Progress Energy Carolinas

Integrated Resource Plan

November 2012

Public Service Commission of South Carolina
Docket No. 2012-8-E

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Appendices

Overview

This document is Progress Energy Carolinas, Inc.'s ("the Company" or "PEC") 2012 Integrated Resource Plan (IRP). It reflects current forecasts and management approved changes to resources. In general the majority of the nearer term supply-side and demand-side additions have both management approval and North Carolina Utilities Commission (NCUC) and/or Public Service Commission of South Carolina (PSCSC) approval, as appropriate, while the longer term portion of the plan represents forecasts of undesignated resources that are still subject to both internal approval and regulatory review.

On July 2, 2012, Progress Energy was acquired by Duke Energy. At that point in time the development of the 2012 IRPs were well under way for both companies with each company using its own input assumptions and analytic tools. It should be noted that the development of an integrated resource plan involves hundreds of inputs that are used within a complex analytic framework. Furthermore, the development of an IRP involves input and analysis from several organizations throughout the company. A significant portion of this data is proprietary and could not be shared prior to the closing of the merger. In addition, while both companies use industry accepted analytic approaches and models, several differences exist between the companies. While it is the intent of both Duke Energy Carolinas (DEC) and PEC to standardize data inputs and models for use in their individual IRP filings it was not possible to accomplish such reconciliation in time for the 2012 filing. As such, this IRP has been developed using planning assumptions and analytic tools and methods that are unique to PEC's legacy approach as a stand-alone company. As more coordinated planning occurs over time, future IRPs will reflect the effects of coordinated assumptions and analytic approaches between DEC and PEC.

As stated in previous resource plans several external challenges persist from a resource planning perspective. These challenges include market based uncertainties such as significant fuel price volatility, tremendous economic uncertainty, and customer behavior and usage changes. In addition to market uncertainty, several existing and potential regulatory actions also present challenges to the planning process. These include potential federal environmental legislation dealing with regulation of carbon emissions including proposed Greenhouse Gas (GHG) New Source Performance Standards (NSPS), proposals for Federal renewable portfolio standards, the Environmental Protection Agency's (EPA) new Cross State Air Pollution Rule (CSAPR), the EPA Maximum Achievable Control Technology (MACT) rule (also known as the Mercury and Air Toxics Standards or MATS rule), the expected EPA 316b rule, and the potential consideration of coal ash as hazardous waste by EPA.

Over the past several years many of these factors, paired with lower natural gas prices, led to the Company's decision to retire three coal units at both of its Lee and Sutton facilities and construct new state-of-the-art efficient natural gas combined cycle units in their place. Beyond these two facilities, PEC also committed to retire its five remaining North Carolina unscrubbed coal units at the Weatherspoon and Cape Fear sites as part of the Company's Coal Retirement Plan approved by the North Carolina Utilities Commission. The Company announced on July 27, 2012 plans to retire its one remaining unscrubbed coal plant, its South Carolina Robinson Unit 1. Also, the Company announced it had accelerated the retirement of Cape Fear units 5 and 6 to October, 2012. As a cumulative result of the new gas-fired combined cycles being constructed at the Lee and Sutton sites and the associated retirement of twelve coal units at the Lee, Sutton, Weatherspoon, Robinson, and Cape Fear sites, the Company will have replaced approximately 1,620 MW of unscrubbed coal generation with approximately 1,545 MW of state-of-the-art natural gas-fired generation. Benefits of this portfolio modernization include both environmental benefits, in the form of significant reductions in the output of SO_2, NOx, mercury and CO_2, as well as fuel diversification benefits resulting from the addition of the new gas-fired generation.

In addition to gas-fired generation additions, ongoing efforts represented in the 2012 IRP include significant commitments to alternative sources of energy and capacity, as well as demand-side resource options. Since 2008 PEC has been actively developing and implementing new demand-side management (DSM) and energy efficiency (EE) programs throughout its North Carolina and South Carolina service areas aimed at helping all customer classes and market segments reduce electricity usage. For example, PEC's current program portfolio, as shown below, was designed to provide a comprehensive set of energy savings measures that would be accessible to virtually every customer.

Residential Programs

- Home Energy Improvement – encourages energy efficiency upgrades in existing homes
- New Construction – promotes the building of energy efficient new homes
- Neighborhood Energy Saver – a no-cost direct install program for low-income customers
- Lighting – provides in-store discounts on a variety of high-efficiency CFL bulbs
- Appliance Recycling – promotes removal/recycling of older refrigerators and freezers
- Energy Efficient Benchmarking – encourages energy efficiency actions and behaviors by providing reports with energy usage comparisons and savings recommendations
- Residential EnergyWise Home^{SM} – residential direct load control
- Prepay Pilot Program (*South Carolina only*) – evaluates the energy efficiency potential associated with prepaid electric service.

Non-Residential Programs

- Commercial, Industrial, and Governmental (CIG) Energy Efficiency – offers prescriptive and custom measures in both the retrofit and new construction markets
- Small Business Energy Saver (*Approved in South Carolina only as of August 1, 2012*) – a direct install program for small hard-to reach business customers under 100 kW.
- CIG Demand Response Automation – non-residential direct load control

Smart Grid

- Distribution System Demand Response – smart grid upgrades to the distribution system that can be used to reduce system peak loads and line losses.

PEC also offers several educational initiatives designed to increase consumer knowledge and awareness regarding energy efficiency opportunities. All of these investments are essential to building large-scale, long-term customer participation in energy efficiency programs and, ultimately, reducing the need for supply-side resources. PEC's DSM and EE programs provide substantial energy and demand contributions to the resource plan. They account for approximately 20% of the expected energy growth and 25% of the expected demand growth over the 2013 through 2027 study period. By the end of the 15-year planning horizon PEC projects that its DSM/EE portfolio of programs will provide over 1,400 MW of peak load reduction and over 3.18 billion kWh in energy savings.

With respect to baseload carbon-free generation, new nuclear generation continues to be an important component of PEC's resource plan. The 2012 IRP continues to contemplate the potential for regional partnerships rather than full ownership of a nuclear facility. In its 2011

IRP PEC showed a generic ownership of a 25% stake of a two unit site but did not align the timing of such ownership directly with a specific project(s). Solely for resource planning purposes, the 2012 IRP assumes that PEC would take a five percent share of SCANA's V.C. Summer Units and 20 percent share of DEC's Lee units as represented in their respective 2011 IRPs. Under this regional assumption, nuclear projects would be jointly undertaken by utilities in the region with participating utilities and load serving organizations taking ownership stakes in each other's projects. At this point in time, no specific contractual arrangements have been entered into and as such the nuclear blocks shown in the IRP simply represent baseload generation blocks that align with existing regional projects in order to assess the ongoing viability of regional nuclear within the integrated resource plan. The exact timing and amount of ownership in a regional partnership will depend on the specific project and future contractual negotiations, which may result in adjustments of both timing and volume of new nuclear generation placed into the resource plan. Under the assumptions used in the 2012 IRP for future carbon legislation, carbon dioxide limits would continue to ramp down significantly beyond the study period. Such an outcome would likely require additional nuclear generation after 2027 to meet declining CO_2 targets.

The Company continually evaluates possible changes to its resource plan. These changes include, but are not limited to, further investments in energy efficiency, construction or purchase of additional renewable resources, and investment in regional nuclear generation. If one or more of these changes are made, the current proposed fossil resource additions will change as well. Obviously, the further out in time a resource addition is scheduled to occur, the greater its uncertainty. As economic, legislative and market conditions continue to unfold, the Company will adjust its IRP accordingly.

In summary, this IRP includes a balanced mix of additional DSM and EE, renewable energy, purchased power, combustion-turbine generation, combined cycle generation, and nuclear generation. This approach helps ensure electricity remains available, reliable and affordable, and is produced in an environmentally sound manner. This diversified approach also helps to insulate customers from price volatility with respect to any one particular fuel source.

Included in this document is a 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

PEC's forecasting processes have utilized econometric and statistical methods since the mid-1970s. 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 that 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 found later in this section. 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 1.6% across the forecast period before subtracting for DSM, which is equal to the customer growth rate of 1.6%. The retail demand growth rate drops to 1.2% after adjusting for DSM.

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 such as we have seen with the current extended economic downturn. 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 following table contains ten years of historical and 16 years of forecasted customer data.

	Average Annual Customers			
	Residential	Commercial	Industrial	Total
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	1,229,119	218,279	4,241	1,451,639
2009	1,240,626	217,447	4,625*	1,462,698
2010	1,249,815	218,296	4,556	1,472,667
2011	1,255,184	219,076	4,511	1,478,770
2012	1,265,184	223,802	4,511	1,493,496
2013	1,277,684	226,076	4,511	1,508,271
2014	1,292,184	228,398	4,511	1,525,093
2015	1,310,684	232,123	4,511	1,547,318
2016	1,345,571	237,160	4,511	1,587,242
2017	1,378,071	242,850	4,511	1,625,432
2018	1,407,089	248,701	4,511	1,660,301
2019	1,424,409	254,035	4,511	1,682,955
2020	1,446,737	258,930	4,511	1,710,178
2021	1,467,538	263,032	4,511	1,735,081
2022	1,488,343	267,188	4,511	1,760,042
2023	1,508,628	271,176	4,511	1,784,315
2024	1,528,988	275,358	4,511	1,808,857
2025	1,548,950	279,101	4,511	1,832,562
2026	1,568,950	283,161	4,511	1,856,622
2027	1,588,616	287,227	4,511	1,880,354

* PEC undertook a review of its Standard Industrial Classification and revenue classifications for all accounts in December 2008 to ensure the assignments were appropriate. A significant number of small usage commercial accounts were re-classified as industrial accounts during this effort; therefore, the number of industrial accounts increased significantly, while the overall industrial demand and energy sales were only slightly impacted.

