NC	Coal	Base
Asheville	2	193	185	Arden, NC	Coal	Base
Cape Fear	5	148	144	Moncure, NC	Coal	Base
Cape Fear	6	175	172	Moncure, NC	Coal	Intermediate
Lee	1	81	74	Goldsboro, NC	Coal	Intermediate
Lee	2	80	77	Goldsboro, NC	Coal	Intermediate
Lee	3	257	248	Goldsboro, NC	Coal	Intermediate
Mayo *(2)*	1	749	742	Roxboro, NC	Coal	Base
Robinson	1	184	176	Hartsville, SC	Coal	Base
Roxboro	1	386	369	Semora, NC	Coal	Base
Roxboro	2	675	671	Semora, NC	Coal	Base
Roxboro	3	720	705	Semora, NC	Coal	Base
Roxboro *(2)*	4	711	698	Semora, NC	Coal	Base
Sutton	1	99	93	Wilmington, NC	Coal	Intermediate
Sutton	2	108	102	Wilmington, NC	Coal	Intermediate
Sutton	3	416	403	Wilmington, NC	Coal	Intermediate
Weatherspoon	1	47	48	Lumberton, NC	Coal	Intermediate
Weatherspoon	2	51	49	Lumberton, NC	Coal	Intermediate
Weatherspoon	3	82	76	Lumberton, NC	Coal	Intermediate
Total Coal		5,358	5,223			

Combustion Turbines

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Asheville	3	184	168	Arden, NC	Natural Gas/Oil	Peaking
Asheville	4	184	167	Arden, NC	Natural Gas/Oil	Peaking
Blewett	1	17	13	Lilesville, NC	Oil	Peaking
Blewett	2	17	13	Lilesville, NC	Oil	Peaking
Blewett	3	18	13	Lilesville, NC	Oil	Peaking
Blewett	4	17	13	Lilesville, NC	Oil	Peaking
Darlington	1	65	56	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	62	49	Hartsville, SC	Oil	Peaking
Darlington	3	65	46	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	4	65	53	Hartsville, SC	Oil	Peaking
Darlington	5	68	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	6	65	50	Hartsville, SC	Oil	Peaking
Darlington	7	72	54	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	69	49	Hartsville, SC	Oil	Peaking
Darlington	9	72	53	Hartsville, SC	Oil	Peaking
Darlington	10	67	51	Hartsville, SC	Oil	Peaking
Darlington	11	69	50	Hartsville, SC	Oil	Peaking
Darlington	12	133	121	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	13	132	114	Hartsville, SC	Natural Gas/Oil	Peaking
Lee	1	18	12	Goldsboro, NC	Oil	Peaking
Lee	2	32	21	Goldsboro, NC	Oil	Peaking
Lee	3	32	21	Goldsboro, NC	Oil	Peaking
Lee	4	32	21	Goldsboro, NC	Oil	Peaking
Morehead	1	18	12	Morehead City, NC	Oil	Peaking
Richmond *(3)*	1	182	156	Hamlet, NC	Natural Gas/Oil	Peaking
Richmond *(3)*	2	181	158	Hamlet, NC	Natural Gas/Oil	Peaking
Richmond *(3)*	3	183	158	Hamlet, NC	Natural Gas/Oil	Peaking
Richmond *(3)*	4	180	160	Hamlet, NC	Natural Gas/Oil	Peaking
Richmond *(3)*	6	184	156	Hamlet, NC	Natural Gas/Oil	Peaking
Robinson	1	18	15	Hartsville, SC	Natural Gas/Oil	Peaking
Sutton	1	18	11	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2A	33	24	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2B	33	24	Wilmington, NC	Oil/Natural Gas	Peaking
Wayne	1	192	170	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	2	189	175	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne *(4)*	3	190	169	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne *(4)*	4	188	165	Goldsboro, NC	Oil/Natural Gas	Peaking
Weatherspoon	1	42	33	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	2	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	3	42	34	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	4	42	33	Lumberton, NC	Natural Gas/Oil	Peaking
Total CT		3,511	2,945			

Combined Cycle

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Cape Fear	1	14	14	Moncure, NC	Oil	Peaking
Cape Fear	1A	14	11	Moncure, NC	Oil	Peaking
Cape Fear	1B	14	10	Moncure, NC	Oil	Peaking
Cape Fear	2	14	14	Moncure, NC	Oil	Peaking
Cape Fear	2A	15	11	Moncure, NC	Oil	Peaking
Cape Fear	2B	14	10	Moncure, NC	Oil	Peaking
Richmond	CT7	175	149	Hamlet, NC	Natural Gas/Oil	Intermediate
Richmond	CT8	175	149	Hamlet, NC	Natural Gas/Oil	Intermediate
Richmond	ST4	182	168	Hamlet, NC	Natural Gas/Oil	Intermediate
Total CC		617	536			

Hydro

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Blewett	1	4	3	Lilesville, NC	Water	Intermediate
Blewett	2	4	3	Lilesville, NC	Water	Intermediate
Blewett	3	4	4	Lilesville, NC	Water	Intermediate
Blewett	4	4	4	Lilesville, NC	Water	Intermediate
Blewett	5	4	4	Lilesville, NC	Water	Intermediate
Blewett	6	5	4	Lilesville, NC	Water	Intermediate
Marshall	1	2	2	Marshall, NC	Water	Intermediate
Marshall	2	3	3	Marshall, NC	Water	Intermediate
Tillery	1	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	2	18	18	Mt. Gilead, NC	Water	Intermediate
Tillery	3	21	21	Mt. Gilead, NC	Water	Intermediate
Tillery	4	26	26	Mt. Gilead, NC	Water	Intermediate
Walters	1	36	36	Waterville, NC	Water	Intermediate
Walters	2	40	40	Waterville, NC	Water	Intermediate
Walters	3	36	36	Waterville, NC	Water	Intermediate
Total Hydro		228	225			

Nuclear

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Brunswick *(2)*	1	975	938	Southport, NC	Uranium	Base
Brunswick *(2)*	2	953	937	Southport, NC	Uranium	Base
Harris *(2)*	1	936	900	New Hill, NC	Uranium	Base
Robinson	2	758	710	Hartsville, SC	Uranium	Base
Total Nuclear		3,622	3,485			
TOTAL PEC SYSTEM		13,345	12,414			

FOOTNOTES:
(1) Ratings reflect compliance with new NERC reliability standards and are gross of co-ownership interest as of 12/31/07.
(2) Jointly-owned by NCEMPA: Roxboro 4 - 12.94%; Mayo 1 - 16.17%; Brunswick 1 - 18.33%; Brunswick 2 - 18.33%; and Harris 1 - 16.17%.
(3) Richmond CTs 1, 2, 3, 4 & 6 summer capacity's will be increased by approximately 4.9 MW each effective June 2008.
(4) Wayne CTs 3 & 4 summer capacity's will be increased by approximately 4.2 MW each effective June 2008.

Planned Designated Generation

Plant Name	Location	Summer Capacity (MW)	Plant Type	Fuel Type	Expected In-Service Date
Wayne County	Goldsboro, NC	157	CT	Oil/Nat gas	06/09
Richmond County	Hamlet, NC	600	CC	Nat gas/oil	06/11

Planned Undesignated Generation

Plant Name	Summer Capacity (MW)	Plant Type	Fuel Type	Expected In-Service Date
Undesignated	126	Peaking	Oil/Nat gas	12/12
Undesignated	169	Peaking	Oil/Nat gas	06/16
Undesignated	1,085	Base	Uranium	06/19
Undesignated	1,085	Base	Uranium	06/20

NOTES:

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

On January 23, 2006, we announced that PEC selected a site at Harris to evaluate for possible future nuclear expansion. We 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. On June 4, 2008, the NRC published the Petition for Leave to Intervene. Petitions to intervene may be filed within 60 days of the notice by anyone whose interest may be affected by the proposed license and who wishes to participate as a party in the proceeding. One petition to intervene was filed with the NRC within the 60-day notice period.

Units to Be Retired

None

Planned Uprates

Unit	Date	Winter MW	Summer MW	Comments
Roxboro 1	01/01/09	11.2	11.2	HPT/IPT upgrade
Brunswick 2	04/12/09	10	10	MSR tube bundle replacement
Robinson 2	06/01/10	20	20	LPT upgrade
Robinson 2	11/01/11	5	5	Condenser upgrade

Operating License Renewal

The plan also includes renewal of operating licenses for two of the Company's hydroelectric plants as well as its four existing nuclear units, as shown below.

Unit & Plant Name	Location	Original Operating License Expiration	Date of Approval	Extended Operating License Expiration
Blewett #1-6	Lilesville, NC	04/30/08	**Pending*	* 2058
Tillery #1-4	Mr. Gilead, NC	04/30/08	**Pending*	* 2058
Robinson #2	Hartsville, SC	07/31/10	04/19/04	07/31/30
Brunswick #2	Southport , NC	12/27/14	06/26/06	12/27/34
Brunswick #1	Southport, NC	09/08/16	06/26/06	09/08/36
Harris #1	New Hill, NC	10/24/26	** *Pending*	** *Requested 10/24/46*

* The license renewal applications for the Blewett and Tillery Plants were filed with the FERC on 04/26/06; approval is expected in 2008. Pending receipt of a new license, these plants are currently perating under a one-year license extension. Although Progress Energy has requested a 50-year license, the FERC may not grant this term.

** The license renewal application for the Harris Nuclear Plant was submitted to the NRC on 11/14/06.

Progress Energy

Progress Energy Carolinas Integrated Resource Plan

Appendix C
Wholesale, Customer Owned Generation, and RFP's

September 1, 2008

This appendix contains firm wholesale purchased power contracts, wholesale sales, customer owned generation capacity, and requests for proposals.

Firm Wholesale Purchased Power Contracts

Purchased Power Contract	Primary Fuel Type	Capacity (MW)	Capacity Designation	Location	Term	Volume of Purchases (MWh) Jul 07-Jun 08
AEP Rockport	Fossil	250	Base	Spencer County, IN	12/31/2009	1,885,386
Broad River CTs # 1-3 *(1)*	Gas	484	Peaking	Gaffney, SC	5/31/2021	499,749
Broad River CTs # 4-5 *(1)*	Gas	324	Peaking	Gaffney, SC	2/28/2022	187,294
Charleston Resources	Waste	8.7	Base	Charleston, SC	10/31/2009	60,023
Primary Energy-Roxboro *(1)*	Fossil/TDF	56	Intermediate	Roxboro, NC	12/31/2009	228,561
Primary Energy-Southport *(1)*	Fossil/TDF	103	Intermediate	Southport, NC	12/31/2009	390,055
New Hanover WASTEC	Waste	7.5	Base	Wilmington, NC	11/16/2008	21,256
Southern Company	Gas	150	Intermediate	Rowan County, NC	1/1/2010-12/31/2010	0
Southern Company	Gas	150	Intermediate	Wansley, GA	1/1/2011-12/31/2011	0
Southern Company (1)	Gas	150	Intermediate	Rowan County, NC	1/1/2010-12/31/2019	0
Stone Container (1)	Fossil/waste wood	20	Base	Florence, SC	12/31/2009	96,014

(1) Assumed to extend beyond expiration date in Resource Plan.

Note: The capacities shown are delivered to the PEC system and may differ from the contracted amount. Renewables purchases are listed in Appendix D.

In addition to the purchases shown above, PEC receives approximately 95 MW from SEPA for their customers located in PEC's control area. The SEPA energy for 2007 was 134,342 MWH.

Wholesale Sales

Customer Name	Current Active Contracts:	Firm or Interruptible	Estimated Peak Demand MW	Contract Commencement date	Contract Termination Date
Town of Black Creek, NC	Full Requirements Power Supply	Native Load Firm	3.2	2/1/2008	12/31/2017
City of Camden, SC	Full Requirements Power Supply	Native Load Firm	50	7/1/2000	12/31/2008
	Full Requirements Power Supply Extension	Native Load Firm	50	1/1/2009	12/31/2013
Fayetteville Public Works Commission	Partial Requirements Power Supply	Native Load Firm	301	7/1/2003	6/31/2012
French Broad EMC	Full Requirements Power Supply	Native Load Firm	90	1/1/2004	12/31/2012
Town of Lucama, NC	Full Requirements Power Supply	Native Load Firm	5.3	2/1/2008	12/31/2017
North Carolina Electric Membership Corporation	NCEMC SOR D	Native Load Firm	420 (2008-2019)	1/1/2005	12/31/2019
	NCEMC SOR A	Native Load Firm	225	1/1/2005	12/31/2015
	NCEMC SOR A Ext.	Native Load Firm	225	1/1/2016	12/31/2022
	NCEMC SOR E	Native Load Firm	225	1/1/2005	12/31/2012
	NCEMC SOR E Ext.	Native Load Firm	275 (2013), 325 (2014-2020), 375 (2021)	1/1/2013	12/31/2021
	NCEMC Intermediate	Native Load Firm	100	4/1/2007	12/31/2011
	NCEMC 7x24 100 MW	Native Load Firm	100	6/1/2008	5/31/2009
	NCEMC PPA	Subordinate to Native Load Firm	750 (2006); 350 (2007); 200 (2008-2011); 300 (2012-2024)	1/1/2005	12/31/2024
North Carolina Eastern Municipal Power Agency	Partial Requirements Power Supply	Native Load Firm	763	1/1/2004	12/31/2009
	Partial Requirements Power Supply	Native Load Firm	763	1/1/2010	12/31/2017
Piedmont EMC	Partial Requirements Power Supply	Native Load Firm	9	9/1/2006	12/31/2021
City of Seneca, SC	Full Requirements Power Supply	Native Load Firm	30	5/16/2002	12/31/2009
Town of Sharpsburg, NC	Full Requirements Power Supply	Native Load Firm	5.6	2/1/2008	12/31/2017
Town of Stantonsburg, NC	Full Requirements Power Supply	Native Load Firm	5.9	2/1/2008	12/31/2017
Town of Waynesville, NC	Full Requirements Power Supply	Native Load Firm	17	1/1/2003	12/31/2009
	Full Requirements Power Supply Extension	Native Load Firm	17	1/1/2010	12/31/2015
Town of Winterville, NC	Full Requirements Power Supply	Native Load Firm	12	3/1/2008	12/31/2017

Note: Contracts, unless information indicates otherwise, are assumed to extend in the forecast.

Customer-Owned Generation Capacity – Accounts Served Under Standby, Curtailable or Net Metering

Status as of March 2008, with adjustment to reflect new participants through July 2008

Facility Name	Location	Primary Fuel Type	Capacity	Designation	Inclusion in PEC Resources
Customer 1	Western NC	Hydro	2,500 kW	Baseload	(1)
Customer 2	Eastern NC	Diesel Fuel	2,250 kW	Baseload	(1)
Customer 3	Eastern NC	Diesel Fuel	1,800 kW	Baseload	(1)
Customer 5	Western NC	Process By-product & Coal	51,000 kW	Baseload	(1)
Customer 6	Eastern NC	Process By -products	27,000 kW	Baseload	(1)
Customer 7	Eastern NC	Fossil Coal	17,000 kW	Baseload	(1)
Customer 8	Eastern NC	Process By-product	60,000 kW	Baseload	(1)
Customer 9	Eastern NC	Natural Gas	46,000 kW	Baseload	(1)
Customer 10	Eastern NC	Process By-product	42,000 kW	Baseload	(1)
Customer 11	Eastern NC	Diesel Fuel	6,000 kW	Peaking	(2)
Customer 12	Eastern NC	Diesel Fuel	2,472 kW	Peaking	(2)
Customer 13	Eastern NC	Diesel Fuel	3,000 kW	Peaking	(2)
Customer 14	Eastern NC	Diesel Fuel	6,500 kW	Peaking	(2)
Customer 15	Eastern NC	Diesel Fuel	2,800 kW	Peaking	(2)
Customer 16	Eastern NC	Diesel Fuel	5,000 kW	Peaking	(2)
Customer 17	Western NC	Solar PV	1.53 kW	Baseload	(3)
Customer 18	Eastern NC	Solar PV	6.00 kW	Baseload	(3)
Customer 19	Eastern NC	Solar PV	2.00 kW	Baseload	(3)
Customer 20	South Carolina	Process By-product & Coal	73,000 kW	Baseload	(1)
Customer 21	South Carolina	Fossil Coal	28,000 kW	Baseload	(1)
Customer 22	South Carolina	Process By-product	27,000 kW	Baseload	(1)
Customer 23	South Carolina	Diesel Fuel	1,500 kW	Peaking	(2)
Customer 24	South Carolina	Diesel Fuel	1,500 kW	Peaking	(2)
System Total			406,332 kW		

(1) Standby Service customer; therefore, load forecast is reduced for generation output.
(2) Included as a curtailable resource.
(3) Net Metering customer; therefore, load forecast is reduced for generation output.

Requests for Proposals

This information is confidential and is provided separately and identified as Exhibit 1 to this Appendix C.