The next table reflects ten years of historical energy sales to the retail classes.

Retail Sales MWh – Actual

	Residential	Commercial	Industrial	Military & Street Light
2002	15,238,554	12,467,562	13,088,615	1,437,060
2003	15,282,872	12,556,905	12,748,754	1,407,807
2004	16,003,184	13,018,688	13,036,419	1,431,447
2005	16,663,782	13,314,324	12,741,342	1,409,801
2006	16,258,675	13,358,042	12,415,862	1,418,750
2007	17,199,511	14,033,008	11,882,660	1,437,590
2008	16,999,685	13,939,902	11,215,507	1,466,531
2009	17,117,480	13,639,299	10,374,623	1,496,904
2010	19,108,178	14,184,282	10,676,800	1,574,405
2011	17,764,005	13,708,715	10,573,118	1,591,058

This final customer data table contains forecasted system energy sales for 16 years.

System Sales MWh – Projected

	Residential	Commercial	Industrial	Military & Street Light	Retail Losses + Co. Use	Wholesale	Firm (DEC Firm & Mitigation Sales)	EE & DR Reductions System	PEC System Including PEC Firm Reduced By EE & DSM
2012	17,856,560	13,862,995	10,609,649	1,604,024	2,197,916	17,786,622	986,152	474,311	64,429,606
2013	18,038,013	14,119,741	10,715,746	1,631,325	2,226,518	18,935,802	1,046,544	647,576	66,066,112
2014	18,223,320	14,446,907	10,822,904	1,658,638	2,258,882	19,180,364	1,046,814	816,513	66,821,316
2015	18,520,521	14,696,772	10,866,194	1,666,032	2,288,815	19,408,110	127,099	998,127	66,575,415
2016	18,922,393	15,063,304	10,909,106	1,673,462	2,329,795	19,685,977	126,323	1,190,332	67,520,029
2017	19,376,356	15,304,317	10,952,191	1,680,930	2,367,098	19,869,159	127,432	1,344,018	68,333,466
2018	19,843,241	15,495,761	10,995,447	1,688,436	2,402,575	19,990,936	126,766	1,518,811	69,024,352
2019	20,268,789	15,746,968	11,038,877	1,695,980	2,438,984	20,264,598	126,170	1,713,379	69,866,986
2020	20,659,331	16,013,988	11,082,480	1,703,561	2,474,443	20,429,477	126,205	1,920,706	70,568,780
2021	20,986,664	16,289,586	11,126,258	1,711,181	2,507,178	20,622,098	126,231	2,134,878	71,234,318
2022	21,318,269	16,592,091	11,170,211	1,718,839	2,541,484	20,854,994	126,427	2,342,191	71,980,124
2023	21,636,411	16,894,405	11,214,340	1,726,537	2,575,117	21,097,066	127,600	2,542,534	72,728,941
2024	21,970,126	17,200,773	11,236,370	1,734,273	2,608,629	21,416,491	126,707	2,735,114	73,558,256
2025	22,268,734	17,509,177	11,258,625	1,742,048	2,640,499	21,641,083	0	2,888,530	74,171,636
2026	22,592,649	17,889,346	11,280,891	1,749,863	2,677,227	21,926,028	0	3,026,108	75,089,897
2027	22,917,102	18,274,557	11,303,101	1,757,718	2,714,234	22,204,745	0	3,146,568	76,024,889

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 is considered to determine if the technology meets PEC's particular generation requirements and whether it will integrate well into the PEC system. The evaluation of technical feasibility includes the size, fuel type, and construction requirements of the particular technology and the ability to match the technology to the service it will be required to perform on 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, is 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 are based on EIA's 2012 Annual Energy Outlook report and on internal PEC resources. Busbar curves are useful for comparing costs of resource types at various capacity factors but cannot be utilized for determining a long term resource plan because future units must be optimized with an existing system containing various resource types.

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 are reviewed as potential resource options include 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
Onshore Wind
Pulverized Coal (PC)

<u>Demonstrated Technologies</u>
Biomass
Integrated (Coal) Gasification/Combined Cycle (IGCC)
Nuclear Advanced Light Water Reactor (ALWR)
Municipal Solid Waste-Landfill Gas (MSW-LFG)
Solar Photovoltaic (PV)

<u>Emerging Technologies</u>
Fuel Cell (FC)
Offshore Wind

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, the more uncertain and less accurate its cost estimate.

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, 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 is 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, 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 is partnering with the University of NC at Chapel Hill on a study to fully map and model NC's viable offshore wind resources. The three-year research study will measure wind speeds in areas for which there is currently no data, create a refined wind resource map, and develop an atmospheric modeling system to enable improved wind forecasting capabilities. This study is expected to be the most comprehensive analysis to date on NC's capability to support offshore wind energy generation and will help utility, state and local decision makers determine how best to pursue offshore wind power while still providing cost-effective and reliable electricity to customers.

Solar photovoltaic (PV) projects are technically constrained from achieving high capacity factors. In the southeast, they are expected to operate at a capacity factor of approximately 25%, making them unsuitable for intermediate or baseload duty cycles. PV projects, 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 without state and federal subsidies. 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. PEC has aggressively pursued solar contracts to meet requirements of North Carolina Senate Bill 3. Through these solar contracts, PEC is well positioned to meet the North Carolina Senate Bill 3 solar requirements. In South Carolina, the premiums provided by Palmetto Clean Energy (PaCE) also encourage the installation of small customer-owned solar photovoltaic systems.

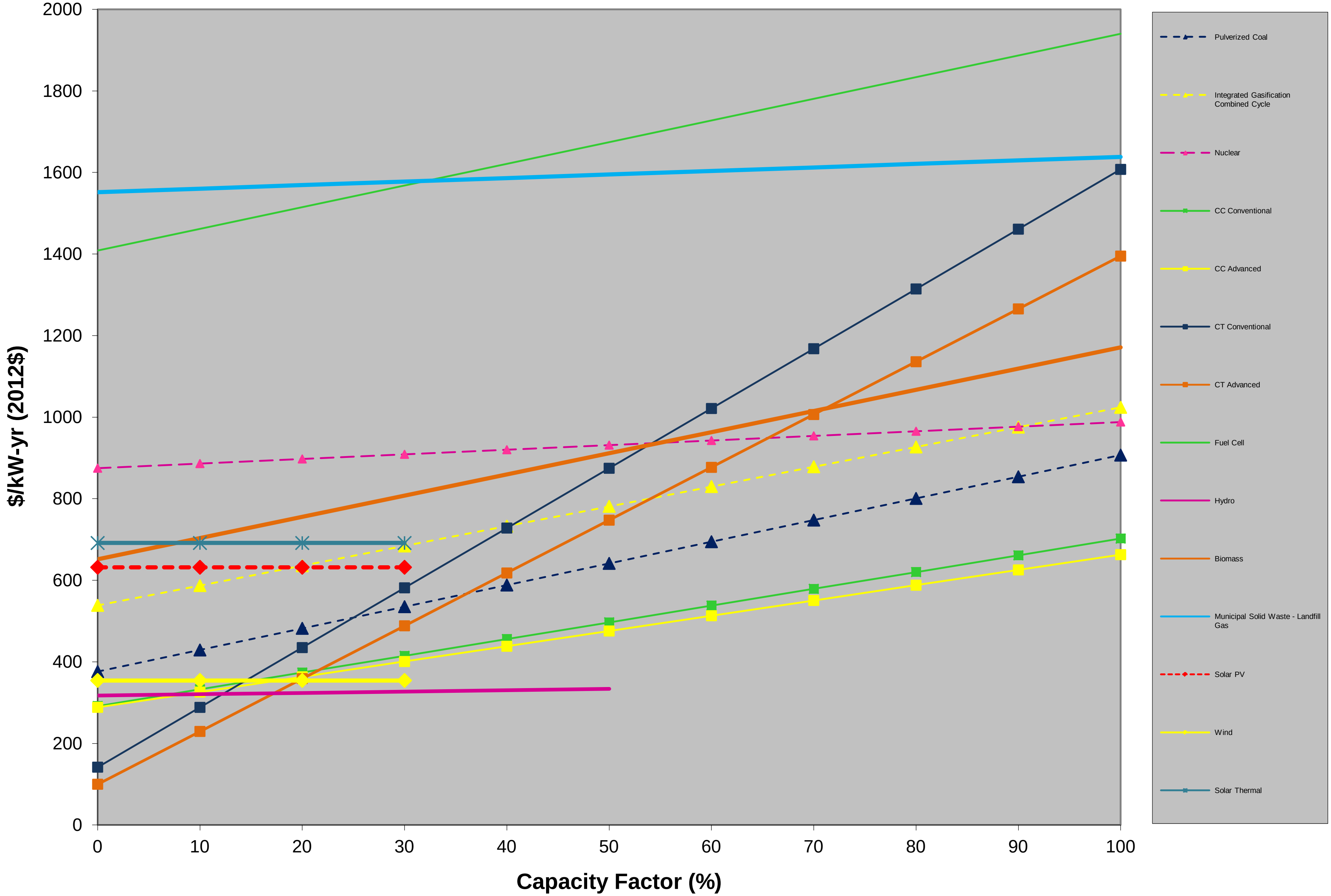
The capacity value of wind and solar resources depends heavily on the correlation between the system load profile, wind speed, and solar insolation. A Utility Wind Integration Group report noted that the capacity value of wind is typically less than 40% of nameplate capacity. Although wind and solar projects are currently not viable options for making significant contributions to *reserve* requirements due to their relatively high cost and intermittent 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. While these purchase contracts are targeted at adding renewable energy to PEC's portfolio, a limited number of these renewable resources also provide capacity to the resource plan. The IRP Tables 1 and 2 detail the current and future 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.

While this IRP and the REPS Compliance Plan incorporate resources for meeting the requirements of North Carolina Senate Bill 3, PEC has not incorporated additional resources that may be needed in the future for meeting the requirements of potential federal legislation. The type and timing of additional renewable resources will depend heavily on federal legislation being passed and implementation rules being established.

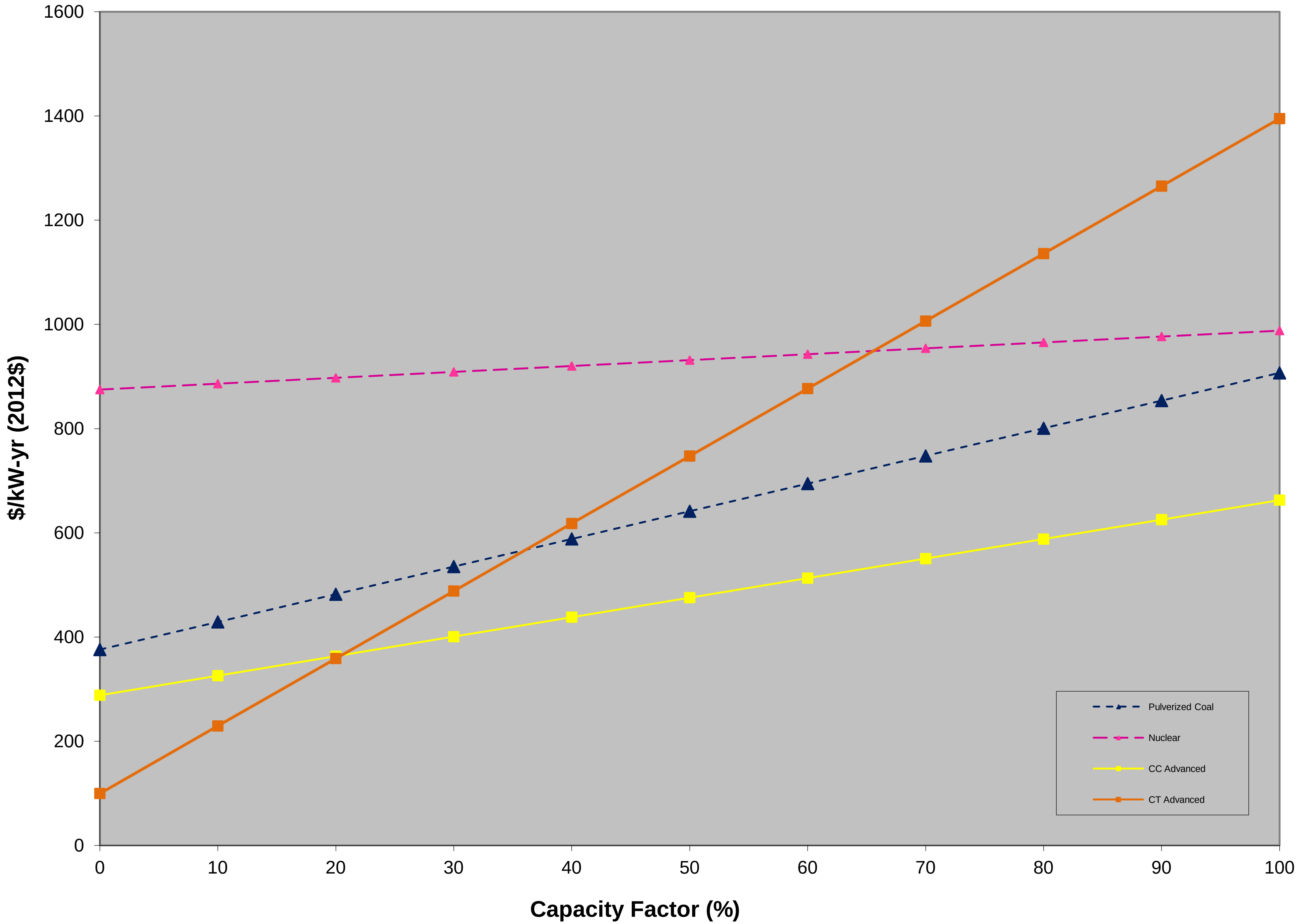
Figures 1-1 and 1-3 provide an economic comparison of all technologies examined based on generic capital, operating, and fuel cost projections without and with carbon costs. Figures 1-2 and 1-4 show the most economical and viable utility scale technologies without and with carbon costs. For the most economic utility scale supply-side technologies in Figure 1-4, more detailed economic and site specific information is developed for inclusion in the resource plan evaluation process. These technologies include simple-cycle combustion turbine, combined cycle, pulverized coal, and nuclear.

Figure 1-1
Levelized Busbar Cost for All Technologies Without Carbon



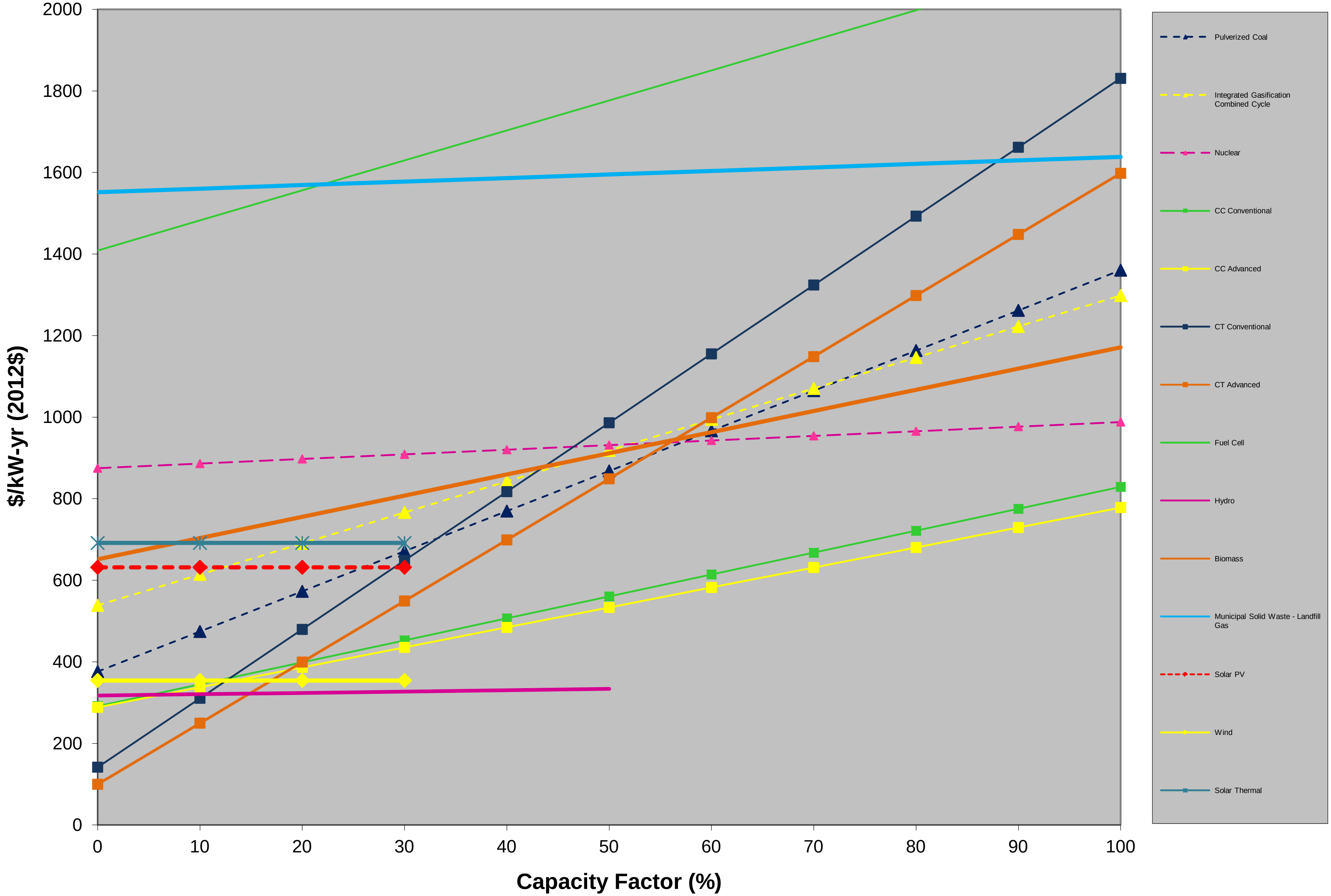
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission or other site specific criteria.