Progress Energy

Progress Energy Carolinas Integrated Resource Plan

Appendix D

Alternative Supply Resources NC REPS Compliance Plan

September 1, 2008

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Rule R8-67

Progress Energy Carolinas', Inc. (PEC's) overall compliance plan approach is to meet the utility specific solar set aside requirements, meet PEC's share of the poultry and swine statewide set aside requirements, reduce load through effective energy efficiency measures, and meet the remainder of the REPS requirements with the most cost effective reliable renewable resources available. While Senate Bill 3 is not entirely clear, it is PEC's belief that its obligation to purchase MWhs produced by swine or poultry resources is not greater than a pro rata share of these statewide set asides.

Specific description of planned actions to comply with G.S. 62-133.8 (b), (c), (d), (e) and (f) for each year are as follows:

G.S. 62-133.8(b): MEETING THE RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARDS FOR ELECTRIC PUBLIC UTILITIES

In an effort to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS), Progress Energy Carolinas, Inc. is consistently evaluating options to meet the overall requirements. Under G.S. 62-133.8 (b), opportunities to meet the REPS requirements can be categorized by PEC ownership of or purchase from renewable generation, use of renewable energy resources at generating facilities, and implementation of energy efficiency measures.

In the case of utility ownership, PEC does not currently own or operate new renewable generating facilities. Future direct or partial ownership will be based on cost-effectiveness and portfolio requirements. PEC does own hydro electric power generating facilities defined as a renewable energy resource under North Carolina Session Law 2007-397 (Senate Bill 3). The energy production from these units contributes to the REPS requirements at no incremental cost to ratepayers. [Reference Exhibit 7 for production forecast].

PEC engages in ongoing research regarding the use of alternative fuels meeting the definition of renewable energy resources at its existing generation facilities. However, introducing alternative fuels in traditional power plants must be proven technically feasible, reliable, and cost effective prior to implementation. To the extent PEC determines the use of alternative fuels is appropriate and fits within the framework of Senate Bill 3, these measures would be included in future compliance plan filings.

Regarding the purchase of energy or RECs from renewable facilities, PEC has adopted a competitive bidding process whereby market participants have an opportunity to propose projects on a continuous basis. PEC has created phases of bid requests and evaluations, described as planning periods. The first planning period and associated RFP was released in November 2007 and closed June 30, 2008. PEC received close to 50 bids from solar, hydro, biomass, wind, and landfill methane generators.

As a result, six (6) contracts were executed with new renewable generators that provide both energy and/or RECs to the REPS compliance plan [see Exhibit 1]. RECs purchased or generated in any year in excess of requirements are banked for use in future years. PEC has not purchased out-of-state RECs at this time, but anticipates future purchases subject to the 25% cap. PEC is accepting bids for the next planning period under an RFP that closes on November 11, 2008.

Lastly, PEC intends to comply with a portion of the Senate Bill 3 requirements by implementing energy efficiency measures. PEC has several proposed demand-side management and energy efficiency programs pending review by the NC Commission. A discussion of existing and proposed programs is included in the demand-side management (DSM) and energy efficiency (EE) section and Appendix E of the IRP. The projected MWhs reduced by the incremental energy efficiency programs have been included in the compliance plan tables included as Exhibit 2. PEC's overall compliance plan table (Exhibit 7) depicts energy efficiency MWhs only up to the 25% and 40% caps in any given year. However, verified energy efficiency MWhs that exceed the specified cap in any given year would be banked and credited in the following year.

G.S. 62-133.8(c): RENEWABLE ENERGY AND ENERGY EFFICIENCY STANDARDS FOR ELECTRIC MEMBERSHIP CORPORATIONS AND MUNICIPALITIES

While this requirement does not apply specifically to PEC, a number of wholesale customers have expressed interest in having PEC plan for compliance on their behalf. The compliance plan table included as Exhibit 3 lists the load of several of PEC's wholesale customers that have specifically requested to be included in PEC's compliance plan.

PEC is working to gather data necessary to develop a compliance strategy for each of these wholesale customers. This information includes the number of customers within each customer class and existing resources that can be credited towards their specific requirements. The costs associated with renewable resources procured to comply with the combined retail loads of PEC and the wholesale customers included in PEC's compliance plan will be allocated across the total MWhs and recovered appropriately. The details of all purchases and the cost allocation to each party will be included in PEC's annual compliance report filing.

G.S. 62-133.8(d): COMPLIANCE WITH REPS REQUIREMENT THROUGH USE OF SOLAR ENERGY RESOURCES

With the objective of meeting the initial 0.02% requirement in 2010, PEC prioritized solar bids within the November 2007 renewable RFP. A significant number of proposals were received and several contracts have been executed. Exhibit 8 shows the anticipated production from both PV and solar thermal projects that vary in technology, size, and geographic location.

Going forward, PEC intends to comply with its growing solar requirement through the purchase of solar energy and solar thermal RECS. PEC is also evaluating direct ownership of solar generation assets and will include those results in future compliance filings.

G.S. 62-133.8(e): COMPLIANCE WITH REPS REQUIREMENT THROUGH USE OF SWINE RESOURCES

In an effort to meet the swine resource set-aside, PEC's November 2007 renewable RFP prioritized swine-fueled projects. Responses have been minimal and the majority of inquiries are associated with small-scale test or pilot projects. Swine farms in eastern North Carolina are served by a number of different electric power suppliers, with many of them located in the territories of the electric membership corporations. PEC has recently entered into an agreement with the electric membership corporations's GreenCo Solutions, Inc. to jointly pursue swine to energy projects in eastern North Carolina.

PEC is using best efforts to engage the market for swine fueled energy, but technology appears to be less developed than other biomass fuels. PEC continues to monitor the progress of swine to energy technologies and fully intends to secure cost-effective resources to meet compliance requirements as the technologies become viable. Exhibit 7 and Exhibit 8 show PEC's forecasted energy purchases from swine fueled facilities. The costs associated with purchases from swine resources that qualify under the Swine Farm Methane Capture Pilot Program (Senate Bill 1465) will be recovered through the cost recovery provisions specified in that legislation and would not affect the REPS cost recovery rider.

G.S. 62-133.8(f): COMPLIANCE WITH REPS REQUIREMENT THROUGH USE OF POULTRY WASTE RESOURCES

Through the November 2007 renewable RFP responses in conjunction with technology research, PEC has determined that poultry waste resources have a chance of commercial operation by the first REPS requirement in 2012. Based on proposals received through PEC's renewable RFP, most biomass facilities, including poultry waste, must be developed in large blocks of capacity, estimated at 30 MW to 50 MW, to achieve economies of scale and cost effectiveness. PEC is pursuing purchases from poultry waste resources, but does not expect to be able to contract for our prorata share based on the schedule specified in Senate Bill 3. The set aside compliance plan table, included as Exhibit 8, shows PEC's approximate share of the 900,000 MWh total statewide set aside beginning in 2012.

DESCRIPTION OF EXHIBITS

- **A list of executed contracts to purchase renewable energy certificates (whether or not bundled with electric power), including type of renewable energy resource, expected MWh, and contract duration.**

PEC has executed several contracts with renewable energy facilities. These contracts are displayed in Exhibit 1. To provide adequate time for filing preparation, contracts executed as of August 15, 2008 are included in this exhibit.

- **A list of planned or implemented energy efficiency measures, including a brief description of the measure and projected impacts.**

A discussion of existing and planned energy efficiency programs is included in the DSM and EE section of the IRP and Appendix E. Exhibit 2 in this document summarizes the projected energy efficiency MWhs included for REPS compliance.

- **The projected North Carolina retail sales and year-end number of customer accounts by customer class for each year**

Exhibit 3 in this document summarizes the retail sales forecast and corresponding REPS energy requirement. Exhibit 4 summarizes the customer account forecasts and the corresponding REPS cost cap.

- **The current and projected avoided cost rates for each year**

Exhibit 5 summarizes the current and projected avoided cost rates by year. The specific avoided cost assigned to each transaction depends on the deal term and the date the contract is executed.

- **The projected total and incremental costs anticipated to implement the compliance plan for each year**

Exhibit 6 displays the projected total and incremental costs for executed contracts and contracts in negotiation. The costs for undesignated contracts are not forecasted due to the uncertainty regarding the cost of these resources.

- **A comparison of projected costs to the annual cost caps for each year**
- **An estimate of the amount of the REPS rider and the impact on the cost of fuel and fuel-related costs rider necessary to fully recover the projected costs**

Exhibit 6 displays the cost caps and the projected costs for executed contracts and contracts in negotiation. After removing these forecasted costs from the REPS premium, the Exhibit shows the remaining funds projected to be available for undesignated contracts. These future premiums are subject to change due to several factors, including retail growth rate assumptions, underlying cost escalation in executed contracts, change in the energy generation forecast from these resources, amongst others.

Progress Energy - Carolinas

2008 REPS Compliance Filing

Exhibit 1: Executed Contract Summary

Name:	Date Executed:	Resource Type:	Load:	Start Date	End Date	Term:	Capacity MW	Energy MWh	Expected Annual RECs:
Customer A	6/19/2007	Landfill Gas	Baseload	Aug, 2007	Dec 31, 2009	2-yr, 5-mo	4	21,000	21,000
Customer B	7/30/2008	Biomass	Baseload	Oct, 2008*	Dec 31, 2014	6-yr, 3-mo	25	185,405	185,405
Customer C	8/6/2008	Biomass (thermal RECs)	REC Only	Oct, 2008*	Dec 31, 2014	6-yr, 3-mo	0	0	60,000
Customer D	6/20/2008	Solar PV	Energy Only	Dec, 2008*	Dec, 2018	10-yr	1	1,472	1,472
Customer E	8/6/2008	Solar PV	Energy Only	Mar, 2009*	Mar, 2029	20-yr	1	1,472	1,472
Customer F	7/29/2008	Solar PV	Energy Only	Dec, 2008*	Dec, 2028	20-yr	1	1,752	1,752

*Estimated Commercial Operation

Progress Energy - Carolinas

2008 REPS Compliance Filing

Exhibit 2: Energy Efficiency Forecast

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Energy Efficiency Forecast (GWh)	-	6	81	166	275	422	589	753	916	1,071	1,219	1,339	1,442	1,536	1,603	1,665
Maximum Energy Efficiency for REPS Compliance (%)	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	40%	40%	40%
PEC REPS Requirement (GWh)	-	-	8	8	1,196	1,213	1,227	2,480	2,506	2,539	4,285	4,342	4,402	5,582	5,661	5,744
Maximum Energy Efficiency for REPS Compliance (GWh)	-	-	2	2	299	303	307	620	626	635	1,071	1,086	1,101	2,233	2,264	2,298
Net Energy Efficiency for REPS	-	-	2	2	275	303	307	620	626	635	1,071	1,086	1,101	1,536	1,603	1,665

Progress Energy - Carolinas

2008 REPS Compliance Filing

Exhibit 3: Proposed Retail Sales and REPS Compliance

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
PEC REQUIREMENT:																
NC Retail GWh	38,088	38,605	39,168	39,875	40,447	40,898	41,339	41,762	42,311	42,854	43,425	44,022	44,653	45,285	45,955	46,630
REPS Req (%)			0.02%	0.02%	3%	3%	3%	6%	6%	6%	10%	10%	10.0%	12.5%	12.5%	12.5%
REPS Req (GWh)			8	8	1,196	1,213	1,227	2,480	2,506	2,539	4,285	4,342	4,402	5,582	5,661	5,744
Wholesale Requirements:																
Waynesville GWh	103	105	107	108	110	112	114	115	117	119	121	123	125	127	129	131
Tri-Towns GWh [1]	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Total GWh	181	183	184	186	188	190	191	193	195	197	199	201	203	204	206	208
REPS Req (%)			0.02%	0.02%	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
REPS Req (GWh)			0	0	6	6	6	11	12	12	20	20	20	20	20	21
TOTAL REPS REQUIREMENT:	-	-	8	8	1,202	1,219	1,233	2,492	2,517	2,550	4,305	4,362	4,422	5,602	5,681	5,765

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Set Aside Requirements:																
PEC Solar Req %			0.02%	0.02%	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
PEC Solar Req GWh [2]			8	8	28	28	29	58	59	60	86	87	88	90	91	92
State-Wide Swine Waste Req %					0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
PEC Swine Waste Req GWh [2]					28	28	29	58	59	60	86	87	88	90	91	92
State-Wide Poultry Waste Req GWh					170	700	900	900	900	900	900	900	900	900	900	900

Footnote:

(1) Tri-Towns load forecast includes the load for Sharpsburg, Stantonsburg, Black Creek and Lucama.

(2) Requirements are based on combined load for PEC NC Retail and Wholesale.

Progress Energy - Carolinas

2008 REPS Compliance Filing

Exhibit 4: Proposed RPS Cost Cap - North Carolina

Projected Customers [1]

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Est. Number of Res Cust	(000)	1,074	1,092	1,113	1,135	1,158	1,181	1,203	1,225	1,247	1,270	1,294	1,317	1,341	1,365	1,389	1,412
Est. Number of Comm Cust	(000)	181	184	187	191	195	198	201	204	207	210	213	216	219	222	226	229
Est. Number of Ind Cust	(000)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Est. Total Number of Cust	(000)	1,258	1,279	1,303	1,329	1,355	1,381	1,406	1,432	1,457	1,483	1,509	1,536	1,563	1,590	1,617	1,644

Annual Cap by Customer Account

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Residential Annual Cap Per Account	$10	$10	$10	$10	$12	$12	$12	$34	$34	$34	$34	$34	$34	$34	$34	$34
Commercial Annual Cap Per Account	$50	$50	$50	$50	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
Industrial Annual Cap Per Account	$500	$500	$500	$500	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000

Projected Annual Total RPS Cap Amount - PEC

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Residential Class Amount	($ Millions)	**$10.7**	**$10.9**	**$11.1**	**$11.4**	**$13.9**	**$14.2**	**$14.4**	**$41.7**	**$42.4**	**$43.2**	**$44.0**	**$44.8**	**$45.6**	**$46.4**	**$47.2**	**$48.0**
Commercial Class Amount	($ Millions)	**$9.1**	**$9.2**	**$9.4**	**$9.6**	**$29.2**	**$29.6**	**$30.1**	**$30.5**	**$31.0**	**$31.5**	**$31.9**	**$32.4**	**$32.9**	**$33.4**	**$33.9**	**$34.4**
Industrial Class Amount	($ Millions)	**$1.4**	**$1.4**	**$1.4**	**$1.4**	**$2.7**	**$2.7**	**$2.7**	**$2.7**	**$2.7**	**$2.7**	**$2.7**	**$2.7**	**$2.7**	**$2.7**	**$2.7**	**$2.7**
Total Amount from All Customers	($ Millions)	**$21.2**	**$21.5**	**$21.9**	**$22.3**	**$45.8**	**$46.5**	**$47.3**	**$74.9**	**$76.1**	**$77.4**	**$78.6**	**$79.9**	**$81.2**	**$82.5**	**$83.8**	**$85.1**

Footnote:

(1) The number of customer accounts reflect premise billing

Progress Energy - Carolinas

2008 REPS Compliance Filing

Exhibit 5: Current and Projected Avoided Costs

Current Avoided Cost
2006 Filing
Schedule CSP-23B

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total Nominal Avoided Energy Cost	$/MWH	$37.78	$38.95	$41.64	$42.56	$43.30	$44.21	$42.20	$45.44	$44.06	$44.00	$45.43	$49.38	$46.47	$44.88

Projected Avoided Cost [1]

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total Nominal Avoided Energy Cost	$/MWH		$55.36	$54.61	$49.00	$47.55	$46.70	$48.20	$51.30	$52.90	$53.74	$55.93	$52.87	$46.67	$46.21	$49.53	$52.73

Footnote:

(1) The next avoided cost filing will occur later this year. These costs represents a forecast of the avoided cost based on current information and will change with the filing later this year.