Figure 1-2
Levelized Busbar Cost for Utility Scale Technologies Without Carbon



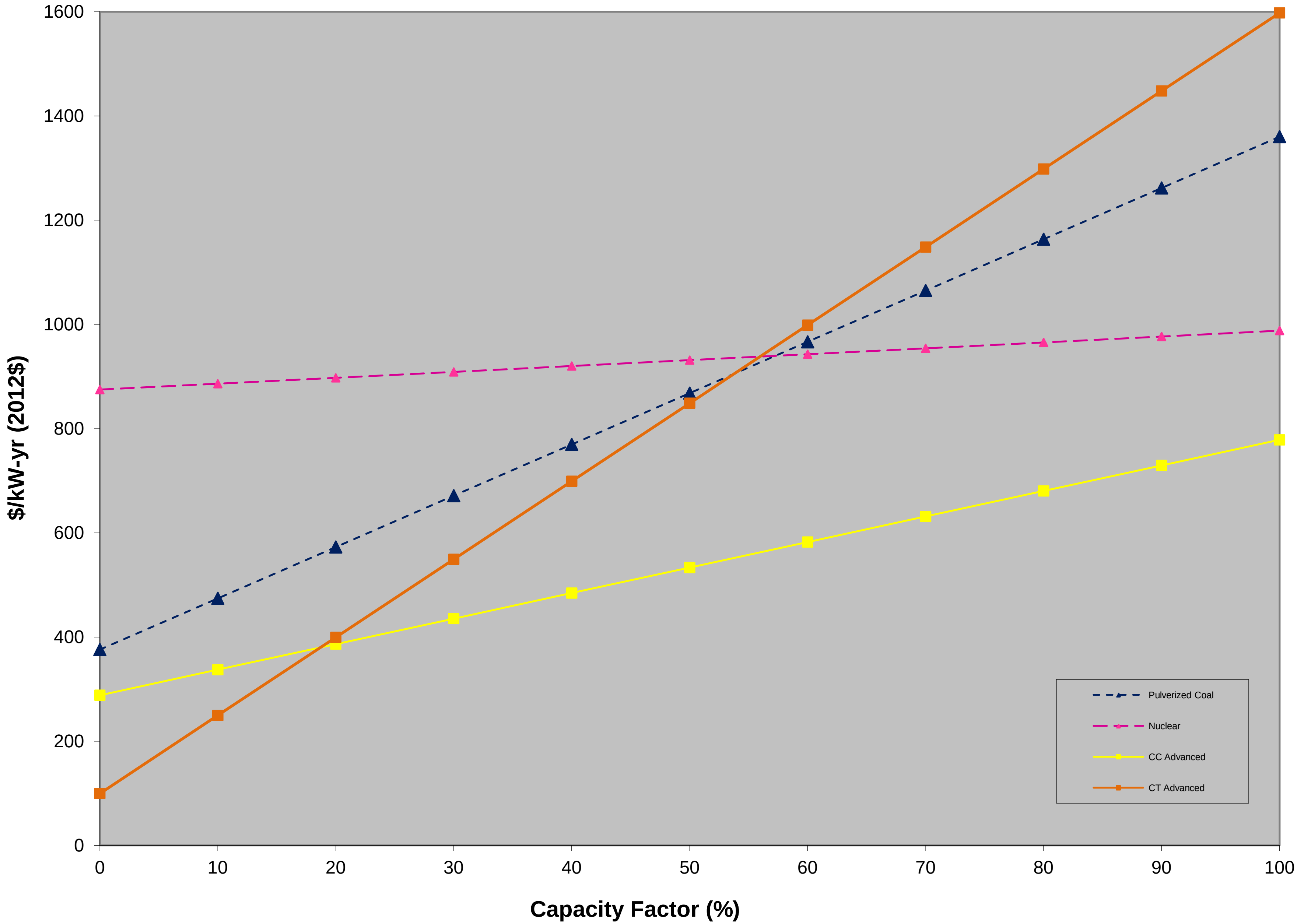
NOTE: The graph above is based on generic capital, O&M, and delivered fuel costs data but without transmission or other site specific criteria.

Figure 1-3
Levelized Busbar Cost for All Technologies With Carbon



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 1-4
Levelized Busbar Cost for Utility Scale Technologies With Carbon



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 (SB 3) was signed into law, establishing a renewable energy and energy efficiency portfolio standard (REPS). In accordance with the bill, the state's electric utilities must purchase or generate 3 percent of their energy (based on the prior year's total retail sales) from renewable resources in 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 solar, swine, and poultry waste requirements for the state of NC are as follows:

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 all 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 has issued multiple RFP's for various renewable power supply technologies since November 2, 2007. In addition, PEC currently maintains an open RFP for non-solar projects that are 10 MW or less. Through the RFP process, PEC has executed numerous contracts to ensure compliance with the requirements of SB 3. To select the projects that provide the most cost-effective means for meeting SB 3 requirements, renewable bids received are evaluated against each other, the market, how each project fits within the near-term and long-term REPS compliance plan, and how each project impacts the annual cost cap limitations. The REPS compliance plan is detailed in Appendix D. IRP Tables 1 and 2 reflect committed renewables only, given the uncertainty associated with the undesignated renewables that will be needed for compliance with North Carolina REPs standards.

Demand Side Management and Energy Efficiency

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.

Since 2008 PEC has been actively developing and implementing new DSM and EE programs throughout its North Carolina and South Carolina service areas to help customers reduce their electricity demands. PEC's DSM and EE plan was designed to be flexible, with programs being 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 are aimed at helping all customer classes and market segments use energy more wisely.

PEC is also evaluating the potential for new technologies and new delivery options on an ongoing basis to ensure delivery of comprehensive programs in the most cost effective way. PEC will continue to 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. In order to determine cost effectiveness, PEC primarily relies upon the Total Resource Cost Test to evaluate energy efficiency programs, and uses the Rate Impact Measure test to evaluate DSM programs. PEC currently has approval from the NCUC and PSCSC to offer a large variety of DSM and EE programs and measures to help reduce electricity consumption across all types of customers and end-uses.

PEC also offers several educational initiatives aimed at increasing consumer awareness around energy efficiency, including the Customized Home Energy Report. This tool allows residential customers to conduct a self-audit by simply answering a series of questions about their home. Once the assessment is completed, the customer receives a custom four-page summary that provides a billing history, tips towards saving energy that are specific to the customer, and a list of DSM/EE programs that the customer may be able to use to help them save energy.

All of these investments are essential to building customer awareness about energy efficiency and, ultimately, reducing energy resource needs by driving large-scale, long-term participation in efficiency programs. Significant and sustained customer participation is critical to the success of PEC's DSM/EE programs. To support this effort, PEC has focused on planning and implementing programs that work well with customer lifestyles, expectations and business needs.

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. See Appendix E for further detail on PEC's DSM, EE and consumer education programs.

Reliability Criteria

As part of the NCUC's approval of the 2010 IRP, Progress Energy Carolinas and Duke Energy Carolinas were ordered to perform quantitative reserve margin analyses and provide results of the analyses in the companies' 2012 IRPs. PEC obtained the services of Astrape Consulting for conducting the resource adequacy analysis. Following is a discussion of PEC's reliability planning practices and findings from the Astrape study.

Background

The reliability of energy service is a primary input in the development of the resource plan. Utilities require a margin of generating capacity reserve 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 reserve capacity that is appropriate for all systems since these characteristics are particular to each individual utility.

PEC periodically 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 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 is a widely accepted criterion for establishing generation system reliability. PEC uses a target reliability of one day in 10 years LOLE for generation reliability assessments. LOLE indicates the expected number of capacity deficient condition events that 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 reserve margin or capacity margin, for use as targets in developing the resource plan.

Since the mid-1990's, PEC's reliability assessments have demonstrated that a minimum capacity margin target of approximately 11-13% satisfies the one day in 10 year LOLE criterion and provides an adequate level of reliability to its customers. PEC has considered an 11% capacity margin to be a minimum and may be acceptable in the near term when there is greater certainty in forecasts. PEC has used a minimum capacity margin target of 12-13% in the longer term to provide an extra margin of reserves to compensate for possible load forecast uncertainty, uncertainty in DSM/EE forecasts, or delays in bringing new capacity additions on-line.

Astrape Reserve Margin Analysis

Astrape Consulting is an energy consulting firm with a focus on resource adequacy and resource planning. Astrape conducted a detailed resource adequacy assessment for PEC in 2012 that incorporated the uncertainty of weather, economic load growth, unit availability, and transmission availability for emergency tie assistance. Astrape analyzed the optimal planning reserve margin for PEC based on providing an acceptable level of physical reliability and minimizing economic costs to customers.

From a physical reliability perspective, LOLE decreases as reserve margin increases. As previously mentioned, the most common physical metric used in the industry is to target a system reserve margin that meets the one day in 10 year standard which is interpreted as one firm load shed event every 10 years. This results in unserved energy for a firm customer. Based on the Astrape analysis, a 14.5% reserve margin satisfies the one day in 10 year LOLE metric.

From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. Similarly, as planning reserve margin decreases, the cost of reserves decreases while the costs related to reliability events increases, including the costs to customers of loss of power. Thus, there is an economic optimum point where the cost of additional reserves plus the cost of reliability events to customers is minimized. The Astrape study shows that the optimal reserve margin that minimizes the cost to customers on a long term basis is 15.5%. Astrape notes that there is not a significant cost impact of being slightly above the minimum cost point and thus recommends a target reserve margin range of 14.5-17.0%.

Astrape Recommendations

Astrape recommends that PEC set its minimum reserve margin at 14.5% consistent with the one day in ten year LOLE metric. Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the minimum. The study demonstrates that a target reserve margin in the range of 14.5-17.0% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as nuclear or coal or even combined cycle, the reserve margin would likely rise above the top end of the reserve margin range at 17%. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin range of 14.5-17.0% should not be considered absolute; resource decisions should be made on a case-by-case basis.

Reserve Margin versus Capacity Margin

PEC has historically expressed its reserve requirement in terms of capacity margin. Capacity margin is defined as resources minus demand, divided by resources. Similarly, reserve margin is defined as resources minus demand, divided by demand. Beginning with the 2012 IRP, PEC will now incorporate reserve margin as its reserve metric. Note that changing the reserve metric from capacity margin to reserve margin only reflects a change in convention and does not impact the analytics involved in conducting reliability assessments.

Capacity Margin = (Resources – Demand) / Resources
Reserve Margin = (Resources – Demand) / Demand

As previously stated, PEC has utilized a minimum capacity margin target in the range of 11-13% with the upper end of the range used for longer term planning to account for greater uncertainty in forecasts. Results from the Astrape study are expressed in terms of reserve margin values and showed that PEC should maintain its minimum reserve margin at 14.5% to satisfy the one day in 10 year LOLE criterion. The table below provides reserve margin and corresponding capacity margin values from the Astrape analysis to allow comparison of Astrape results to PEC's prior minimum capacity margin target.

	LOLE: 1 Day in 10 Years	Target Range
Reserve Margin (%)	14.5	14.5 – 17.0
Capacity Margin (%)	12.7	12.7 – 14.5

Based on the one day in 10 year LOLE criterion, the table above shows that PEC's longer term capacity margin range of 12-13% is consistent with the Astrape recommended 14.5% reserve margin (which corresponds to a 12.7% capacity margin). Based on results of the Astrape reserve margin analysis and consistent with prior internal LOLE analyses, PEC is adopting a minimum target reserve margin of 14.5% with a target range of 14.5-17.0% which recognizes the economic benefits to customers of being above the 14.5% minimum target.

Adequacy of Projected Reserves

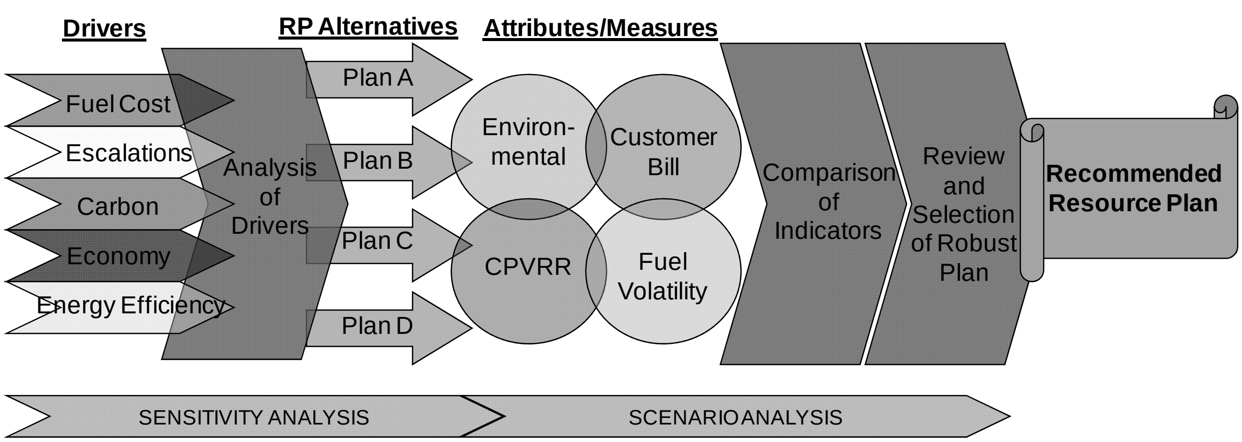
PEC's resource plan reflects reserve margins ranging from 15-18%. Reserves projected in PEC's IRP meet the minimum reserve margin target and thus satisfy the one day in 10 year LOLE criterion. Projected reserve margins exceed the target range by only 1% in years 2015 and 2020. Reserves projected in PEC's IRP are appropriate for providing an adequate and reliable power supply.

Resource Plan Evaluation and Development

The objective of the resource planning process is to create a robust plan. While the type of analysis illustrated in Figures 1-1 through 1-4 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 process that takes into consideration numerous factors, both current and future, related to issues such as customer rates, fuel costs, renewables, environmental requirements and unknowns, demand-side management, energy efficiency, potential technology shifts, load and energy changes, and capital costs of new supply side resources. 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 of the Company's 2012 IRP discusses the process to develop the robust resource plan in detail. The resource planning process can be seen in a simplistic format in Figure 2 below.

Figure 2 Integrated Resource Planning Process Flowchart



The sensitivity analysis is based on the expertise of 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 significantly change the plan.

The scenario analysis contemplates and develops future states that bound the potential outcomes of the key drivers such as load, energy, construction cost escalations, fuel costs, and carbon costs. The alternative plans that are developed based on the sensitivity analysis are then tested in each scenario. By testing each of these alternative plans in each of the scenarios, how each of the plans fares in each scenario and in aggregate to all scenarios can be determined. The ranking of each plan in each scenario is performed using key attributes in the categories of customer cost and environmental performance. 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 wide range of events. This is why different scenarios of fuel price escalation, construction cost escalation, and environmental costs, are taken into consideration when testing the plans to determine robustness.

Assessment of Purchased Power Alternatives

Because the goal of the IRP process is to meet customer needs for a reliable supply of electricity at the lowest reasonable cost, the plan that has been identified as the preferred plan then serves as a benchmark against which purchased power opportunities are measured. Before proceeding with a self-build option, it must be determined whether there are any purchased power alternatives available that would maintain the system reliability level in a more cost-effective manner.

PEC constantly studies, tracks and evaluates the costs of new generation and the market price for purchased power. For self build options PEC utilizes a competitive bidding process for equipment, engineering and construction services when seeking to build new generation. PEC requests proposals from a range of qualified and creditworthy contractors with proven experience in utility scale generation projects. For power purchases, depending on the circumstances PEC will then utilize a formal or informal RFP to evaluate the feasibility of purchasing equivalent generation resources from the wholesale market. PEC evaluates the cost, reliability, flexibility, environmental impacts, risk factors, and various operational considerations in determining the optimal resource addition for a given situation. As a general policy, PEC solicits the wholesale market before making resource decisions. PEC incorporates by reference its more detailed discussion of its purchased power methodology filed in Docket No. E-100, Sub 118 on August 31, 2009.

IRP Tables and Plan Discussion

PEC's 2012 Annual IRP as presented in Tables 1 and 2 includes 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 DSM, EE and renewables programs to comply with Senate Bill 3 and meet its least cost planning obligation. 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 prior to 2027. At this time, though, no definitive decision has been made to construct new nuclear plants.

In the near term, the current resource plan utilizes gas-fired generators for baseload and intermediate needs, and gas- 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, intermediate, and base 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 renewals for some of its existing hydro plants.

The 2012 resource plan includes the following planned capacity additions:

Name	Capacity (MW)	Type	In-Service date
Wayne County CC	920	CC	01/13
Sutton CC	625	CC	12/13
Undesignated	126	CT	12/16
Undesignated	55	Reg. Nuclear	03/17
Undesignated	370	CT	06/18
Undesignated	55	Reg. Nuclear	01/19
Undesignated	185	CT	06/19
Undesignated	787	CC	06/20
Undesignated	221	Reg. Nuclear	06/21
Undesignated	787	CC	06/22
Undesignated	221	Reg. Nuclear	06/23
Undesignated	185	CT	06/26
Undesignated	185	CT	06/27

On October 22, 2009, the NCUC granted PEC a Certificate of Public Convenience and Necessity (CPCN) to construct the Wayne County CC. The Wayne County CC is currently on schedule to meet its January 2013 commercial operation date. The NCUC granted PEC a certificate for construction of the Sutton CC on June 9, 2010. The Sutton CC is currently on schedule to meet its December 2013 commercial operation date.