Progress Energy - Carolinas

2008 REPS Compliance Filing

Exhibit 6: Projected Total and Incremental Costs

($ millions)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
North Carolina Retail REPS Premium Cap	$ 21.2	$ 21.5	$ 21.9	$ 22.3	$ 45.8	$ 46.5	$ 47.3	$ 74.9	$ 76.1	$ 77.4	$ 78.6	$ 79.9	$ 81.2	$ 82.5	$ 83.8	$ 85.1
Wholesale REPS Premium Cap [1]	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.2	$ 0.2	$ 0.2	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4
Total CAP	$ 21.3	$ 21.6	$ 22.0	$ 22.4	$ 46.0	$ 46.8	$ 47.5	$ 75.3	$ 76.5	$ 77.8	$ 79.0	$ 80.3	$ 81.6	$ 82.9	$ 84.2	$ 85.5
Total Cost of Purchases Excluding Undesignated	$ 1.6	$ 19.6	$ 18.3	$ 18.4	$ 54.7	$ 56.2	$ 57.1	$ 39.0	$ 39.5	$ 39.9	$ 40.4	$ 40.9	$ 41.6	$ 42.1	$ 42.7	$ 43.3
Avoided Cost of Purchases Excluding Undesignated	$ 1.0	$ 10.6	$ 9.6	$ 9.6	$ 29.3	$ 29.3	$ 29.3	$ 20.0	$ 20.0	$ 20.0	$ 20.0	$ 20.0	$ 20.0	$ 20.0	$ 20.0	$ 20.0
REPS PREMIUM EXCLUDING UNDESIGNATED	$ 0.6	$ 8.9	$ 8.6	$ 8.8	$ 25.4	$ 26.9	$ 27.7	$ 19.1	$ 19.5	$ 20.0	$ 20.5	$ 21.0	$ 21.6	$ 22.2	$ 22.8	$ 23.3
R&D and Incremental Expense	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0
TOTAL ($MM)	$ 2.6	$ 10.9	$ 10.6	$ 10.8	$ 27.4	$ 28.9	$ 29.7	$ 21.1	$ 21.5	$ 22.0	$ 22.5	$ 23.0	$ 23.6	$ 24.2	$ 24.8	$ 25.3
REPS Premium Cap	$ 21.3	$ 21.6	$ 22.0	$ 22.4	$ 46.0	$ 46.8	$ 47.5	$ 75.3	$ 76.5	$ 77.8	$ 79.0	$ 80.3	$ 81.6	$ 82.9	$ 84.2	$ 85.5
Available Premium for Undesignated	$ 18.7	$ 10.7	$ 11.4	$ 11.6	$ 18.6	$ 17.9	$ 17.8	$ 54.2	$ 55.0	$ 55.8	$ 56.6	$ 57.3	$ 58.0	$ 58.7	$ 59.5	$ 60.2

Footnotes:

(1) Premium based on assumption of 0.5% of Progress Energy North Carolina retail load

Progress Energy - Carolinas

2008 REPS Compliance Filing

Exhibit 7: REPS Compliance

REPS REQUIREMENT	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
North Carolina Retail (GWh)	38,088	38,605	39,168	39,875	40,447	40,898	41,339	41,762	42,311	42,854	43,425	44,022	44,653	45,285	45,955	46,630
Wholesale (GWh) [1]	181	183	184	186	188	190	191	193	195	197	199	201	203	204	206	208
REPS Requirement (GWh)	-	-	8	8	1,202	1,219	1,233	2,492	2,517	2,550	4,305	4,362	4,422	5,602	5,681	5,765
ENERGY EFFICIENCY (GWh) [2]	-	-	2	2	275	303	307	620	626	635	1,071	1,086	1,101	1,536	1,603	1,665
PEC OWNED GENERATION (GWh)																
PEC Hydro Generation	487	600	599	599	599	599	599	599	599	599	599	599	599	599	599	599
CONTRACTED PURCHASES (GWh)																
Solar Generation	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Biomass Generation	26	211	185	185	185	185	185	-	-	-	-	-	-	-	-	-
PROJECTED RESOURCES (GWh) [3]																
Poultry Generation	-	-	-	-	315	315	315	315	315	315	315	315	315	315	315	315
Undesignated Solar Generation	-	7	8	8	8	19	24	53	54	55	81	83	84	85	86	88
Undesignated Swine Generation	-	-	-	-	28	28	29	58	59	60	86	87	88	90	91	92
Undesignated Other Generation [4]	-	13	13	13	13	13	13	385	385	385	385	1,700	2,230	2,972	2,982	3,001
TOTAL SUPPLY RESOURCES (GWh)	513	835	812	812	1,428	1,468	1,477	2,036	2,044	2,053	2,543	3,874	4,422	5,602	5,681	5,765
REPS Requirement (GWh)	-	-	8	8	1,202	1,219	1,233	2,492	2,517	2,550	4,305	4,362	4,422	5,602	5,681	5,765
SUPPLY RESOURCES RELATIVE TO REQ. (GWh)	513	835	804	804	226	249	244	(456)	(474)	(497)	(1,762)	(488)	-	-	-	-
REC BANKING																
Beginning REC Carryforward Balance (000)	-	513	1,348	2,152	2,956	3,182	3,431	3,676	3,220	2,747	2,250	488	-	-	-	-
RECs Added (Used) (000)	513	835	804	804	226	249	244	(456)	(474)	(497)	(1,762)	(488)	-	-	-	-
Ending REC Carryforward Balance (000)	513	1,348	2,152	2,956	3,182	3,431	3,676	3,220	2,747	2,250	488	-	-	-	-	-
Net Supply Relative to Req. After REC Carryover (GWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Footnotes:

(1) Represents the requirement of wholesale customers that have agreed to have Progress Energy comply on their behalf and have contributed REPS premium dollars for this requirement

(2) Energy Efficiency forecast reflects the limit of 25% of REPS compliance through 2020 and 40% afterwards.

(3) The undesignated generation is the amount required to meet the MWh requirement. The MWh shown may decrease due to $/customer cap limitations depending on the price of these resources

(4) The undesignated other generation includes potential REC only purchases for compliance (no associated generation)

Progress Energy - Carolinas

2008 RPS Compliance Filing

Exhibit 8: Set Asides

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
PEC Solar Energy Requirement (GWh)	-	-	8	8	28	28	29	58	59	60	86	87	88	90	91	92
PEC Swine Waste Energy Requirement (GWh)	-	-	-	-	28	28	29	58	59	60	86	87	88	90	91	92
State-Wide Poultry Waste Energy Requirement (GWh)	-	-	-	-	170	700	900	900	900	900	900	900	900	900	900	900
Solar Purchase Summary (GWh)																
Solar Energy Requirement [1]	-	-	7.8	7.9	28.0	28.4	28.8	58.1	58.7	59.5	86.1	87.2	88.4	89.7	91.0	92.3
Contracted Solar	-	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Projected Solar	-	6.6	7.7	7.7	7.7	18.8	24.1	53.4	54.0	54.8	81.4	82.6	83.8	85.0	86.3	87.6
Total Solar Resources	-	11.3	12.4	12.4	12.4	23.5	28.8	58.1	58.7	59.5	86.1	87.2	88.4	89.7	91.0	92.3
Solar Resources Relative to Requirement	-	11.3	4.7	4.6	(15.6)	(4.9)	-	-	-	-	-	-	-	-	-	-
Beginning Solar REC Bank	-	-	11.3	16.0	20.6	4.9	-	-	-	-	-	-	-	-	-	-
Ending Solar REC Bank	-	11.3	16.0	20.6	4.9	-	-	-	-	-	-	-	-	-	-	-
Swine Purchase Summary (GWh):																
Swine Waste Energy Requirement [1]	-	-	-	-	28.0	28.4	28.8	58.1	58.7	59.5	86.1	87.2	88.4	89.7	91.0	92.3
Contracted Swine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Projected Swine	-	-	-	-	28.0	28.4	28.8	58.1	58.7	59.5	86.1	87.2	88.4	89.7	91.0	92.3
Total:	-	-	-	-	28.0	28.4	28.8	58.1	58.7	59.5	86.1	87.2	88.4	89.7	91.0	92.3
Swine Resources Relative to Requirement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Poultry Waste Purchase Summary (GWh):																
Poultry Waste Energy State-Wide Requirement	-	-	-	-	170.0	700.0	900.0	900.0	900.0	900.0	900.0	900.0	900.0	900.0	900.0	900.0
Contracted Poultry	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Projected Poultry	-	-	-	-	315.4	315.4	315.4	315.4	315.4	315.4	315.4	315.4	315.4	315.4	315.4	315.4
Poultry Resources Relative to State-Wide Requirement	-	-	-	-	145.4	(384.6)	(584.6)	(584.6)	(584.6)	(584.6)	(584.6)	(584.6)	(584.6)	(584.6)	(584.6)	(584.6)
Poultry Resources Percent of Total Requirement	0%	0%	0%	0%	186%	45%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%

Footnotes:

(1) Requirements are based on combined load for PEC NC Retail and Wholesale.

Progress Energy

Progress Energy Carolinas Integrated Resource Plan

Appendix E
DSM & Energy Efficiency

September 1, 2008

Demand Side Management (DSM) and Energy Efficiency (EE) Programs

Progress Energy Carolinas, Inc. (PEC) has a number of energy efficiency and demand side management programs in place. These programs are available in both North and South Carolina. These include the following:

Existing Energy Efficiency Programs

On Line Account Access

Energy analysis graphs allow customers to compare their electric usage in the current and previous year to the average temperature by month; compare past 12 months electric usage to the high, low, and average temperature for the same period; and compare average monthly temperatures for the past 24 months. The energy analysis details allow customers to view their past 24 months of electric usage including the date the bill was mailed; number of days in the billing cycle; kWh (kilowatt hour) usage per month; daily kWh usage; average, low, and high temperature for the month; and click on a month and get daily temperature information for the month. These tools assist customers with understanding their energy usage patterns and identifying opportunities to reduce energy consumption. This program was initiated in 1999.

"Lower My Bill" Toolkit

This tool, implemented in 2004, provides on-line tips and specific steps to help customers determine actions to reduce energy consumption and lower utility bills. The suggestions range from relatively simple no-cost steps to more extensive actions involving insulation and heating and cooling equipment, as well as payment options.

Energy Saving Tips

PEC has been providing tips on how to reduce home energy costs since approximately 1981. This information is now available on-line. The site includes information on the typical biggest household energy wasters and how a few simple actions can increase efficiency. Topics include: Energy Efficient Heat Pumps, Mold, Insulation R-Values, Air Conditioning, Appliances and Pools, Attics and Roofing, Building/Additions, Ceiling Fans, Ducts, Fireplaces, Heating, Hot Water, Humidistats, Landscaping, Seasonal Tips, Solar Film, and Thermostats.

Home Energy Check (Mail-In)

PEC's Home Energy Check, implemented in 2002, is a comprehensive residential energy evaluation program designed to help customers identify the best ways to save energy in their home and find the resources to achieve those savings. The program provides customers with an analysis of energy consumption and recommendations on energy efficiency improvements. The

Home Energy Check helps customers identify and evaluate cost-effective energy-saving measures for their homes.

Online Home Energy Check

This Web-based energy check, begun in 2002, enables customers to quickly answer common questions regarding energy usage and provides a full range of personalized recommendations for managing home energy costs. Customers receive specific recommendations for their household with detailed approaches for better managing energy use and saving money. The analysis also includes an automatic download of the customer's actual electric bill history.

Energy Efficient Home Program

PEC introduced in the early 1980's the Energy Efficient Home program. This program provides residential customers with a 5% discount of the energy and demand portions of their electricity bills when their homes met certain thermal efficiency standards that were significantly above the existing building codes and standards. Through December 2007, over 280,676 dwellings system wide qualify for the discount.

Currently, PEC utilizes the Energy Star standard for new applications for the energy conservation discount. Energy Star is the national symbol for energy efficiency. It is a partnership between the DOE, the U.S. Environmental Protection Agency (EPA), local utilities, product manufacturers, and retailers. Homes built with this label are at least 15% more efficient than the national Model Energy Code, have greater value, lower operating costs, increased durability, comfort, and safety. Features of an Energy Star Home include:

- Improved Insulation
- Advanced Windows
- Tightly-sealed Ducts
- High-Efficiency Heating and Cooling
- Reduced Air Infiltration

Homes that pass an Energy Star test receive a certificate as well as a 5% discount on energy and demand portions of their electricity bills. Builders receive training in building energy efficient homes and a means of differentiating their product on the market place.

Contractor Training

PEC began sponsoring training in 2000 for home builders on Energy Star® standards in order to promote more energy efficient building practices, and has provided this training to more than two thousand participants system wide since 2000. Energy Star® certified homes qualify for PEC's 5% energy conservation discount. PEC also sponsors training for heating, ventilation, and

air conditioning (HVAC) contractors on sizing and proper installation of energy efficient HVAC systems. Properly sized and installed HVAC systems utilize less energy and provide increased home comfort.

Energy Efficiency Financing

PEC began offering energy efficiency financing with its "Home Energy Loan Program" in 1981. In 2002 PEC contracted with an outside vendor to provide financing with rates set by Fannie Mae. More than 500 loans system wide have been made since that time. This program connects customers with screened contractors who provide complete installation and financing on a range of energy-saving home improvements.

Energy Resource Center

In 2000, PEC began offering its large commercial, industrial, and governmental customers a wide array of tools and resources to use in managing their energy usage and reducing their electrical demand and overall energy costs. Through its Energy Resource Center, located on the PEC Web site, PEC provides newsletters, online tools and information which cover energy efficiency topics such as:

- Electric chiller operation
- Lighting system efficiency
- Compressed air systems
- Motor management
- Variable speed drives
- How to conduct an energy audit

Also located on the Energy Resource Center website is PEC's Energy Profiler Online tool. Through this service, customers can analyze their electrical usage to gain an in-depth understanding of when and how they are using electrical energy. This detailed data is essential for identifying potential energy savings opportunities.

CIG Account Management

All PEC commercial, industrial, and governmental customers with an electrical demand greater than 200 kW (approximately 4800 customers) are assigned to a PEC Account Executive (AE). The AEs work hand-in-hand with their assigned customers to help them manage their energy usage and costs and to assist them in developing energy efficiency solutions. The AEs go onsite with the customer to better understand their customer's business operation and energy needs. The AEs personally assist customers in conducting an energy analysis of their facility and can bring in the resources of the Advanced Energy Corporation or the N.C. State Industrial Extension Service when a very detailed and in depth analysis of a specific energy system is required. The AEs provide informational and educational opportunities to help ensure the customers are aware of the latest energy improvement and system operational techniques.

Existing Demand Response (DR) Programs

Time-of-Use Rates

PEC has offered voluntary Time-of-Use (TOU) rates to all customers since 1981. These rates provide incentives to customers to shift consumption of electricity to lower-cost off-peak periods and lower their electric bill.

Thermal Energy Storage Rates

PEC began offering thermal energy storage rates in 1979. The present General Service (Thermal Energy Storage) rate schedule uses 2-period pricing with seasonal demand and energy rates applicable to thermal storage space conditioning equipment. Summer on-peak hours are noon to 8 p.m. and non-summer hours of 6 a.m. to 1 p.m. weekdays.

Real-Time Pricing

PEC's Large General Service (Experimental) Real Time Pricing tariff was implemented in 1998. This tariff uses a two-part real time pricing rate design with baseline load representative of historic usage. Hourly rates are provided on the prior business day. A minimum of 1 MW load is required. This rate schedule is presently fully subscribed.

Curtailable Rates

PEC began offering its curtailable rate options in the late 1970s, and presently offers two tariffs whereby industrial and commercial customers receive credits for PEC's ability to curtail system load during times of high energy costs and/or capacity constrained periods.

Voltage Control

This procedure involves reducing distribution voltage during periods of capacity constraints, representing a potential system reduction of 78 MW. This level of reduction does not adversely impact customer equipment or operations.

Summary of Available Demand-Side and Energy Efficiency Programs

The following table provides information on PEC's demand-side and energy efficiency programs available at the time of this report. This information, where applicable, includes program type, capacity, energy, number of customers enrolled in program, and activations since December, 2007. While the energy savings impacts of PEC's programs are embedded within its load and energy forecasts, the specific energy impacts from PEC's Compact Fluorescent Lamp (CFL) Buy-Down Pilot Program are available as a result of its 2008 third party evaluation.

Program Description	Type	Capacity (MW)	Annual Energy (MWH)	Participants	Activations Since 12/07
Energy Efficiency Programs[1]	EE	520	NA	NA	NA
Large Load Curtailment	DSM	319	NA	78	0
Real Time Pricing (RTP)[1]	DSM	55	NA	100	NA
Commercial & Industrial TOU[1]	DSM	5	NA	21,683	NA
Residential TOU[1]	DSM	12	NA	28,836	NA
2007 CFL Buy-Down Pilot[1]	EE	0.7	6,934	NA	NA
Voltage Control	DSM	78	NA	NA	0

Since PEC's last resource plan report, in December 2007, 2.5% voltage reduction has been implemented for contingencies and testing, but not peak load reduction. The implementation history is shown below. There have been no Large Load Curtailment implementations.

StartTime	EndTime	Duration (Minutes)
8/14/2008 13:04	8/14/2008 19:02	358
8/12/2008 13:00	8/12/2008 19:01	361
8/8/2008 13:00	8/8/2008 19:01	361
7/24/2008 13:00	7/24/2008 19:05	365
7/23/2008 12:59	7/23/2008 15:17	138
7/22/2008 10:36	7/22/2008 10:41	5
6/28/2008 18:37	6/28/2008 18:50	13
6/26/2008 17:33	6/26/2008 18:00	27
4/10/2008 9:07	4/10/2008 11:18	131
4/3/2008 9:00	4/3/2008 11:00	120
3/7/2008 18:31	3/7/2008 18:57	26
2/27/2008 11:20	2/27/2008 11:30	10
2/19/2008 21:58	2/19/2008 22:23	25
2/12/2008 5:59	2/12/2008 8:01	122
2/11/2008 18:59	2/11/2008 21:00	121
2/8/2008 6:54	2/8/2008 7:02	8
2/6/2008 6:01	2/6/2008 8:01	120
1/31/2008 18:59	1/31/2008 21:00	121
1/31/2008 5:59	1/31/2008 8:00	121
1/30/2008 18:57	1/30/2008 21:00	123

PEC has not discontinued any of its demand-side resource programs since its previous resource plan submission.

[1] These program impacts are embedded within the load and energy forecast.

Proposed DSM and EE Programs

In 2007, PEC announced a commitment to defer 1,000 MW of power generation requirements over the next 10 years through DSM and EE programs. This commitment is part of PEC's long-term, balanced energy strategy to meet the future energy needs of its customers. This balanced energy strategy includes a strong commitment to DSM and EE programs, investments in renewable and emerging energy technologies, and state-of-the art power plants and delivery systems. On April 29, 2008, PEC filed for the approval of two DSM programs: Distribution System Demand Response (DSDR) Program and Residential EnergyWise™. On May 1, 2008, PEC filed three EE programs. These were the Residential Home Advantage New Construction Program, the Commercial, Industrial, and Governmental (CIG) New Construction Program and the CIG Comprehensive Retrofit Program. PEC plans to offer these programs in the future in South Carolina.

Summary of Pending Programs

The following tables provide PEC's estimates of annualized capacity reductions, energy reductions, and customer participation for its filed programs over the near term. It is important to note that the program's launch date, forecasted levels of savings and participation levels will likely be influenced by both the timing between the filing date and the NC Commission's decision and the ultimate terms contained in the NC Commission's decision.

Expected Summer Peak Demand Reduction (MW)

	DSDR	EnergyWise	CIG New Construction	CIG Retrofit	Res New Construction
2009	29	10	0	0	0
2010	101	35	0	1	1
2011	174	70	1	3	2
2012	247	105	2	5	5
2013	251	145	3	8	9

Expected Energy Reductions (MWH)

	DSDR	EnergyWise[2]	CIG New Construction	CIG Retrofit	Res New Construction
2009	22,211	115	345	505	774
2010	38,956	388	1,724	5,558	3,626
2011	57,389	770	3,966	12,885	8,189
2012	76,443	1,168	7,415	23,244	17,316
2013	76,210	1,610	11,726	35,877	31,006

[2] EnergyWise™ energy savings are based upon five summer load control events and four winter load control events.

Projected Customer Acceptance
(Percentage of Eligible Market)

	DSDR	EnergyWise A/C	EnergyWise Heating	EnergyWise Water Heat	Res New Construction	CIG New Construction	CIG Retrofit
2009	NA	1.1%	1.8%	2.3%	6%	4%	0.1%
2010	NA	4.6%	5.3%	8.3%	5%	14%	0.5%
2011	NA	7.9%	8.7%	14.1%	8%	22%	0.7%
2012	NA	11.1%	11.9%	19.7%	16%	34%	1.0%
2013	NA	14.2%	15.0%	25.0%	24%	42%	1.3%

DSM and EE Forecasts

The tables below show the composite impacts estimated for new DR, EE, and DSDR. The tables do not include savings from existing Large Load Curtailment or VR programs. The total savings below exceed the total savings reflected in the pending program tables above because the tables below include both new programs being added and existing program growth.

Incremental Summer Peak MW Demand Savings @ Gen

	Residential		Non-Residential		Total		Total		Total
Year	DR	EE	DR	EE	DR	EE	DR & EE	DSDR	Savings
2008	0	0	0	0	0	0	0	7	7
2009	10	1	2	1	12	2	14	29	43
2010	35	7	8	16	43	23	66	101	167
2011	70	14	14	33	84	47	131	174	305
2012	105	25	22	53	127	78	205	247	452
2013	145	42	34	79	179	121	300	251	551
2014	180	65	49	106	229	171	400	257	657
2015	213	91	63	130	276	221	497	260	757
2016	238	118	75	154	313	272	585	265	850
2017	255	144	88	176	343	320	663	271	933
2018	265	170	99	196	364	366	730	274	1,003
2019	268	191	104	212	372	403	775	279	1,054
2020	265	210	104	226	369	436	805	282	1,087
2021	262	226	104	239	366	465	831	290	1,122
2022	260	239	104	247	364	486	850	296	1,146
2023	257	249	104	256	361	505	866	299	1,165

Incremental Winter Peak MW Demand Savings @ Gen									
	Residential		Non-Residential		Total		Total		Total
Year	DR	EE	DR	EE	DR	EE	DR & EE	DSDR	Savings
2008	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	1	1	7	8
2010	2	3	0	6	3	9	12	29	41
2011	6	8	1	18	7	26	33	101	135
2012	12	15	2	32	14	47	61	174	235
2013	18	25	2	50	21	75	95	247	342
2014	25	40	4	69	29	110	138	251	389
2015	25	59	5	89	30	147	178	257	434
2016	26	78	6	107	32	185	217	260	476
2017	29	98	7	124	36	222	258	265	523
2018	31	118	8	140	39	257	296	271	567
2019	32	135	9	153	41	288	330	274	603
2020	33	150	9	164	42	315	356	279	635
2021	32	163	9	174	41	338	379	282	661
2022	32	175	9	182	41	357	398	290	688
2023	32	183	9	189	41	372	413	296	709

Incremental Annual MWh Energy Savings @ Gen									
	Residential		Non-Residential		Total		Total		Total
Year	DR	EE	DR	EE	DR	EE	DR & EE	DSDR	Savings
2008	0	0	0	0	0	0	0	9,195	9,195
2009	115	2,102	24	3,942	140	6,044	6,184	22,211	28,396
2010	388	18,133	87	63,072	474	81,205	81,679	38,956	120,635
2011	770	36,004	152	130,086	922	166,090	167,012	57,389	224,401
2012	1,168	65,700	239	208,926	1,407	274,626	276,033	76,443	352,476
2013	1,610	110,376	367	311,418	1,977	421,794	423,771	76,210	499,981
2014	1,993	171,464	525	417,852	2,518	589,316	591,834	76,331	668,165
2015	2,312	240,140	673	512,460	2,985	752,600	755,585	76,422	832,007
2016	2,567	308,875	802	607,068	3,369	915,943	919,312	76,823	996,135
2017	2,755	377,611	939	693,792	3,693	1,071,403	1,075,096	76,934	1,152,030
2018	2,866	446,287	1,052	772,632	3,918	1,218,919	1,222,837	77,601	1,300,438
2019	2,898	502,960	1,105	835,704	4,002	1,338,664	1,342,666	78,788	1,421,454
2020	2,873	550,927	1,107	890,892	3,980	1,441,819	1,445,799	78,784	1,524,583
2021	2,844	593,987	1,107	942,138	3,951	1,536,125	1,540,076	78,989	1,619,066
2022	2,816	629,130	1,107	973,674	3,923	1,602,804	1,606,727	78,924	1,685,651
2023	2,788	655,568	1,107	1,009,152	3,895	1,664,720	1,668,614	78,991	1,747,605

Further explanations of the proposed programs are as follows:

Distribution System Demand Response Program (DSDR)
Reference: NCUC Docket No. E-2, Sub 926

A few electric utilities in the industry have been using a technique called conservation voltage reduction (CVR) over the past decade to reduce peak demand by lowering system voltage. PEC has utilized CVR during certain conditions such as when additional megawatts are required for short time periods to meet system contingencies and operating requirements. This practice is used in a limited fashion because under current system design criteria, some customers could experience voltages below the lowest allowable level. The DSDR Program will provide the ability to reduce peak demand for 4 to 6 hours at a time, which is the duration consistent with typical peak load periods, which would otherwise require building peaking generation capacity and customer delivery voltage will be maintained above the minimum requirement when the program is in use. This capability will be accomplished by investing in a robust system of advanced technology, telecommunications, equipment, and operating controls. The DSDR Program will help PEC implement a least cost mix of demand reduction and generation measures that meet the electricity needs of its customers.

Residential EnergyWise™ Program
Reference: NCUC Docket No. E-2, Sub 927

The Residential EnergyWise™ Program is a direct load control program that will allow PEC, through the installation of load control switches at the customer's premise, to remotely control the following residential appliances.

- Central air conditioning or electric heat pumps
- Auxiliary strip heat on central electric heat pumps (Western Region only)
- Electric water heaters (Western Region only)

For each of the control options above, an initial one-time bill credit of $25 following the successful installation and testing of load control device(s) and an annual bill credit of $25 will be provided to program participants in exchange for allowing PEC to control the listed appliances.

The program will provide PEC with the ability to reduce and shift peak loads, thereby reducing its system peak demands and providing for a corresponding deferral of new supply-side peaking generation and enhancing system reliability. Participating customers will be impacted by (1) the installation of load control equipment at their residence, (2) load control events which will curtail the operation of their air conditioning, heat pump strip heating or water heating unit for a period of time each hour, and (3) the receipt of an annual bill credit from PEC in exchange for allowing PEC to control their electric equipment. PEC's retail customers as a whole will benefit over the program horizon as the cost savings from the deferral of supply-side peaking generation surpass program costs.

Home Advantage New Construction Program
Reference: NCUC Docket No. E-2, Sub 928

Under the Home Advantage New Construction Program, PEC offers developers and builders the potential to maximize energy savings in various types of new residential construction. The program will utilize a prescriptive approach for developers and builders of projects for single-family, multi-family (three stories or less), and manufactured housing units. The program will also be available to high rise multi-family units that are currently not eligible for Energy Star as long as each unit meets the intent of the Energy Star builder option package for their climate zone and the Home Advantage Program criteria.

The primary objective of this program is to reduce the system seasonal peak and reduce the consumption of electricity by new homes. PEC's service territory is experiencing and will continue to experience a high level of new construction activity by various residential segments. The residential segments are adding approximately 25,000 new housing units each year. New construction represents a tremendous opportunity for capturing cost effective DSM and EE savings because only the incremental cost of upgrading the design is evaluated. It is imperative that these opportunities be identified and addressed as early as possible so that PEC can influence the decision makers such as the developers and builders of apartments, condos, and other new housing such as single-family, multi-family, and manufactured housing located in the PEC service territory.

Commercial, Industrial, and Governmental (CIG) New Construction Program
Reference: NCUC Docket No. E-2, Sub 928

PEC's service territory is continually experiencing and will continue to experience a high level of robust new construction activity by certain CIG segments. New Construction represents a tremendous opportunity for capturing cost effective DSM and EE savings because only the incremental cost of upgrading the design is evaluated. It is imperative that these opportunities be identified and addressed as early in the design phase as possible to influence the design to a higher efficiency level.

CIG New Construction Program offers its customers the potential to maximize energy savings in various types of new building construction. Through this program, the customers' existing architect/engineering team partners with PEC and its pre-qualified energy efficiency engineering firm to develop comprehensive, cost-effective, energy conservation measures that exceed a pre-determined base case design. This service is reserved for new CIG construction or extensive renovation where the benefits gained from a comprehensive, integrated design effort will reap incremental savings by reducing the building's annual energy use and cost.

The primary objective of this program is to reduce electrical energy consumption and peak demand within the CIG market segment by working closely with customers and trade allies to design and build energy-efficient facilities for the future. The program seeks to meet the following overall goals:

- Influence and work closely with design firms to expand energy-efficient building design practices and create a future supply of energy-efficient facilities.
- Educate CIG customers regarding the benefits of energy-efficient design and provide them with tools and resources to cost-effectively implement energy-saving projects.
- Obtain energy and demand impacts that are significant, reliable, sustainable and measurable.
- Implement cost-effective measures for the marketplace.

Commercial, Industrial, and Governmental (CIG) Comprehensive Retrofit Program
Reference: NCUC Docket No. E-2, Sub 928

PEC's service territory contains a large number of CIG type customers with older, energy inefficient electrical equipment. These customers represent a significant opportunity for electrical energy savings. For example, governmental customers are often under-funded and need assistance in identifying and retrofitting older facilities with new high efficiency electrical equipment.

The program is targeted to PEC's largest CIG customers with demands greater than 200 kW. PEC will partner with pre-qualified energy efficiency engineering firms to identify, evaluate, and present electrical energy conservation measures to its customers. PEC will pre-qualify energy efficiency engineering firms and installation contractors for various implementation services such as lighting to ensure work is performed by qualified firms at cost effective prices.

The primary objective of this program is to reduce electrical energy consumption and peak demand within the CIG market segment by working closely with customers and trade allies to upgrade existing buildings to energy-efficient facilities for the future. The program seeks to meet the following overall goals:

- Influence and work closely with design firms to expand energy-efficient building design practices and create a future supply of energy-efficient facilities.
- Educate CIG customers regarding the benefits of energy-efficient design and provide them with tools and resources to cost-effectively implement energy-saving projects.
- Obtain energy and demand impacts that are significant, reliable, sustainable and measurable.
- Implement cost-effective measures for the marketplace.

Summary of Prospective Program Opportunities

In addition to the PEC programs pending before the NC Commission, additional programs are contemplated for implementation within the next two years. These programs will cover: (1) residential home energy improvements; (2) residential home energy information and audits (3) targeted low income energy efficiency assistance; (4) commercial energy efficiency measures; (5) CIG demand response initiatives; (6) CIG education and awareness initiatives; (7) research and development; and (8) alternative energy initiatives.

Rejected Demand Side Management and Energy Efficiency Programs

PEC has not rejected any evaluated energy efficiency or demand side management resources since the last Resource Plan filing.

Current and Anticipated Consumer Education Programs

Several of PEC's previously listed energy-efficiency programs can be classified as being or containing educational measures. These programs include:

- On Line Account Access
- "Lower My Bill" Toolkit
- Energy Saving Tips
- Home Energy Check (Mail-In)
- Online Home Energy Check
- Energy Efficient Home Program
- Contractor Training
- Energy Resource Center
- CIG Account Management

In addition to these currently available measures, PEC is in the process of expanding its education-focused programs. These expanded offerings include the "Save the Watts" program along with other programs focused on providing energy education benefits to PEC's retail customer base.

In 2007, Progress Energy Carolinas launched "Save the Watts", a customer education and engagement campaign. The program is primarily targeted to PEC's residential customers.

The "Save the Watts" campaign was designed to build awareness and participation in the energy-efficiency and demand-side management programs offered by PEC. Its goal is to help customers understand not only how to use energy wisely, but to also provide them with specific tools and tips to help them save energy and money. "Save the Watts" campaign messages have been aggressively promoted via TV, radio, and print advertising, bill inserts, and earned media opportunities.

Another strong component of the campaign is its customized, interactive Web site, ***www.savethewatts.com***. Here, customers can find energy-efficiency tips, information about PEC's savings programs, calculators to help identify potential savings, and a link to a free Online Home Energy Check.

Progress Energy Carolinas is also a partner in a proposal for North Carolina's first-ever Wind for Schools program in Madison County. This program, developed by the Department of Energy (DOE) and currently implemented in five states, sets the framework for a group of state partners to install small wind turbines at rural schools. The intent of the program, as defined by DOE, is to provide students and teachers with a physical example of how communities can take part in

providing for the economic and environmental security of the nation while allowing exciting, hands-on educational opportunities. The partners are currently awaiting word on whether the federal grant application will be approved. If approved, PEC will support implementation and promotion of the Madison County project and would support the program's expansion.

PEC has not discontinued any of its educational programs since its last report filed with the Commission.

Progress Energy

Progress Energy Carolinas Integrated Resource Plan

Appendix F
Air Quality and Climate Change

September 1, 2008

Air Quality Legislative and Regulatory Issues

Progress Energy Carolinas (PEC) is subject to various federal and state environmental compliance laws and regulations that require reductions in air emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), and mercury. PEC is installing control equipment pursuant to the provisions of the NOx SIP Call, the North Carolina Clean Smokestacks Act, the Clean Air Interstate Rule (CAIR), the Clean Air Visibility Rule (CAVR) and mercury regulation, which are discussed below.

NOx SIP Call

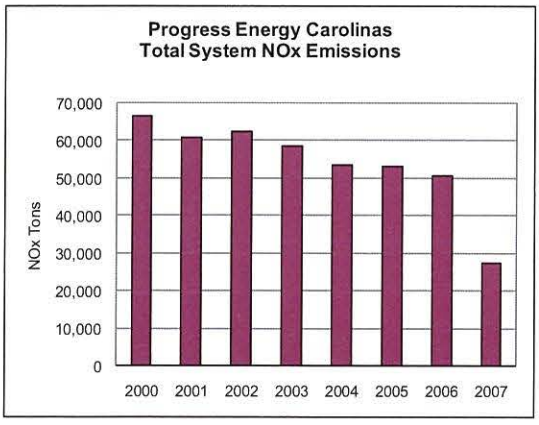
The EPA finalized the NOx State Implementation Plan (SIP) Call in October 1998. The NOx SIP Call requires reductions in NOx emissions from power plants and other large combustion sources in 21 eastern states. The regulation is designed to reduce interstate transport of NOx emissions that contribute to non-attainment for ground-level ozone. As a result, PEC has installed NOx controls on many of its units.