Regarding the undesignated capacity additions mentioned above, PEC will adhere to its purchase power assessment procedure outlined above. Because these potential additions are so far into the future, and therefore somewhat uncertain, PEC's assessment of purchase power options has not yet been conducted. However, this assessment will be conducted, and the results included in PEC's application for a CPCN, should the decision be made to proceed with these additions.

Progress Energy Carolinas

Table 1 2012 Annual IRP (Summer)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
GENERATION CHANGES															
Sited Additions	920	625													
Undesignated Additions (1)					181	370	240	787	221	787	221			185	185
Planned Project Uprates	23	9	24												
Retirements	(973)	(575)													
INSTALLED GENERATION															
Nuclear	3,540	3,549	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573
Fossil	4,095	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520
Combined Cycle	2,027	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652
Combustion Turbine	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087
Hydro	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Undesignated (1)					181	551	791	1,578	1,799	2,586	2,807	2,807	2,807	2,992	3,177
TOTAL INSTALLED	**12,974**	**13,033**	**13,057**	**13,057**	**13,238**	**13,608**	**13,848**	**14,635**	**14,856**	**15,643**	**15,864**	**15,864**	**15,864**	**16,049**	**16,234**
PURCHASES & OTHER RESOURCES															
SEPA	95	109	109	109	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
NUG QF - Renewable	236	236	234	268	268	220	221	221	208	205	207	207	207	207	210
Butler Warner	220	220	220	220	220										
Anson CT Tolling Purchase	336	336	336	336	336	336	336	336	336	336	336	336	336	336	336
Hamlet CT Tolling Purchase	112	168	168	168	168	168									
Broad River CT	807	807	807	807	807	807	807	807	329						
Southern CC Purchase - LT	145	145	145	145	145	145	145								
TOTAL SUPPLY RESOURCES	**14,950**	**15,079**	**15,101**	**15,135**	**15,316**	**15,418**	**15,491**	**16,133**	**15,863**	**16,318**	**16,541**	**16,541**	**16,541**	**16,726**	**16,914**
PEAK DEMAND															
Retail	9,060	9,222	9,379	9,558	9,722	9,879	10,038	10,193	10,336	10,485	10,630	10,777	10,916	11,077	11,238
Wholesale	4,156	4,205	4,252	4,296	4,344	4,376	4,429	4,495	4,552	4,601	4,661	4,711	4,767	4,831	4,886
Firm (Duke Area)	150	150	150	150	150	150	150	150	150	150	150	150			
Mitigation Sale	325	325													
OBLIGATION BEFORE DSM	13,691	13,902	13,781	14,004	14,216	14,404	14,618	14,838	15,038	15,235	15,442	15,638	15,684	15,907	16,124
DSM & EE	828	881	933	985	1,031	1,073	1,116	1,162	1,208	1,253	1,297	1,338	1,375	1,409	1,441
OBLIGATION AFTER DSM	12,862	13,021	12,848	13,019	13,185	13,332	13,501	13,676	13,830	13,982	14,145	14,300	14,309	14,498	14,684
RESERVES (2)	2,087	2,058	2,253	2,116	2,131	2,086	1,990	2,457	2,033	2,336	2,396	2,241	2,232	2,228	2,230
Capacity Margin (3)	14%	14%	15%	14%	14%	14%	13%	15%	13%	14%	14%	14%	13%	13%	13%
Reserve Margin (4)	16%	16%	18%	16%	16%	16%	15%	18%	15%	17%	17%	16%	16%	15%	15%
ANNUAL SYSTEM ENERGY (GWh)	**66,066**	**66,821**	**66,575**	**67,520**	**68,333**	**69,024**	**69,867**	**70,569**	**71,234**	**71,980**	**72,729**	**73,558**	**74,172**	**75,090**	**76,025**

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 / System Firm Load after DSM * 100.

Progress Energy Carolinas

Table 2   2012 Annual IRP (Winter)

	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
GENERATION CHANGES															
Sited Additions	1,049	717													
Undesignated Additions (1)					147	56	476	210	875	225	875	225			210
Planned Project Uprates	78	9		28											
Retirements	(1,039)	(602)													
INSTALLED GENERATION															
Nuclear	3,668	3,677	3,677	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705
Fossil	4,170	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568
Combined Cycle	2,321	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038
Combustion Turbine	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608
Hydro	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227
Undesignated (1)					147	203	679	889	1,764	1,989	2,864	3,089	3,089	3,089	3,299
TOTAL INSTALLED	**13,994**	**14,118**	**14,118**	**14,146**	**14,293**	**14,349**	**14,825**	**15,035**	**15,910**	**16,135**	**17,010**	**17,235**	**17,235**	**17,235**	**17,445**
PURCHASES & OTHER RESOURCES															
SEPA	95	95	109	109	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
NUG QF - Renewable	236	236	234	268	268	220	221	221	221	205	207	207	207	207	210
Butler Warner	260	260	260	260	260										
Anson CT Tolling Purchase	365	365	365	365	365	365	365	365	365	365	365	365	365	365	365
Hamlet CT Tolling Purchase		168	168	168	168	168	168								
Broad River CT	880	880	880	880	880	880	880	880	880	381					
Southern CC Purchase - LT	145	145	145	145	145	145	145								
TOTAL SUPPLY RESOURCES	**16,000**	**16,292**	**16,305**	**16,366**	**16,513**	**16,261**	**16,738**	**16,635**	**17,510**	**17,220**	**17,716**	**17,941**	**17,941**	**17,941**	**18,154**
OBLIGATION BEFORE DSM	12,658	12,859	13,052	13,263	13,464	13,642	13,844	14,053	14,241	14,428	14,624	14,809	14,845	15,056	15,262
DSM & EE	751	781	809	837	862	884	909	935	962	988	1,014	1,039	1,062	1,083	1,103
OBLIGATION AFTER DSM	11,907	12,078	12,242	12,426	12,602	12,758	12,935	13,118	13,279	13,440	13,609	13,770	13,783	13,973	14,159
RESERVES (2)	4,092	4,214	4,062	3,940	3,911	3,503	3,803	3,518	4,231	3,780	4,106	4,170	4,158	3,968	3,995
Capacity Margin (3)	26%	26%	25%	24%	24%	22%	23%	21%	24%	22%	23%	23%	23%	22%	22%
Reserve Margin (4)	34%	35%	33%	32%	31%	27%	29%	27%	32%	28%	30%	30%	30%	28%	28%

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.

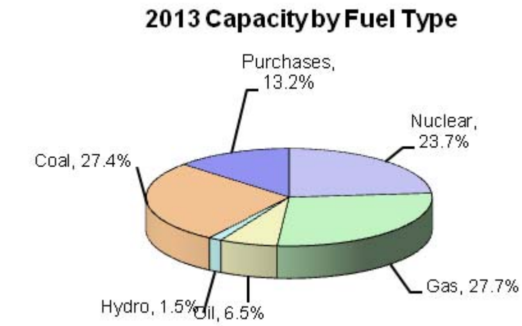
(3) Capacity Margin = Reserves / Total Supply Resources * 100.

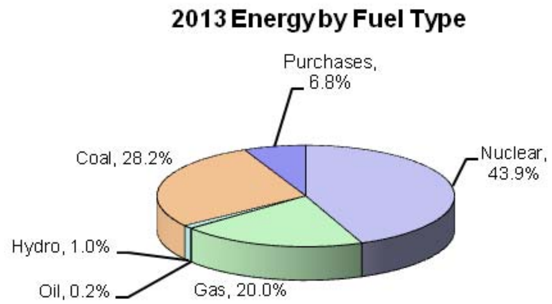
(4) Reserve Margin = Reserves / System Firm Load after DSM * 100.

Capacity and Energy

Figure 3 below shows PEC's capacity (MW) and energy (MWh) by fuel type projected for 2013. Nuclear and coal generation currently make-up approximately 51% of total capacity resources, yet account for about 72% of total energy requirements. Gas and oil generation accounts for about 34% of total supply capacity, yet about 20% of total energy (gas- 20%, oil- almost zero); the balance is from hydro and purchased power.

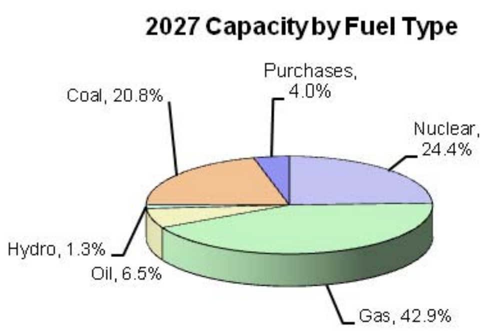
Figure 3

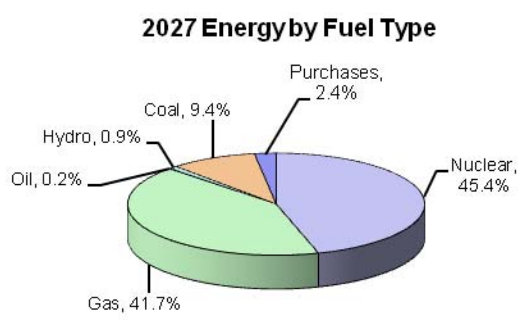




The Company's resource plan includes additions fueled by natural gas and oil, as well as possible new baseload generation. The Company's capacity and energy by fuel type projected for 2027 are shown in Figure 4. Gas and oil resources are projected to be 49% of total supply capacity, while serving about 42% (gas- 42%, oil- almost zero) of the total energy requirements. In 2027, nuclear and coal are projected to be approximately 45% of total capacity resources and serve about 55% of total system energy requirements. By 2027, the percentage share of system capacity is approximately the same between gas/oil resources versus nuclear/coal resources; however, nuclear and coal resources will continue to satisfy more than half of the system energy requirements.