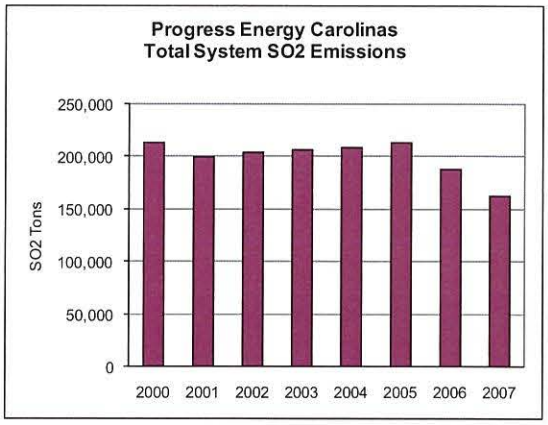
North Carolina Clean Smokestacks Act

In June 2002, the North Carolina Clean Smokestacks Act was enacted, requiring the state's electric utilities to reduce NOx and SO_2 emissions from their North Carolina coal-fired power plants in phases by 2013. PEC owns and operates approximately 5,000 MW of coal-fired generation capacity in North Carolina that is affected by the Clean Smokestacks Act.

As a result of compliance with the Clean Smokestacks Act and the NOx SIP Call, PEC will significantly reduce SO_2 and NOx emissions from its NC coal-fired units. By 2013, PEC projects SO_2 emissions will be reduced by approximately 80% and NOx emissions will be reduced by approximately 70% from their year 2000 levels.

The following charts show PEC's total system annual SO_2 and NOx emissions history from 2000 through 2007.





Clean Air Interstate Rule (CAIR)

On March 10, 2005, the EPA issued the final CAIR, which required the District of Columbia and 28 states, including North and South Carolina, to reduce NOx and SO_2 emissions in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2. States were required to adopt rules implementing the CAIR. The EPA approved both the North and South Carolina CAIR in 2007.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) vacated the CAIR in its entirety. The Court will not issue its mandate for at least 45 days following the date of the decision, pending whether petitions for rehearing are submitted and granted. This development will not significantly affect PEC's compliance plans for its North Carolina facilities given the Clean Smokestacks Act requirements. An exception is that the installation of NOx controls at PEC's Sutton Unit 3 may now need to be accelerated for the Clean Air Visibility Rule.

Clean Air Visibility Rule (CAVR)

On June 15, 2005, the EPA issued the final CAVR. The EPA's rule requires states to identify facilities, including power plants, built between August 1962 and August 1977 with the potential to produce emissions that affect visibility in 156 specially protected areas, including national parks and wilderness areas. To help restore visibility in those areas, states must require the identified facilities to install Best Available Retrofit Technology (BART) to control their emissions. PEC's BART eligible units are Asheville Units No. 1 and No. 2, Roxboro Units No. 1, No. 2 and No. 3, and Sutton Unit No. 3. PEC's compliance plan to meet the NC Clean Smokestacks Act requirements is expected to fulfill the majority of BART requirements; an exception is the installation of NOx controls at PEC's Sutton Unit 3 may now need to be accelerated.

Clean Air Mercury Rule (CAMR)

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 both the delisting determination and the CAMR. It is uncertain how the decision that vacated the federal CAMR will affect 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 it requires compliance plan applications to be submitted in 2013.

National Ambient Air Quality Standards (NAAQS)

On March 12, 2008, the EPA announced changes to the NAAQS for ground-level ozone. The EPA revised the 8-hour primary and secondary standards from 0.08 parts per million to 0.075 parts per million. The air quality improvements expected over the next several years, as steps are

taken to meet current requirements (e.g., the NC Clean Smokestacks Act), will determine whether additional non-attainment areas are designated in PEC's service territories. Should additional non-attainment areas be designated in PEC's service territories, PEC may be required to install additional emission controls at some facilities.

On May 20, 2008, the EPA proposed a revision to the NAAQS for lead to a level in the 0.10 to 0.30 micrograms per cubic meter range. The current standard is 1.5 micrograms per cubic meter, calendar quarter average. The proposed revision is not expected to have a material impact on PEC's operations.

Global Climate Change

PEC has articulated principles that we believe should be incorporated into any global climate change policy. In addition to a report issued in 2006, Progress Energy issued an updated report on global climate change in 2008, which further evaluates this dynamic issue. While we participate in the development of a national climate change policy framework, we will continue to actively engage others in our region to develop consensus-based solutions, as we did with the NC Clean Smokestacks Act. In North Carolina, PEC is a member of the Legislative Commission on Global Climate Change, which is developing recommendations on how the state should address the issue. In South Carolina, PEC is a member of the Governor's Climate, Energy, and Commerce Committee, which released recommendations on how the state should address the issue in August 2008.

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 July 11, 2008, the EPA issued an Advance Notice of Proposed Rulemaking inviting public comment on the issues and options that should be considered in development of comprehensive greenhouse gas regulation under the Clean Air Act.

Progress Energy

Progress Energy Carolinas Integrated Resource Plan

Appendix G
Transmission & NC Rule R8-62

September 1, 2008

This appendix lists transmission line and substation additions, and a discussion of the adequacy of PEC's transmission system. This appendix also provides information pursuant to the North Carolina Utility Commission Rule R8-62.

PEC Transmission Line Additions

	LOCATION				
YEAR	FROM	TO	CAPACITY MVA	VOLTAGE KV	COMMENTS
2008	Trenton Road Tap	Trenton Road	403	230	New
2009	Wadesboro Bowman School Tap	Wadesboro Bowman School	628	230	New
2010	Clinton	Lee Sub	628	230	New
2011	Harris	RTP Switching Sta.	1195	230	New
	Rockingham	West End East	1195	230	New
	Richmond	Fort Bragg Woodruff Street	1195	230	New
	Asheboro	Pleasant Garden (Duke)	1195	230	New
	Rockingham	Lilesville South	1195	230	New
2013	Greenville	Kinston DuPont	628	230	New
2017	Cape Fear Plant	Siler City	628	230	New

PEC Substation Additions

YEAR	SUBSTATION NAME	COUNTY	STATE	VOLTAGE (KV)	MVA	COMMENTS
2009	Florence	Florence	SC	230/115	600	Uprate
	Jacksonville	Onslow	NC	230/115	600	Modification
2010	Mt Olive	Duplin	NC	230/115	300	New
	Selma	Johnston	NC	230/115	400	Uprate
2011	West End	Moore	NC	230/115	600	Uprate
	Fayetteville	Cumberland	NC	230/115	600	Uprate
	RTP Switching Sta.	Wake	NC	230/115	N/A	New
2012	Folkstone	Onslow	NC	230/115	200	New
2013	Laurinburg	Scotland	NC	230/115	600	Uprate

Rule R8-62: Certificates of environmental compatibility and public convenience and necessity for the construction of electric transmission lines in North Carolina.

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(1) For existing lines, the information required on FERC Form 1, pages 422, 423, 424, and 425, except that the information reported on pages 422 and 423 may be reported every five years.

See following pages.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Cumberland	Richmond	500.00	500.00	T	56.62		1
2	Cumberland	Wake	500.00	500.00	T	67.26		1
3	Mayo	Person	500.00	500.00	T	9.94		1
4	Mayo	Wake	500.00	500.00	T	73.27		1
5	Richmond	Newport (Duke)	500.00	500.00	T	32.69		1
6	Wake	Carson (VEPCO)	500.00	500.00	T	52.60		1
7	Tot. 500kV Lines in NC							
8	Apex US 1	Cary Regency Park	230.00	230.00	S-HFR	0.13		1
9	Asheboro	Biscoe	230.00	230.00	S-HFR	0.18		1
10	Asheboro	Biscoe	230.00	230.00	W-HFR	25.65		1
11	Asheboro	Siler City	230.00	230.00	W-HFR	8.94		1
12	Asheboro	Siler City	230.00	230.00	S-HFR	1.10		1
13	Asheboro	Siler City	230.00	230.00	C-HFR	15.69		1
14	Asheville Plant	Pisgah Forest (DPC)	230.00	230.00	DC-T	0.18		2
15	Asheville Plant	Pisgah Forest (DPC)	230.00	230.00	W-H Fr.	3.43		1
16	Asheville Plant	Pisgah Forest (DPC)	230.00	230.00	W-H Fr.	3.43	0.18	1
17	Aurora	Aurora PCS (Black)	230.00	230.00	DC-CP	0.74		2
18	Aurora	Aurora PCS (Black)	230.00	230.00	W-H Fr.	8.35		1
19	Aurora	Aurora PCS (Black)	230.00	230.00	DC S-HFR	5.49		2
20	Aurora	Aurora PCS (Black)	230.00	230.00	S-SP	0.28		1
21	Aurora	Aurora PCS (Black)	230.00	230.00	W-HFR	-6.14		-1
22	Aurora	Aurora PCS (Black)	230.00	230.00	DC C-SP	-0.74		-2
23	Aurora	Aurora PCS (White)	230.00	230.00	W-HFR	-6.09		-1
24	Aurora	Aurora PCS (White)	230.00	230.00	DC C-SP	-0.74		-2
25	Aurora	Aurora PCS (White)	230.00	230.00	DC S-HFR	5.47		2
26	Aurora	Aurora PCS (White)	230.00	230.00	S-SP	0.25		1
27	Aurora	Aurora PCS (White)	230.00	230.00	W-H Fr.	8.31	0.74	1
28	Aurora	Greenville	230.00	230.00	DC-T	1.87		2
29	Aurora	Greenville	230.00	230.00	W-H Fr.	36.77		1
30	Aurora	New Bern	230.00	230.00	W-H Fr.	27.75		1
31	Biscoe	Rockingham	230.00	230.00	S-HFR	0.18		1
32	Biscoe	Rockingham	230.00	230.00	W-HFR	36.83		1
33	Brunswick Plant	Castle Hayne (East)	230.00	230.00	S-HFR	1.21		1
34	Brunswick Plant	Castle Hayne (East)	230.00	230.00	DC-T	1.15		2
35	Brunswick Plant	Castle Hayne (East)	230.00	230.00	W-H Fr.	24.43		1
36					TOTAL	5,712.76	145.11	436

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1590MCMA(B)								1
1590MCMA(B)								2
1590MCMA(B)								3
1590MCMA(B)								4
2515MCMA(B)								5
2515MCMA(B)								6
	23,557,293	75,688,869	99,246,162					7
2-1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA(B)								11
1272MCMA(B)								12
1272MCMA(B)								13
1272MCMA								14
1272MCMA								15
1272MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
1109MCMA								28
1272&1109MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
2515MCMA								33
2500MCMA								34
1272&2515MCMA								35
	123,108,347	583,363,493	706,471,840	1,287,585	10,854,351		12,141,936	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Brunswick Plant	Castle Hayne (East)	230.00	230.00	S-SP	7.21		1
2	Brunswick Plant	Castle Hayne (East)	230.00	230.00	C-SP	0.70		1
3	Brunswick Plant	Delco (East)	230.00	230.00	DC-T	0.17		2
4	Brunswick Plant	Delco (East)	230.00	230.00	W-H Fr.	29.85		1
5	Brunswick Plant	Delco (East)	230.00	230.00	S-HFR	1.13		1
6	Brunswick Plant	Jacksonville	230.00	230.00	W-H Fr.	75.21		1
7	Brunswick Plant	Weatherspoon Plant	230.00	230.00	DC-T	0.28		2
8	Brunswick Plant	Weatherspoon Plant	230.00	230.00	W-H Fr.	77.65		1
9	Brunswick Plant	Wilmington Corning SW Sta	230.00	230.00	S-SP	7.04		1
10	Brunswick Plant	Wilmington Corning SW Sta	230.00	230.00	W-H Fr.	17.13	1.15	1
11	Brunswick Plant	Wilmington Corning SW Sta	230.00	230.00	S-H Fr.	1.36		1
12	Brunswick Plant	Delco (West)	230.00	230.00	W-H Fr.	30.35		1
13	Brunswick Plant	Delco (West)	230.00	230.00	S-H Fr.	1.08		1
14	Brunswick Plant	Wallace	230.00	230.00	W-H Fr.	53.57		1
15	Brunswick Plant	Wallace	230.00	230.00	S-H Fr.	1.25		1
16	Brunswick Plant	Whiteville	230.00	230.00	W-H Fr.	47.74		1
17	Brunswick Plant	Whiteville	230.00	230.00	S-H Fr.	1.07		1
18	Cane River	Nagel East & West(APCO)	230.00	230.00	DC-T	15.01		2
19	Cane River	Craggy	230.00	230.00	S-H Fr.	26.39		1
20	Cape Fear Plant	Harris Plant (North)	230.00	230.00	W-H Fr.	7.12		1
21	Cape Fear Plant	Harris Plant (North)	230.00	230.00	S-H Fr.	0.25		1
22	Cape Fear Plant	Harris Plant (South)	230.00	230.00	W-H Fr.	6.14		1
23	Cape Fear Plant	Harris Plant (South)	230.00	230.00	S-H Fr.	0.38		1
24	Cape Fear Plant	Jonesboro	230.00	230.00	W-H Fr.	10.10		1
25	Cape Fear Plant	West End	230.00	230.00	W-H Fr.	37.30		1
26	Cary Regency Park	Durham	230.00	230.00	W-H Fr.	18.46		1
27	Cary Regency Park	Durham	230.00	230.00	S-HFR	0.30		1
28	Cary Regency Park	Durham	230.00	230.00	S-SP	2.23		1
29	Cary Regency Park	Durham	230.00	230.00	S-HFR	0.14		1
30	Cary Regency Park	Method	230.00	230.00	DC-SSP	0.22		2
31	Cary Regency Park	Method	230.00	230.00	S-SP	4.53		1
32	Cary Regency Park	Method	230.00	230.00	W-H Fr.	4.00		1
33	Castle Hayne	Jacksonville	230.00	230.00	W-H Fr.	44.90		1
34	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	S-SP	0.45		1
35	Castle Hayne	Wilmington Corning SW. Sta.	230.00	230.00	W-HFR	5.12		1
36					TOTAL	5,712.76	145.11	436

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2515MCMA								1
1272MCMA								2
1272MCMA								3
1272MCMA								4
1272MCMA								5
1272MCMA								6
1272MCMA								7
1272MCMA								8
1272MCMA								9
1272&2515MCMA								10
2515MCMA								11
1272MCMA								12
1272MCMA								13
1272MCMA								14
1272MCMA								15
1272MCMA								16
1272MCMA								17
1590MCMA								18
1590MCMA								19
2515&1272MCMA(								20
1272MCMA(B)								21
1272MCMA(B)								22
1272MCMA(B)								23
795&1272MCMA(B)								24
1272&2515MCMA								25
1272MCMA								26
1272MCMA								27
1272MCMA								28
1272 MCMA								29
2515MCMA								30
2515&1272MCMA								31
1272MCMA(B)								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	123,108,347	583,363,493	706,471,840	1,287,585	10,854,351		12,141,936	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Clinton	Erwin	230.00	230.00	S-SP	1.76		1
2	Clinton	Erwin	230.00	230.00	W-H Fr.	32.56		1
3	Clinton	Wallace	230.00	230.00	W-H Fr.	36.68		1
4	Cumberland	Delco	230.00	230.00	W-H Fr.	54.40		1
5	Cumberland	Fayetteville (North)	230.00	230.00	DC-SSP	5.16		2
6	Cumberland	Fayetteville (North)	230.00	230.00	W-H Fr.	8.58		1
7	Cumberland	Fayetteville (South)	230.00	230.00	W-H Fr.	8.57		1
8	Cumberland	Whiteville	230.00	230.00	W-H Fr.	40.93		1
9	Durham	East Durham (DPC)	230.00	230.00	DC-SH Fr.	0.75		2
10	Durham	East Durham (DPC)	230.00	230.00	C-H Fr.	0.60		1
11	Durham	East Durham (DPC)	230.00	230.00	W-H Fr.	8.31		1
12	Durham	Method	230.00	230.00	DC-SSP	1.52		2
13	Durham	Method	230.00	230.00	S-SP	1.23		1
14	Durham	Method	230.00	230.00	W-H Fr.	13.24		1
15	Erwin	Fayetteville East	230.00	230.00	W-H Fr.	23.09		1
16	Erwin	Milburnie	230.00	230.00	S-SP	0.71		1
17	Erwin	Milburnie	230.00	230.00	DC-T	1.33		2
18	Erwin	Milburnie	230.00	230.00	W-H Fr.	34.08		1
19	Erwin	Selma	230.00	230.00	S-SP	1.08		1
20	Erwin	Selma	230.00	230.00	W-H Fr.	24.12		1
21	Falls	Milburnie	230.00	230.00	DC-T	10.92		2
22	Falls	Milburnie	230.00	230.00	S-H Fr.	0.32		1
23	Fayetteville	Fayetteville East	230.00	230.00	DC-T	0.97		2
24	Fayetteville	Fayetteville East	230.00	230.00	W-H Fr.	9.82		1
25	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	DC-SSP	0.21		2
26	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	S-SP	3.00		1
27	Fayetteville	Fort Bragg Woodruff St.	230.00	230.00	W-H Fr.	17.53		1
28	Fayetteville	Raeford	230.00	230.00	DC-SSP	1.88		2
29	Fayetteville	Raeford	230.00	230.00	W-H Fr.	15.04		1
30	Fayetteville	Rockingham	230.00	230.00	W-H Fr.	51.52	1.88	1
31	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	DC-SH Fr.	6.55		2
32	Fayetteville East	Fort Bragg Woodruff St.	230.00	230.00	S-SP	3.47	0.21	1
33	Greenville	Everetts (VP)	230.00	230.00	DC-T	0.61		1
34	Greenville	Wilson	230.00	230.00	W-H Fr.	34.32		1
35	Greenville	Wilson	230.00	230.00	DC-T	0.48		1
36					TOTAL	5,712.76	145.11	436

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMA								1
1272MCMA								2
1272&556MCMA(B)								3
1272MCMA								4
2515MCMA								5
2515MCMA								6
2515MCMA								7
1272&2515MCMA								8
1272MCMA(B)								9
1272MCMA(B)								10
1272MCMA(B)								11
2515MCMA								12
2515MCMA								13
2515&1272MCMA(								14
1272MCMA								15
1272MCMA								16
1272MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1272MCMA								21
1272MCMA								22
1272MCMA								23
1272MCMA								24
1272MCMA(B)								25
2515&1272MCMA(								26
1272MCMA(B)								27
1272MCMA(B)								28
1272MCMA(B)								29
1272MCMA								30
1590MCMA								31
1590MCMA								32
1109MCMA								33
1272&546MCMA(B)								34
546MCMA(B)								35
	123,108,347	583,363,493	706,471,840	1,267,585	10,854,351		12,141,936	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/10/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Harris Plant	Siler City	230.00	230.00	S-H Fr.	1.44		1
2	Harris Plant	Siler City	230.00	230.00	W-H Fr.	30.04		1
3	Harris Plant	Apex US #1	230.00	230.00	W-H Fr.	3.94		1
4	Harris Plant	Erwin	230.00	230.00	S-H Fr.	0.27		1
5	Harris Plant	Erwin	230.00	230.00	W-H Fr.	29.50		1
6	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	DC-SSP	1.15		2
7	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	S-H Fr.	0.20		1
8	Harris Plant	Fort Bragg Woodruff St.	230.00	230.00	W-H Fr.	34.30		1
9	Harris Plant	Wake	230.00	230.00	S-SP	5.39		1
10	Harris Plant	Wake	230.00	230.00	S-H Fr.	32.39		1
11	Havelock	Jacksonville	230.00	230.00	DC-T	5.61		2
12	Havelock	Jacksonville	230.00	230.00	W-H Fr.	32.64		1
13	Havelock	Morehead Wildwood	230.00	230.00	DC-SSP	0.27		2
14	Havelock	Morehead Wildwood	230.00	230.00	W-H Fr.	14.82		1
15	Havelock	Morehead Wildwood	230.00	230.00	S-SP	0.23		1
16	Havelock	New Bern	230.00	230.00	DC-T	0.13		2
17	Havelock	New Bern	230.00	230.00	W-H Fr.	23.34		1
18	Henderson	Person	230.00	230.00	DC-T	2.46		2
19	Henderson	Person	230.00	230.00	W-H Fr.	37.47		1
20	Jacksonville	New Bern	230.00	230.00	W-H Fr.	30.41		1
21	Jacksonville	Wallace	230.00	230.00	W-H Fr.	30.82		1
22	Kinston DuPont	Wommack	230.00	230.00	S-SP	0.14		1
23	Kinston DuPont	Wommack	230.00	230.00	W-H Fr.	2.21		1
24	Kinston DuPont	Wommack	230.00	230.00	S-HFR	16.85		1
25	Laurinburg	Richmond	230.00	230.00	C-SP	3.32		1
26	Laurinburg	Richmond	230.00	230.00	W-H Fr.	17.12		1
27	Lee Sub	Milburnie	230.00	230.00	S-SP	0.43		1
28	Lee Sub	Milburnie	230.00	230.00	W-H Fr.	38.38	1.36	1
29	Lee Sub	New Bern	230.00	230.00	W-H Fr.	61.68		1
30	Lee Sub	Selma	230.00	230.00	S-SP	0.24		1
31	Lee Sub	Selma	230.00	230.00	W-H Fr.	16.54		1
32	Lee Sub	Wommack (North)	230.00	230.00	W-H Fr.	31.08		1
33	Lilesville	DPC Oakboro (Black)	230.00	230.00	S-HFR	0.30		1
34	Lilesville	DPC Oakboro (White)	230.00	230.00	S-HFR	0.32		1
35	Lilesville	Rockingham (Black)	230.00	230.00	S-HFR	0.18		1
36					TOTAL	5,712.76	145.11	436

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272MCMA(B)								1
2515&1272MCMA(								2
1272MCMA(B)								3
1272MCMA(B)								4
1272MCMA(B)								5
1272MCMA(B)								6
1272MCMA(B)								7
1272MCMA(B)								8
1590MCMA(B)								9
1590MCMA(B)								10
1272MCMA								11
1272&556MCMA(B)								12
1590MCMA								13
1590MCMA								14
1590MCMA								15
1272MCMA								16
1272MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1272MCMA								21
1272MCMA								22
1272MCMA								23
1272MCMA								24
2515MCMA								25
2515&1272MCMA(								26
1272MCMA								27
1272MCMA								28
1272&1590MCMA								29
2515&1272MCMA(								30
1272MCMA(B)								31
1272MCMA(B)								32
1272 MCMA								33
1272 MCMA								34
1272 MCMA								35
	123,108,347	583,363,493	706,471,840	1,287,585	10,854,351		12,141,936	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Lilesville	Rockingham (White)	230.00	230.00	S-HFR	0.18		1
2	MARION	WHITEVILLE	230.00	230.00	S-SP	14.49		1
3	Method	East Durham (DPC)	230.00	230.00	DC-SH Fr.	0.77		2
4	Method	East Durham (DPC)	230.00	230.00	S-SP	4.36		1
5	Method	East Durham (DPC)	230.00	230.00	C-H Fr.	0.55		1
6	Method	East Durham (DPC)	230.00	230.00	W-H Fr.	14.17	1.53	1
7	Method	East Durham (DPC)	230.00	230.00	S-H Fr.	0.55		1
8	Method	Milburnie	230.00	230.00	DC-SSP	3.38		2
9	Method	Milburnie	230.00	230.00	S-SP	3.79		1
10	Method	Milburnie	230.00	230.00	W-SP	5.31	0.26	1
11	Milburnie	Person	230.00	230.00	DC-T	47.74		2
12	Milburnie	Person	230.00	230.00	S-H Fr.	0.49		1
13	Milburnie	Person	230.00	230.00	W-H Fr.	0.49	10.92	1
14	Milburnie	Wake	230.00	230.00	W-H Fr.	7.00		1
15	New Bern	Wommack (North)	230.00	230.00	S-H Fr.	3.11		1
16	New Bern	Wommack (North)	230.00	230.00	S-SP	0.14		1
17	New Bern	Wommack (North)	230.00	230.00	W-H Fr.	29.32	0.14	1
18	Person	Rocky Mount	230.00	230.00	DC-SSP	0.18		2
19	Person	Rocky Mount	230.00	230.00	T	8.59		1
20	Person	Rocky Mount	230.00	230.00	W-H Fr.	69.41	2.47	1
21	Person	Halifax (VP)	230.00	230.00	W-H Fr.	4.85		1
22	Raeford	Richmond	230.00	230.00	W-H Fr.	35.17		1
23	Richmond	Rockingham	230.00	230.00	S-HFR	0.40		1
24	Richmond	Rockingham	230.00	230.00	W-H Fr.	5.57		1
25	Richmond	Rockingham	230.00	230.00	DCS C-SP	1.41		1
26	Richmond	Rockingham	230.00	230.00	S-HFR	6.40		1
27	Richmond County Plant	Richmond Substation (Black)	230.00	230.00	S-HFR	1.09		1
28	Richmond County Plant	Richmond Substation (White)	230.00	230.00	S-HFR	0.88		1
29	Rockingham	Oakboro (DPC) B&W	230.00	230.00	DC-T	34.83		2
30	Rockingham	West End	230.00	230.00	DC-T	5.72		2
31	Rockingham	West End	230.00	230.00	W-H Fr.	28.24		1
32	Rocky Mount	Edgecombe (VP)	230.00	230.00	DC-T	4.25		2
33	Rocky Mount	Edgecombe (VP)	230.00	230.00	DC-SSP	0.30		2
34	Rocky Mount	Hornertown (VP)	230.00	230.00	T		4.55	2
35	Rocky Mount	Wilson	230.00	230.00	S-SP	0.85		1
36					TOTAL	5,712.76	145.11	436

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 MCMA								1
1590MCMA								2
1272MCMA(B)								3
2515MCMA								4
1272MCMA(B)								5
2515&1272MCMA(								6
1272MCMA(B)								7
1272MCMA								8
1272MCMA								9
1272MCMA								10
1272MCMA								11
1272MCMA								12
1272MCMA								13
1272MCMA(B)								14
1272MCMA								15
1272MCMA								16
1272MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
1272MCMA								21
1272MCMA(B)								22
2-1272MCMA(B)								23
1272MCMA(B)								24
21590MCMA								25
21590MCMA								26
21590MCMA(B)								27
21590MCMA(B)								28
954MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1590MCMA								35
	123,108,347	583,363,493	706,471,840	1,287,585	10,854,351		12,141,936	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/10/2000	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Rocky Mount	Wilson	230.00	230.00	DC-SSP	8.26		2
2	Rocky Mount	Wilson	230.00	230.00	DC S-HFR	3.68		2
3	Roxboro Plant	East Danville (AEP) (North)	230.00	230.00	S-HFR	1.79		1
4	Roxboro Plant	East Danville (AEP) (North)	230.00	230.00	DC S-HFR	7.26		2
5	Roxboro Plant	East Danville (AEP) (North)	230.00	230.00	DC S-SP	1.74		2
6	Roxboro Plant	East Danville (AEP) (South)	230.00	230.00	S-HFR	1.82		1
7	Roxboro Plant	East Danville (AEP) (South)	230.00	230.00	DC S-HFR	7.26		2
8	Roxboro Plant	East Danville (AEP) (South)	230.00	230.00	DC S-SP	1.74		2
9	Roxboro Plant	Falls	230.00	230.00	DC-T	0.15		2
10	Roxboro Plant	Falls	230.00	230.00	C-SP	0.21		1
11	Roxboro Plant	Falls	230.00	230.00	S-H Fr.	0.17		1
12	Roxboro Plant	Falls	230.00	230.00	W-H Fr.	1.55	47.74	1
13	Roxboro Plant	East Durham (East) (DPC)	230.00	230.00	C-H Fr.	1.65		1
14	Roxboro Plant	East Durham (East) (DPC)	230.00	230.00	W-H Fr.	31.99	0.76	1
15	Roxboro Plant	East Durham (West) (DPC)	230.00	230.00	C-H Fr.	1.71		1
16	Roxboro Plant	East Durham (West) (DPC)	230.00	230.00	W-H Fr.	31.98	0.77	1
17	Roxboro Plant	Eno (DPC) B&W	230.00	230.00	DC-T	16.89		2
18	Roxboro Plant	Person (Middle)	230.00	230.00	T	0.14		1
19	Roxboro Plant	Person (Middle)	230.00	230.00	C-H Fr.	0.10		1
20	Roxboro Plant	Person (Middle)	230.00	230.00	S-H Fr.	1.83		1
21	Roxboro Plant	Person (CEFFO)	230.00	230.00	C-SP	0.21		1
22	Roxboro Plant	Person (CEFFO)	230.00	230.00	W-H Fr.	1.90	0.15	1
23	Roxboro Plant	Person (HYCO)	230.00	230.00	T	0.08		1
24	Roxboro Plant	Person (HYCO)	230.00	230.00	W-H Fr.	1.18		1
25	Selma	Wake	230.00	230.00	W-H Fr.	21.00		1
26	Sutton Plant	Castle Hayne	230.00	230.00	DC-T	0.11		2
27	Sutton Plant	Castle Hayne	230.00	230.00	W-H Fr.	13.82		1
28	Sutton Plant	Delco	230.00	230.00	W-H Fr.	14.90	0.28	1
29	Sutton Plant	Wallace	230.00	230.00	T	0.45		1
30	Sutton Plant	Wallace	230.00	230.00	W-H Fr.	31.89		1
31	Wake	Zebulon	230.00	230.00	W-H Fr.	10.74		1
32	Wake	Zebulon	230.00	230.00	S-H Fr.	0.49		1
33	Weatherspoon Plant	Fayetteville	230.00	230.00	W-H Fr.	32.55	0.97	1
34	Weatherspoon Plant	Latta	230.00	230.00	T	0.37		1
35	Weatherspoon Plant	Latta	230.00	230.00	W-H Fr.	31.74	0.28	1
36					TOTAL	5,712.76	145.11	436

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1590MCMA								1
1590MCMA								2
1590MCMA								3
1590MCMA								4
1590MCMA								5
1590MCMA								6
1590MCMA								7
1590MCMA								8
1272MCMA								9
1590MCMA								10
1272MCMA								11
1272&1590MCMA								12
1272MCMA(B)								13
1272MCMA(B)								14
1272MCMA(B)								15
1272MCMA(B)								16
1272MCMA(B)								17
1272MCMA(B)								18
1272MCMA(B)								19
1590MCMA(B)								20
1590MCMA(B)								21
1590MCMA(B)								22
2515MCMA								23
1272&2515MCMA(								24
2515&1272MCMA(								25
1272MCMA								26
1272MCMA								27
1272MCMA								28
1272MCMA								29
1272MCMA								30
1272MCMA(B)								31
1272MCMA(B)								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	123,108,347	583,363,493	706,471,840	1,287,585	10,854,351		12,141,936	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Weatherspoon Plant	Laurinburg	230.00	230.00	W-H Fr.	31.46		1
2	Weatherspoon Plant	Laurinburg	230.00	230.00	S-H Fr.	0.99		1
3	Wayne County Plant	Lee Substation	230.00	230.00	S-HFR	0.31		1
4	Wilmington Corning SW Sta.	Wilmington Corning Sub. (N)	230.00	230.00	S-SP	0.48		1
5	Wilmington Corning SW Sta.	Wilmington Corning Sub (S)	230.00	230.00	S-SP	0.43		1
6	Wilson	Zebulon	230.00	230.00	W-H Fr.	25.92		1
7	Wilson	Zebulon	230.00	230.00	S-H Fr.	0.46		1
8	Tap Point	Angier	230.00	230.00	W-H Fr.	0.11		1
9	Tap Point	Ansonville	230.00	230.00	S-SP	0.03		1
10	Tap Point	Apex (Bank #1)	230.00	230.00	W-H Fr.	0.01		1
11	Tap Point	Apex (Bank #2)	230.00	230.00	S-HFR	0.01		1
12	Tap Point	Apex (Bank #3)	230.00	230.00	S-HFR	0.03		1
13	Tap Point	Auburn	230.00	230.00	W-H Fr.	0.10		1
14	Tap Point	Bahama	230.00	230.00	W-H Fr.	0.06		1
15	Tap Point	Bailey	230.00	230.00	W-H Fr.	1.38		1
16	Tap Point	Bayboro	230.00	230.00	W-H Fr.	2.13		1
17	Tap Point	Benson	230.00	230.00	W-H Fr.	0.01		1
18	Tap Point	Benson PGI	230.00	230.00	W-H Fr.	1.98		1
19	Tap Point	Bonnie Doone	230.00	230.00	W-H Fr.	0.17		1
20	Tap Point	Buies Creek	230.00	230.00	W-H Fr.	0.06		1
21	Tap Point	Bynum	230.00	230.00	S-HFR	0.06		1
22	Tap Point	Bynum	230.00	230.00	W-H Fr.	9.26		1
23	Tap Point	Camden 230/23kV Yard	230.00	230.00	W-HFR	0.18		1
24	Tap Point	Camp LeJeune #1	230.00	230.00	W-H Fr.	4.65		1
25	Tap Point	Camp LeJeune #2	230.00	230.00	W-H Fr.	0.04		1
26	Tap Point	Cary	230.00	230.00	W-H Fr.	0.93		1
27	Tap Point	Cary Evans Road (East)	230.00	230.00	W-H Fr.	0.04		1
28	Tap Point	Cary Evans Road (West)	230.00	230.00	S-HFR	0.04		1
29	Tap Point	Cary Triangle Forest	230.00	230.00	W-H Fr.	0.04		1
30	Tap Point	Catherine Lake	230.00	230.00	W-H Fr.	0.08		1
31	Tap Point	Chocowinity	230.00	230.00	W-H Fr.	0.05		1
32	Tap Point	Clifdale	230.00	230.00	W-H Fr.	0.54		1
33	Tap Point	Concord	230.00	230.00	S-HFR	0.13		1
34	Tap Point	Craven County Wood Energy	230.00	230.00	W-H Fr.	1.87		1
35	Tap Point	Dudley Georgia Pacific	230.00	230.00	W-H Fr.	2.64		1
36					TOTAL	5,712.76	145.11	436

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereot, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272&2515MCMA								1
1272MCMA								2
1590MCMA(B)								3
795MCMA								4
795MCMA								5
1272MCMA(B)&251								6
1272MCMA(B)								7
795MCMA								8
795MCMA								9
795MCMA								10
795MCMA								11
795MCMA								12
1272MCMA								13
795MCMA								14
795MCMA								15
1272MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
1272MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
795MCMA								30
1272MCMA								31
795MCMA								32
795MCMA								33
795MCMA								34
795MCMA								35
	123,108,347	583,363,493	706,471,840	1,287,585	10,854,351		12,141,936	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Tap Point	Ellerbe	230.00	230.00	W-H Fr.	0.04		1
2	Tap Point	Fort Bragg Knox St.	230.00	230.00	W-H Fr.	0.08		1
3	Tap Point	Fort Bragg Longstreet Road	230.00	230.00	W-H Fr.	3.19		1
4	Tap Point	Fort Bragg Main	230.00	230.00	S-SP	0.04		1
5	Tap Point	Four Oaks	230.00	230.00	W-H Fr.	0.07		1
6	Tap Point	Fuquay	230.00	230.00	W-H Fr.	0.48		1
7	Tap Point	Fuquay Bells Lake	230.00	230.00	W-H Fr.	0.15		1
8	Tap Point	Garland	230.00	230.00	W-H Fr.	0.06		1
9	Tap Point	Garner Panther Branch	230.00	230.00	W-H Fr.	0.15		1
10	Tap Point	Camp Geiger	230.00	230.00	S-SP	1.94		1
11	Tap Point	Grantham	230.00	230.00	W-H Fr.	0.10		1
12	Tap Point	Hamlet	230.00	230.00	W-H Fr.	0.02		1
13	Tap Point	Hamlet	230.00	230.00	S-HFR	0.02		1
14	Tap Point	Henderson East	230.00	230.00	W-H Fr.	0.06		1
15	Tap Point	Holly Springs (East)	230.00	230.00	S-HFR	0.11		1
16	Tap Point	Holly Springs (West)	230.00	230.00	S-HFR	0.11		1
17	Tap Point	Hope Mills Rockfish Road	230.00	230.00	W-H Fr.	0.07		1
18	Tap Point	Jacksonville Tarawa	230.00	230.00	W-H Fr.	0.04		1
19	Tap Point	Knightdale Square D	230.00	230.00	W-H Fr.	0.95		1
20	Tap Point	Laurel Hills	230.00	230.00	W-H Fr.	0.03		1
21	Tap Point	Laurinburg City	230.00	230.00	W-H Fr.	0.03		1
22	Tap Point	Leesville Wood Valley	230.00	230.00	W-H Fr.	0.15		1
23	Tap Point	Lumberton POD#3	230.00	230.00	S-SP	0.70		1
24	Tap Point	Masonboro	230.00	230.00	S-SP	0.03		1
25	Tap Point	Mayo Plant	230.00	230.00	W-H Fr.	3.06		1
26	Tap Point	Morrisville	230.00	230.00	W-H Fr.	0.11		1
27	Tap Point	New Bern West	230.00	230.00	W-H Fr.	0.04		1
28	Tap Point	New Hill	230.00	230.00	W-H Fr.	0.20		1
29	Tap Point	Newton Grove	230.00	230.00	W-H Fr.	2.13		1
30	Tap Point	Oxford North	230.00	230.00	W-H Fr.	0.92		1
31	Tap Point	Oxford South	230.00	230.00	W-H Fr.	6.30		1
32	Tap Point	Pittsboro	230.00	230.00	W-H Fr.	0.03		1
33	Tap Point	Prospect	230.00	230.00	W-H Fr.	0.03		1
34	Tap Point	Raleigh Blue Ridge Road	230.00	230.00	S-SP	0.03		1
35	Tap Point	Raleigh Durham Airport	230.00	230.00	W-H Fr.	0.09		1
36					TOTAL	5,712.76	145.11	436

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Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795MCMA								1
795MCMA								2
795MCMA								3
795MCMA								4
795MCMA								5
795MCMA								6
795MCMA								7
795MCMA								8
795MCMA								9
1272MCMA								10
795MCMA								11
1272MCMA								12
1272MCMA								13
1272MCMA								14
795MCMA								15
795MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
795MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
1272MCMA								30
795MCMA								31
795MCMA								32
795MCMA								33
795MCMA								34
795MCMA								35
	123,108,347	583,363,493	706,471,840	1,287,585	10,854,351		12,141,936	36

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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Tap Point	Raleigh Foxcroft	230.00	230.00	W-H Fr.	0.03		1
2	Tap Point	Raleigh Homestead (North)	230.00	230.00	S-HFR	0.07		1
3	Tap Point	Raleigh Homestead (South)	230.00	230.00	S-HFR	0.07		1
4	Tap Point	Raleigh Honeycutt	230.00	230.00	S-SP	2.08		1
5	Tap Point	Raleigh Leesville Road	230.00	230.00	W-H Fr.	0.04		1
6	Tap Point	Raleigh NCSU Centennial	230.00	230.00	S-SP	0.05		1
7	Tap Point	Raleigh Oakdale	230.00	230.00	S-SP	1.26		1
8	Tap Point	Raleigh Six Forks	230.00	230.00	S-H Fr.	0.07		1
9	Tap Point	Rhems	230.00	230.00	W-H Fr.	0.04		1
10	Tap Point	Rockingham Aberdeen Road	230.00	230.00	W-H Fr.	0.60		1
11	Tap Point	Rolesville	230.00	230.00	W-H Fr.	5.67		1
12	Tap Point	Rose Hill	230.00	230.00	W-H Fr.	0.16		1
13	Tap Point	Rowland	230.00	230.00	W-H Fr.	6.86		1
14	Tap Point	Roxboro Bowmantown Road	230.00	230.00	S-HFR	0.04		1
15	Tap Point	Roxboro Cogentrix	230.00	230.00	W-H Fr.	0.60		1
16	Tap Point	Roxb. Plt Unit #3 C. Tower	230.00	230.00	W-H Fr.	0.24		1
17	Tap Point	Roxboro South	230.00	230.00	W-H Fr	0.79		1
18	Tap Point	Sanford Deep River	230.00	230.00	W-H Fr.	2.63		1
19	Tap Point	Sanford Deep River	230.00	230.00	S-HFR	0.09		1
20	Tap Point	Sanford Garden Street	230.00	230.00	W-H Fr.	3.25		1
21	Tap Point	Sanford Homer Blvd.	230.00	230.00	W-H Fr.	0.04		1
22	Tap Point	Scotts Hill	230.00	230.00	S-SP	3.37		1
23	Tap Point	Siler City Hwy. 64	230.00	230.00	S-HFR	0.53		1
24	Tap Point	Southport	230.00	230.00	W-H Fr.	1.88		1
25	Tap Point - DE-ENERGIZED	Southport Adm (East)	230.00	230.00	W-H Fr.	2.18		1
26	Tap Point	Southport Adm (West)	230.00	230.00	W-H Fr.	0.48		1
27	Tap Point	Southport Cogentrix	230.00	230.00	W-H Fr.	0.30		1
28	Tap Point	Summerton	230.00	230.00	W-H Fr.	2.70		1
29	Tap Point	Swansbsoro	230.00	230.00	W-H Fr.	0.07		1
30	Tap Point	Tideland EMC Edwards	230.00	230.00	S-SP	0.61		1
31	Tap Point	Topsail	230.00	230.00	W-H Fr.	1.55		1
32	Tap Point	Town of Apex POD #4	230.00	230.00	S-HFR	0.12		1
33	Tap Point	Wadesboro Bowman School	230.00	230.00	W-H Fr.	3.30		1
34	Tap Point	Warsaw	230.00	230.00	S-SP	0.61		1
35	Tap Point	Warsaw	230.00	230.00	W-H Fr.	2.46		1
36					TOTAL	5,712.76	145.11	436

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Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795MCMA								1
1272MCMA								2
1272MCMA								3
1590MCMA(B)								4
795MCMA								5
1272MCMA								6
795MCMA								7
1272MCMA								8
795MCMA								9
795MCMA								10
1590MCMA								11
795MCMA								12
795MCMA								13
1272MCMA								14
795MCMA								15
795MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
1590MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
1272MCMA								24
1272MCMA								25
1272MCMA								26
795MCMA								27
795MCMA								28
795MCMA								29
1590MCMA								30
795MCMA								31
795 MCMA								32
795MCMA								33
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Tap Point	Weatherspoon Sub	230.00	230.00	W-H Fr.	0.09		1
2	Tap Point	Wendell	230.00	230.00	W-H Fr.	0.07		1
3	Tap Point	Wilmington Kosa	230.00	230.00	W-H Fr.	0.58		1
4	Tap Point	Wilmington Cedar Avenue	230.00	230.00	S-SP	0.21		1
5	Tap Point	Wilmington East	230.00	230.00	W-H Fr.	0.01		1
6	Tap Point	Wilmington Ninth & Orange	230.00	230.00	S-SP	2.01		1
7	Tap Point	Wilmington Ogden (East)	230.00	230.00	W-H Fr.	0.06		1
8	Tap Point	Wilmington Ogden (West)	230.00	230.00	S-HFR	0.06		1
9	Tap Point	Wilmington Praxair	230.00	230.00	W-H Fr.	0.58		1
10	Tap Point	Wilmington Basf	230.00	230.00	W-H Fr.	0.22		1
11	Tap Point	Wilson Mills	230.00	230.00	W-H Fr.	0.09		1
12	Tap Point	Yanceyville	230.00	230.00	S-SP	10.36		1
13	Tot. 230 kV Lines in NC							
14	Camden	Lugoff(SCPSA)	230.00	230.00	W-H Fr.	5.37		1
15	Darlington County Plant	Florence	230.00	230.00	S-SP	37.28		1
16	Darlington County Plant	Robinson Plant (South)	230.00	230.00	W-H Fr.	1.71		1
17	Darlington County Plant	Robinson Plant (North)	230.00	230.00	S-HFR	1.67		1
18	Darlington County Plant	South Bethune (SCPSA)	230.00	230.00	W-H Fr.	0.06		1
19	Darlington County Plant	Sumter	230.00	230.00	DC-SSP	5.68		2
20	Darlington County Plant	Sumter	230.00	230.00	W-H Fr.	48.01		1
21	Darlington County Plant	Laurinburg	230.00	230.00	W-H Fr.	51.53		1
22	Florence	Kingstree	230.00	230.00	W-H Fr.	49.46		1
23	Florence	Latta	230.00	230.00	W-H Fr.	23.49		1
24	Florence	Darlington (SCPSA)	230.00	230.00	W-H Fr.	11.05		1
25	Latta	Marion	230.00	230.00	W-H Fr.	8.49		1
26	MARION	SCPSA MARION NORTH	230.00	230.00	S-HFR	0.07		1
27	MARION	SCPSA MARION SOUTH	230.00	230.00	S-HFR	0.08		1
28	MARION	WHITEVILLE	230.00	230.00	S-SP	6.60		1
29	Robinson Plant	Florence	230.00	230.00	DC-T	1.40		2
30	Robinson Plant	Florence	230.00	230.00	W-H Fr.	38.41		1
31	Robinson Plant	Rockingham	230.00	230.00	S-SP	0.23		1
32	Robinson Plant	Rockingham	230.00	230.00	W-H Fr.	47.86	1.40	1
33	Robinson Plant	Darlington (SCPSA)	230.00	230.00	DC-T	0.60		2
34	Robinson Plant	Darlington (SCPSA)	230.00	230.00	W-H Fr.	17.95		1
35	Robinson Plant	Sumter	230.00	230.00	W-H Fr.	40.56	0.60	1
36					TOTAL	5,712.76	145.11	436

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Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795MCMA								1
795MCMA								2
1272MCMA								3
795MCMA								4
1272MCMA								5
1272MCMA								6
795MCMA								7
795MCMA								8
795MCMA								9
795MCMA								10
795MCMA								11
795MCMA								12
	56,083,420	267,431,585	323,515,005					13
1272MCMA								14
1590MCMA								15
2515MCMA								16
2515MCMA								17
1272MCMA								18
1272MCMA								19
1272MCMA								20
2515MCMA								21
1272MCMA								22
1272MCMA								23
1272MCMA								24
1590MCMA								25
2-1272MCMA								26
2-1272MCMA								27
1590MCMA								28
1272MCMA								29
1272MCMA								30
1272MCMA								31
1272MCMA								32
1272MCMA								33
1272MCMA								34
1272MCMA								35
	123,108,347	583,363,493	706,471,840	1,287,585	10,854,351		12,141,936	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Sumter	Canadys (SCE&G)	230.00	230.00	DC-T	7.26		2
2	Sumter	Canadys (SCE&G)	230.00	230.00	W-H Fr.	22.90		1
3	Sumter	Wateree Plant (SCE&G)	230.00	230.00	W-H Fr.	16.58	7.26	1
4	Tap Point	Bishopville	230.00	230.00	W-H Fr.	0.16		1
5	Tap Point	Cheraw Cash Rd.	230.00	230.00	S-SP	1.08		1
6	Tap Point	Cheraw Reid Park	230.00	230.00	W-H Fr.	5.30		1
7	Tap Point	Dillon North	230.00	230.00	S-SP	3.51		1
8	Tap Point	Dillon Maple	230.00	230.00	W-H Fr.	4.39		1
9	Tap Point	Dovesville Nucor	230.00	230.00	W-H Fr.	6.81		1
10	Tap Point	Elliott	230.00	230.00	W-H Fr.	2.15		1
11	Tap Point	Florence Cashua	230.00	230.00	C-SP	1.30		1
12	Tap Point	Florence Ebenezer	230.00	230.00	W-H Fr.	0.08		1
13	Tap Point	Florence West	230.00	230.00	W-H Fr	0.03		1
14	Tap Point	Hartsville Segars Mill	230.00	230.00	W-H Fr.	0.06		1
15	Tap Point	Hartsville Talley Metals	230.00	230.00	W-HFR	0.31		1
16	Tap Point	Hartsville Talley Metals	230.00	230.00	S-SP	0.74		1
17	Tap Point	Kingstree North	230.00	230.00	W-H Fr	0.14		1
18	Tap Point	Lake City	230.00	230.00	W-H Fr.	0.08		1
19	Tap Point	McColl	230.00	230.00	W-H Fr.	0.90		1
20	Tap Point	Olanta	230.00	230.00	W-H Fr.	0.05		1
21	Tap Point	Society Hill	230.00	230.00	W-SP	1.13		1
22	Tap Point	Summerton	230.00	230.00	W-HFR	2.70		1
23	Tap Point	Sumter Alice Drive	230.00	230.00	W-H Fr.	0.30		1
24	Tap Point	Sumter North	230.00	230.00	S-SP	0.73		1
25	Tap Point	Sumter Wedgefield Rd.	230.00	230.00	W-H Fr.	0.05		1
26	Tot. 230kV Lines In SC							
27	115kV Tower Lines-NC				T	339.91	37.89	6
28	115kV Pole Lines-NC				Wood Pole	1,564.18	19.08	14
29	Tot. 115kV Lines-NC							
30								
31								
32	115kV Tower Lines-SC				T	85.13		5
33	115kV Pole Lines-SC				Wood Pole	442.52	0.37	
34	Tot. 115Kv Lines in SC							
35	66KV Tower Lines NC				T	1.56	0.97	1
36					TOTAL	5,712.76	145.11	436

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795MCMA								1
795MCMA								2
1272MCMA								3
795MCMA								4
795MCMA								5
1272MCMA								6
795MCMA								7
795MCMA								8
1272MCMA								9
795MCMA								10
795MCMA								11
1590MCMA								12
795MCMA								13
795MCMA								14
795MCMA								15
1590MCMA								16
795MCMA								17
795MCMA								18
795MCMA								19
795MCMA								20
795MCMA								21
795MCMA								22
795MCMA								23
795MCMA								24
795MCMA								25
	11,486,966	54,775,144	66,262,110					26
								27
								28
	28,226,706	163,392,125	191,618,831					29
								30
								31
								32
								33
	3,696,734	21,398,788	25,095,522					34
								35
	123,108,347	583,363,493	706,471,840	1,287,585	10,854,351		12,141,936	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

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3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	66KV Pole Lines-NC				Wood Pole	15.15	1.20	1
2	Tot. 66KV Lines in NC							
3								
4	Tot. KV Lines							
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,712.76	145.11	436

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
	57,228	676,982	734,210					2
								3
				1,287,585	10,854,351		12,141,936	4
								5
								6
								7
								8
								9
								10
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								12
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	123,108,347	583,363,493	706,471,840	1,287,585	10,854,351		12,141,936	36

Name of Respondent	This Report Is:	Date of Report (Mo. Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	AURORA	AURORA PCS (BLACK)	5.49	DC-S-HFR	9.00	2	2
2	AURORA	AURORA PCS (BLACK)	0.28	S-SP	9.00	1	1
3	AURORA	AURORA PCS (WHITE)	5.47	DC S-HFR	9.00	2	2
4	AURORA	AURORA PCS (WHITE)	0.25	S-SP	9.00	1	1
5	AURORA	AURORA PCS (BLACK)	-6.14	W-HFR	-9.00	-1	-1
6	AURORA	AURORA PCS (BLACK)	-0.74	DC-C-SP	-12.00	-2	-2
7	AURORA	AURORA PCS (WHITE)	-6.09	W-HFR	-9.00	-1	-1
8	AURORA	AURORA PCS (WHITE)	-0.74	CS-C-SP	-12.00	-2	-2
9	RICHMOND SUB	ROCKINGHAM (WEST)	6.40	S-HFR	9.00	1	1
10	RICHMOND SUB	ROCKINGHAM (WEST)	1.41	DCS-C-SP	17.00	1	2
11	MARION	WHITEVILLE	14.49	S-SP	9.00	1	1
12	TAP POINT	HAMLET/BANK #2	0.02	S-HFR		1	1
13	TAP POINT	BYNUM/ BANK #2	0.06	S-HFR		1	1
14	TAP POINT	SANFORD DEEP RIVER	0.09	S-HFR		1	1
15	LAURINBURG	LIBBY OWENS FORD	2.75	S-SP	10.00	1	1
16	TAP POINT	WILMINGTON ATLANTIC	0.18	S-SP		1	1
17	TAP POINT	DAYCO CORP	-1.35	S-SP	-17.00	-1	-1
18	MARION	WHITEVILLE	6.60	S-SP	9.00	1	1
19	MARION	SCPSA MARION NORTH	0.07	S-HFR		1	1
20	MARION	SCPSA MARION SOUTH	0.08	S-HFR		1	1
21	ASHEVILLE PLANT	OTEEN	6.03	S-HFR	8.00	1	1
22	ASHEVILLE PLANT	OTEEN	-6.03	W-HFR	-8.00	-1	-1
23	TAP POINT	CITY OF CAMDEN	0.08	S-HFR		1	1
24	FLORENCE	MARION	0.48	S-HFR		1	1
25	TAP POINT	FLORENE BURCH'S	-0.19	W-HF		-1	-1
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		28.95		31.00	11	12

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Carolina Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	End of 2007/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
795	MCMA	VERT	230		754,258	176,296		930,554	1
795	MCMA	VERT	230		38,469	8,991		47,460	2
795	MCMA	VERT	230		827,316	223,661		1,050,977	3
795	MCMA	VERT	230		72,318	19,551		91,869	4
-795	MCMA	FLAT	230				764,085	764,085	5
-795	MCMA	VERT	230				92,088	92,088	6
-795	MCMA	FLAT	230				918,728	918,728	7
-795	MCMA	VERT	230				111,635	111,635	8
2-1590	MCMA	FLAT	230		2,656,334	2,219,888	96,054	4,972,276	9
2-1590	MCMA	VERT	230		585,224	489,069	21,162	1,095,455	10
1590	MCMA	VERT	115	774,186	5,401,536	3,617,640		9,793,362	11
1272	MCMA	FLAT	230		56,834	124,385		181,219	12
795	MCMA	FLAT	230		133,340	48,262		181,602	13
795	MCMA	FLAT	230		71,315	10,370		81,685	14
795	MCMA	VERT	115		913,186	928,238		1,841,424	15
336	MCMA	VERT	115		261,041	111,271		372,312	16
336	MCMA	VERT	115				39,156	39,156	17
1-590	MCMA	VERT	115	55,075	149,116	111,886	6,049	322,126	18
2-1272	MCMA	FLAT	230		36,733	4,090	23,382	64,205	19
2-1272	MCMA	FLAT	230		54,148	6,029	34,467	94,644	20
2-1272	MCMA	FLAT	115		989,456	1,262,172		2,251,628	21
1272	MCMA	FLAT	115				1,075,056	1,075,056	22
336	MCMA	FLAT	115	35,000	97,779	18,541		151,320	23
795	MCMA	FLAT	115		336,280	87,643		423,923	24
336	MCMA	FLAT	115		133,111	34,692		167,803	25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
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									42
									43
				864,261	13,567,794	9,502,675	3,181,862	27,116,592	44

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(2) For lines under construction, the following:

a. Commission docket number;
b. Location of end point(s);
c. length;
d. range of right-of-way width;
e. range of tower heights;
f. number of circuits;
g. operating voltage;
h. design capacity;
i. date construction started;
j. projected in-service date;

See following pages

Clinton – Lee Substation 230 kV Line

Project Description: Construct approximately 28 miles of new 230 kV transmission line from the Lee Substation in Wayne County to the Clinton 230 kV Substation in Sampson County.

a. Commission docket number; E-2, Sub 796
b. Location of end point(s); Wayne and Sampson Counties
c. Length; 28 Miles
d. Range of right-of-way width; 100 feet
e. Range of tower heights; 90 – 110 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 628 MVA
i. Estimated date for starting construction; March 2009 (Right-of-way has been cleared)
j. Projected in-service date; June 2010

Trenton Road 230 kV Tap Line

Project Description: Construct approximately 4.3 miles of new 230 kV transmission line from the existing Method – Durham 230 kV Line near the Prison Farm Substation in Wake County to the new Trenton Road 230 kV Substation in Wake County.

a. Commission docket number; E-2, Sub 855
b. Location of end point(s); Wake County
c. Length; 4.3 Miles
d. Range of right-of-way width; 70 feet
e. Range of tower heights; 90 – 140 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 403 MVA
i. Estimated date for starting construction; January 2008
j. Projected in-service date; December 2008

Wadesboro Bowman School 230 kV Tap Line

Project Description: Project consists of constructing a new 230 kV line approximately 13 miles long from the existing Rockingham – West End 230 kV line to the Wadesboro Bowman School 230 kV Substation.

a. Commission docket number; E-2, Sub 870
b. Location of end point(s); Richmond and Anson Counties

c. Length; 13 miles
d. Range of right-of-way width; 100 feet
e. Range of tower heights; 75 - 120 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 628 MVA
i. Estimated date for starting construction; April 2008
j. Projected in-service date; May 2009

(p) Plans for the construction of transmission lines in North Carolina (161 kV and above) shall be incorporated in filings made pursuant to Commission Rule R8-60. In addition, each public utility or person covered by this rule shall provide the following information on an annual basis no later than September 1:

(3) For all other proposed lines, as the information becomes available, the following:

a. county location of end point(s);

b. approximate length;

c. typical right-of-way width for proposed type of line;

d. typical tower height for proposed type of line;

e. number of circuits;

f. operating voltage;

g. design capacity;

h. estimated date for starting construction (if more than 6 month delay from last report, explain); and

i. estimated in-service date (if more than 6-month delay from last report, explain). (NCUC Docket No. E-100, Sub 62, 12/4/92; NCUC Docket No. E-100, Sub 78A, 4/29/98.)

See following pages.

Greenville – Kinston DuPont 230 kV Line

Project Description: Construct approximately 25.3 miles of new 230 kV transmission line from the Greenville 230 kV Substation in Pitt County to the Kinston DuPont 230 kV Substation in Lenoir County.

a. County location of end point(s); Lenoir and Pitt Counties
b. Approximate length; 25.3 Miles
c. Typical right-of-way width for proposed type of line; 100 Feet
d. Typical tower height for proposed type of line; 80 - 120 Feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 628 MVA
h. Estimated date for starting construction; March 2011 (Delayed due to updated load projections)
i. Estimated in-service date; June 2013 (Same as above.)

Cape Fear Plant – Siler City 230 kV Line

Project Description: Construct approximately 30 miles of new 230 kV transmission line from the Cape Fear Plant in Lee County to the Siler City 230/115 kV Substation in Chatham County. NCUC Docket No. E2, Sub 803

a. County location of end point(s); Lee and Chatham Counties
b. Approximate length; 30 Miles
c. Typical right-of-way width for proposed type of line; 100 Feet
d. Typical tower height for proposed type of line; 90 – 120 Feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 628 MVA
h. Estimated date for starting construction; March 2015 (Construction of the Asheboro – DPC Pleasant Garden Line in 2011 allows the delay of this project)
i. Estimated in-service date; June 2017 (Same as above)

Rockingham-West End East 230 kV Line

Project Description: Construct 32 miles of new 230 kV line from the Rockingham 230 kV Substation in Richmond County to the West End 230 kV Substation in Moore County. NCUC Docket No. E2, Sub 933.

a. County location of end point(s); Richmond and Moore Counties
b. Approximate length; 32 miles
c. Typical right-of-way width for proposed line type; 100 feet
d. Typical tower height for proposed type of line; 75 - 110 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design Capacity; 1195 MVA
h. Estimated date for starting construction; July 2009-Clearing, April 2010-Construction
i. Estimated in-service date; June 2011

Asheboro – Pleasant Garden 230 kV Line

Project Description: Construct 22 miles of new 230 kV line from the Asheboro 230 kV Substation in Randolph County to the Duke Power's Pleasant Garden 230 kV Substation in Guilford Counties. NCUC Docket No. E2, Sub 920.

a. County location of end point(s); Randolph (Asheboro) and Guilford (Pleasant Garden)
b. Approximate length; 22 miles
c. Typical right-of-way width for proposed type of line; 100 feet
d. Typical tower height for proposed type of line; 80 feet
e. Number of circuits; 1
f. Operating voltage; 230 kV
g. Design capacity; 1195 MVA
h. Estimated date for starting construction; May 2010
i. Estimated in-service date; June 2011

Harris – Research Triangle Park (RTP) 230kV Line

Project Description: Construct 22 miles of new 230 kV line from the Harris 230 kV Substation in Wake County to the RTP 230 kV Substation in Wake County. The four-mile segment from Amberly Substation to RTP Substation is planned to be in service 6/2009 and built on self-supporting single poles. The remaining construction is planned to be placed in service 6/2011 and consist of: a four-mile segment from Harris Substation to Apex US1 Substation built on H-frame construction; the seven-mile segment from Apex US1 to Green Level Substation is an existing 115 kV line, which will be removed and rebuilt as 230 kV on self-supporting single poles; the remaining seven-mile segment from Green Level Substation to Amberly Substation will be built on self-supporting single poles. NCUC Docket No. E2, Sub 914.

a. County location of end point(s); Wake

b. Approximate length; 22 miles

c. Typical right-of-way width for proposed type of line; 70 feet

d. Typical tower height for proposed type of line; 100 feet

e. Number of circuits; 1

f. Operating voltage; 230 kV

g. Design capacity; 1195 MVA

h. Estimated date for starting construction; July 2010 (Harris – Green Level 230 kV) October 2008 (Amberly-RTP)

i. Estimated in-service date; June 2011 (Harris – Green Level 230 kV) June 2009 (Amberly-RTP)

Rockingham-Lilesville 230 kV Line

Project Description: Construct 14 miles of new 230 kV line from the Rockingham 230 kV Substation in Richmond County to the Lilesville 230 kV Switching Station in Anson County. NCUC Docket No. E2, Sub 922.

a. County location of end point(s); Richmond and Anson Counties

b. Approximate length; 14 miles

c. Typical right-of-way width for proposed line type; 100 feet

d. Typical tower height for proposed type of line; 75 - 110 feet

e. Number of circuits; 1

f. Operating voltage; 230 kV

g. Design Capacity; 1195 MVA

h. Estimated date for starting construction; June 2010

i. Estimated in-service date; June 2011

Richmond-Fort Bragg Woodruff Street 230 kV Line

Project Description: Construct 60 miles of new 230 kV line from the Richmond 500 kV Substation in Richmond County to the Fort Bragg Woodruff Street 230 kV Substation in Cumberland County. NCUC Docket No. E2, Sub 925.

a. County location of end point(s); Richmond and Cumberland Counties

b. Approximate length; 60 miles

c. Typical right-of-way width for proposed line type; 100 feet

d. Typical tower height for proposed type of line; 75 – 110 feet

e. Number of circuits; 1

f. Operating voltage; 230 kV

g. Design Capacity; 1195 MVA

h. Estimated date for starting construction; May 2009

i. Estimated in-service date; June 2011

Discussion of the adequacy of the PEC transmission system.

The PEC transmission system consists of approximately 6,000 miles of 69, 115, 138, 161, 230 and 500 kV transmission lines and just over 100 transmission-class switching stations in its North and South Carolina service areas. PEC has transmission interconnections with Duke Power Company, PJM (via American Electric Power and Dominion Virginia Power), South Carolina Electric & Gas Company, South Carolina Public Service Authority, Tennessee Valley Authority, and Yadkin. The primary purpose of this transmission system is to provide the electrical path necessary to accommodate the transfer of bulk power as required to ensure safe, reliable, and economic service to control area customers.

Transmission planning typically takes into consideration a 10-year planning period. Required engineering, scheduling, and construction lead times can be satisfactorily accommodated within this planning period. Planning is based on PEC's long-range system peak load forecast, which includes all territorial load and contractual obligations; PEC's resource plan; and local area forecasts for retail, wholesale, and industrial loads.

The PEC transmission system is planned to comply with the North American Electric Reliability Council (NERC) Reliability Standards. The Energy Policy Act of 2005 included new federal requirements to create an electric reliability organization (ERO) with enforceable mandatory reliability rules with Federal Energy Regulatory Commission (FERC) oversight. FERC chose NERC to fulfill the role of ERO for the industry. Compliance with the NERC Reliability Standards became mandatory on June 18, 2007 and is enforced by the NERC Regions. PEC's NERC Region is SERC, Inc. (SERC) who annually checks for compliance and conducts detailed audits of standards compliance every three years. The most recent PEC audit, in the spring of 2008, found "no possible violations" of the NERC Reliability Standards.

Planning studies are performed to assess and test the strength and limits of the PEC transmission system to meet its load responsibility and to move bulk power between and among other electrical systems. PEC will study the system impact and facilities requirements of all transmission service requests pursuant to its established procedures.

Transmission planning requires power flow simulations based on detailed system models. PEC participates with neighboring companies in developing and maintaining accurate models of the eastern interconnection. These models include the specific electrical characteristics of transmission equipment such as lines, transformers, relaying equipment, and generators. All significant planned equipment outages, planned inter-company transactions, and operating constraints are included.

The transmission planning process and the generation resource planning process are interrelated. The location and availability of generation additions has significant impacts on the adequacy of the transmission system. Generation additions within the PEC system may help or hinder transmission loading. By planning for both generation needs and transmission needs, PEC is able to minimize costs while maintaining good performance. PEC will interconnect new

generating facilities to the transmission system and will accommodate increases in the generating capacity of existing generation pursuant to its established interconnection procedures.

PEC coordinates its transmission planning and operations with neighboring systems to assure the safety, reliability, and economy of its power system. Coordinated near-term operating studies and longer-range planning studies are made on a regular basis to ensure that transmission capacity will continue to be adequate. These studies involve representatives from the Virginia-Carolinas Subregion (VACAR) and adjacent subregions and regions to provide interregional coordination. For intra-regional studies, PEC actively participates on the Intra-regional Long-term Power Flow Study Group (LT-PFSG), the Intra-regional Near-term Power Flow Study Group (NT-PFSG), and the VACAR reliability committees. For inter-regional studies PEC actively participates on the Eastern Interconnection Reliability Assessment Group (ERAG). PEC has participated in development efforts for a potential RTO in the southeast and is continuing to follow requirements in this area.

The system is planned to ensure that no equipment overloads and that adequate voltage is maintained. The most stressful scenario is typically at peak load with certain equipment out of service. A thorough screening process is used to analyze the impact of potential equipment failures or other disturbances. As problems are identified, solutions are developed and evaluated.

In addition, PEC, Duke, NCEMPA and NCEMC are engaged in a collaborative transmission planning process (the NC Transmission Planning Collaborative). This effort allows NCEMPA and NCEMC to participate in all stages of the transmission planning process, resulting in Duke and PEC moving towards a single collaborative transmission plan for their control areas, and a plan designed to address both reliability and market access.

PEC's transmission system is expected to remain adequate to continue to provide reliable service to its native load and firm transmission customers.

Progress Energy

Progress Energy Carolinas Integrated Resource Plan

Appendix H
Short Term Action Plan

September 1, 2008

PEC Short Term Action Plan Summary

The following activities are underway as part of the near-term implementation of the Company's Integrated Resource Plan.

Near Term, Known Resource Additions

1. Wayne County CT – 06/2009, construction is under way.
2. Richmond County CC – 06/2011, Certificate of Public Convenience and Necessity hearing scheduled for September 3, 2008.
3. Miscellaneous unit uprates (see 2008 IRP)

Proposed DSM and EE – In addition to existing DSM and EE programs, PEC has filed for NC Commission approval for the following programs:

1. Distribution System Demand Response (DSDR)
2. Residential EnergyWise
3. Home Advantage New Construction Program
4. Commercial, Industrial, and Governmental (CIG) New Construction Program
5. Commercial, Industrial, and Governmental (CIG) Comprehensive Retrofit Program

Once approvals are obtained, final program development will proceed and the programs will be implemented.

Additional program development is ongoing.

Alternative Supply Resources (Incremental Renewables)

1. Name is confidential – 40 MW, base load, 01/2012
2. Coastal Carolina Clean Power 24.9 MW, base load, wood biomass, 01/2009

Negotiations for other projects are ongoing.

For more detail on all of these ongoing activities, please see PEC's 2008 IRP.