Figure 4





Load Duration Curves

Figures 5 through 8 below are load duration curves for 2013 and 2027. The load duration curves detail the need relative to hours of the year, which is shown as a percentage. Figures 5 and 6 show curves with and without DSM for 2013 and 2027 respectively. It does not show existing EE as it is embedded in the forecast at this point. For clarity Figures 7 and 8 show the reduction of peak load due to DSM which reduces the need for additional peaking generation for the highest 15% of the annual hours. By comparing the 2013 and 2027 curves it is also possible to see the growth that is expected.

Figure 5

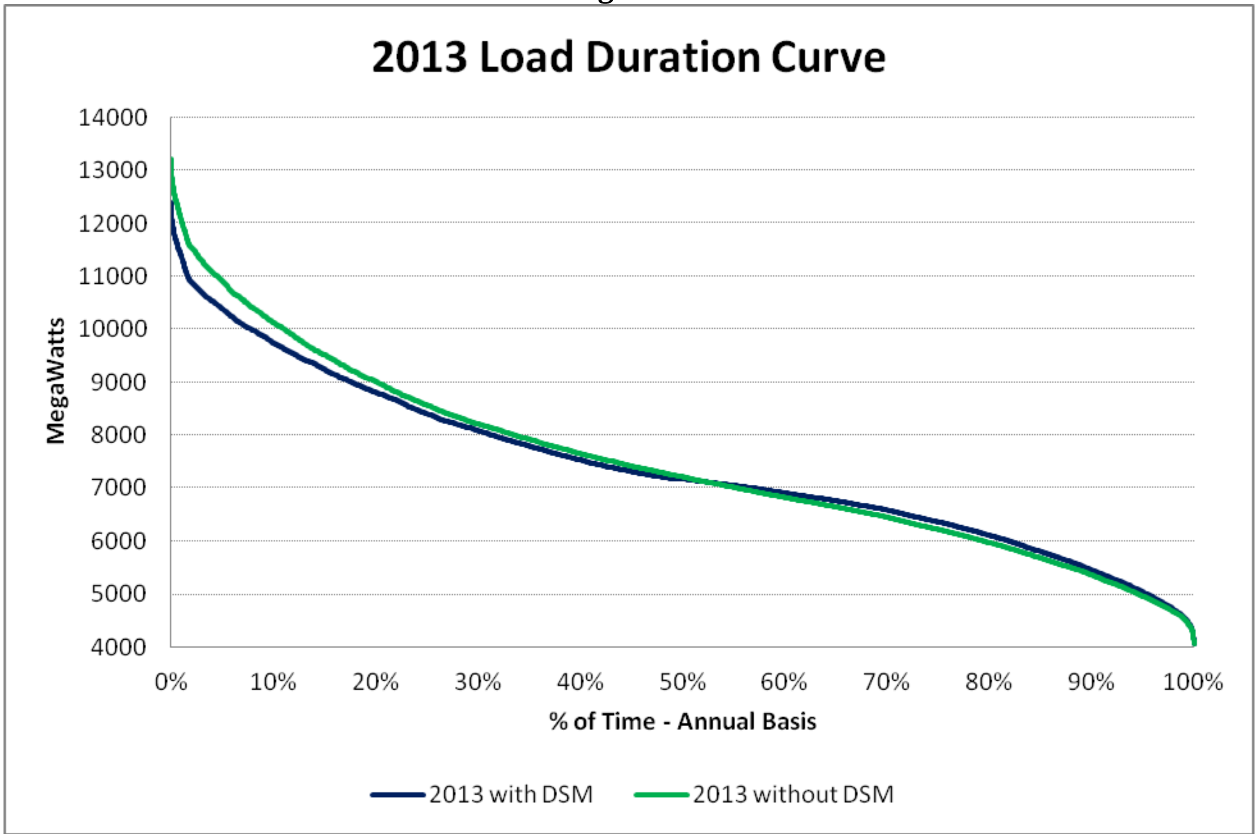


Figure 6

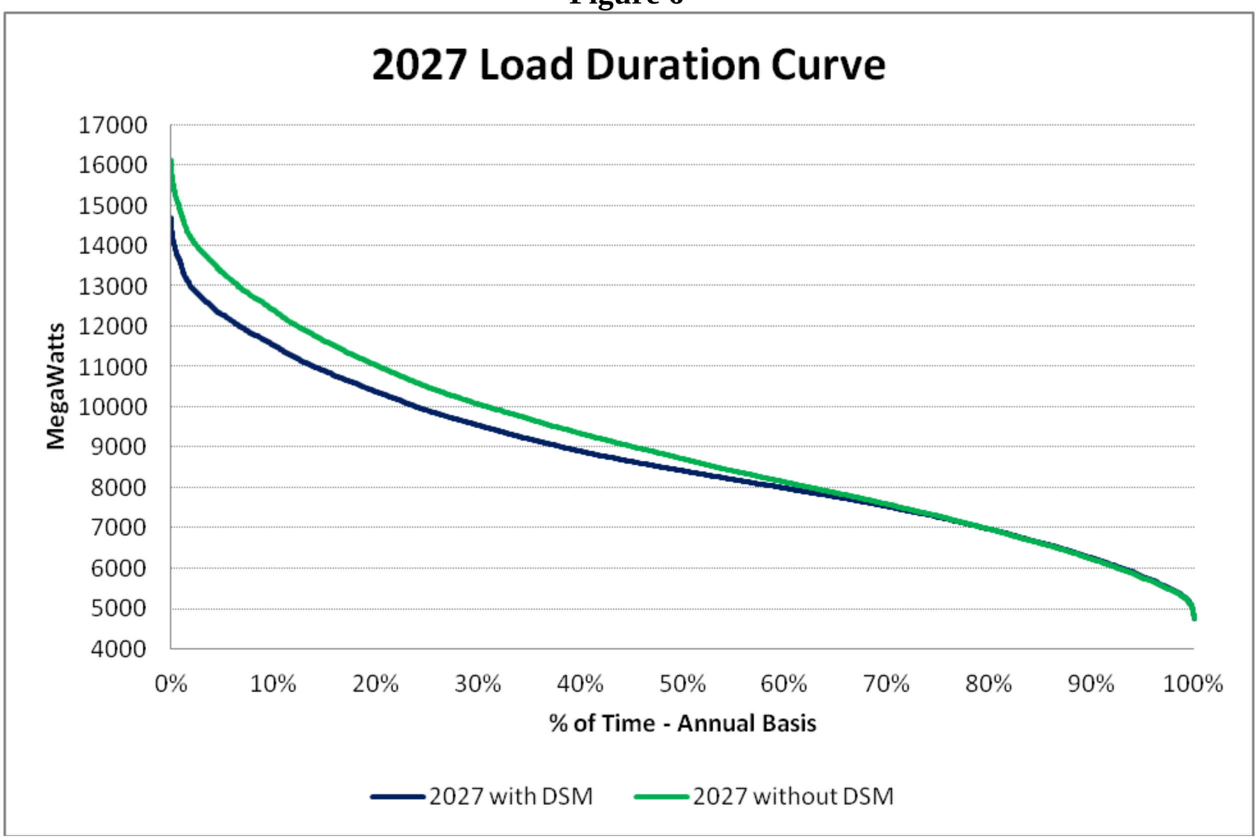


Figure 7

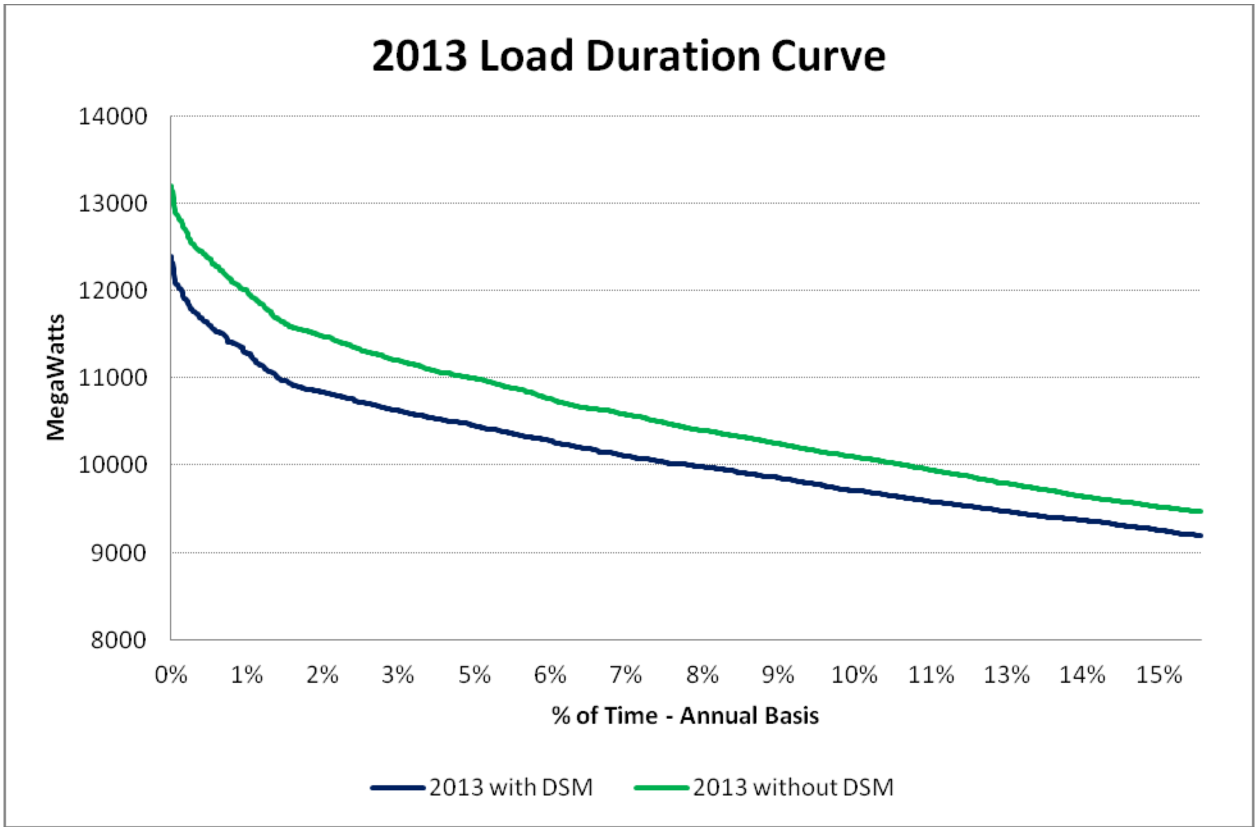
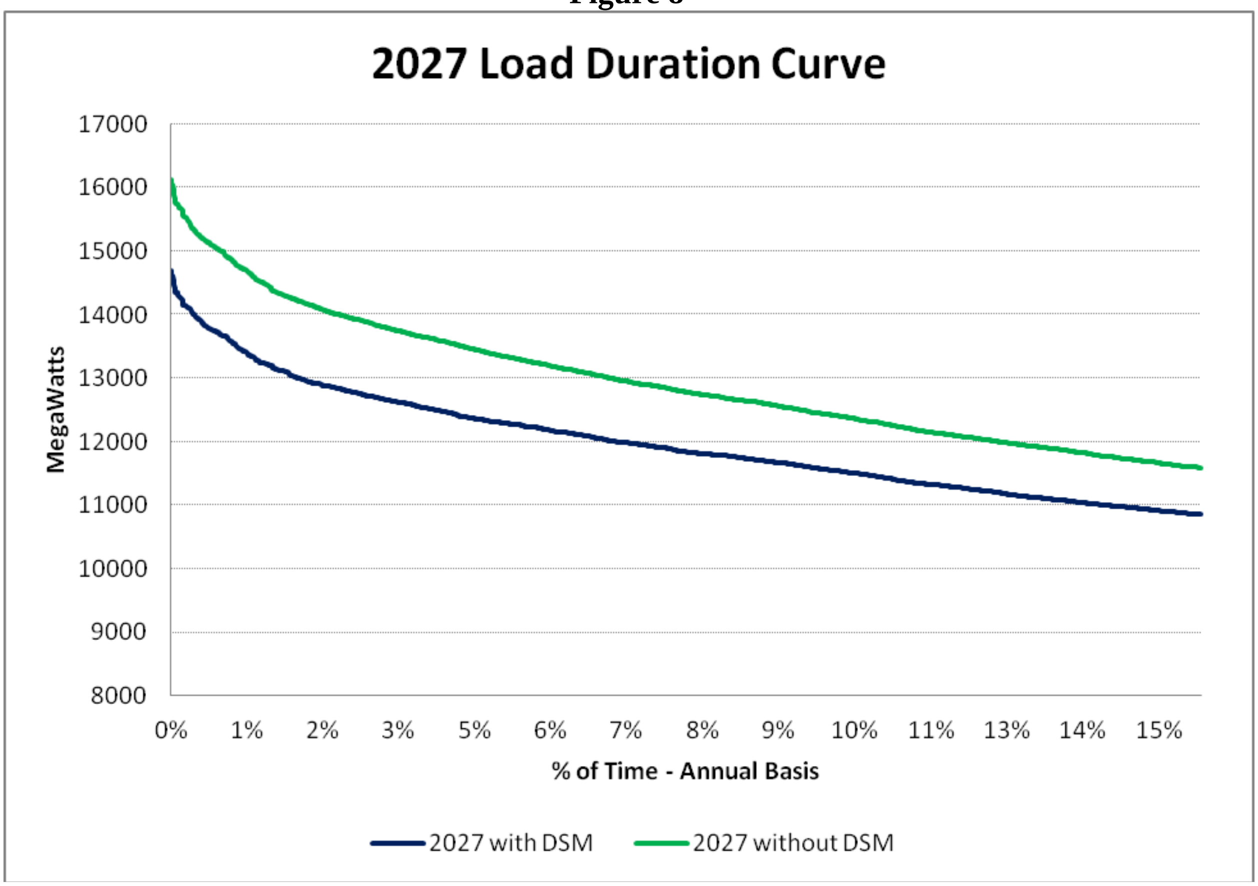


Figure 8



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. PEC's balanced approach is also essential in order to mitigate rate impacts resulting from volatility in individual fuel and CO_2 prices. 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.

PEC's balanced plan is shown to be 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 Carolinas

Integrated Resource Plan

Appendix A
Evaluation of Resource Options

November 2012

Resource Planning Analytics and Evaluations for Plan Development

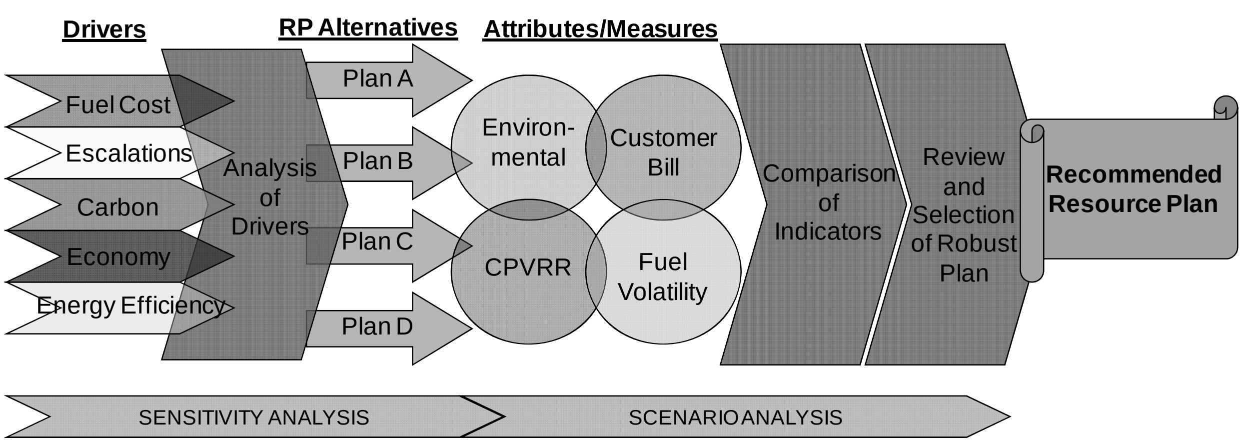
The objective of the resource planning process is to create a robust plan. A robust plan is one that provides the greatest potential benefits given the uncertainties, constraints, and volatility of key drivers that are currently affecting the plan or have a significant probability of influencing the plan in the future. In order to complete this objective, the resource planning process is comprised of a two-phase process that takes into consideration numerous factors, both current and future, related to issues such as customer costs, fuel costs, environmental requirements, demand side management (DSM), energy efficiency (EE), load and energy changes, and changes in 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 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 significantly change the resource plan. This 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 of the world (scenarios) that bound the potential outcomes of the key drivers such as load, energy, cost escalations, 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, how each of the plans fare in each scenario and in aggregate for all scenarios can be determined. The ranking of each plan in each scenario is performed using key attributes in the categories of customer cost and environmental performance. In short, the scenario analysis develops bounding potential future 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

Significant uncertainty remains as to what the future will hold 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 was to identify the key factors that impact the total cost of a resource plan. In the past couple of years, some of the issues that were "emerging" have either become realities or have been pushed to the background. Carbon legislation has been pushed further into the background and is not expected to be enacted any time soon. The "shale gale" of natural gas has recently pushed gas prices down to levels not seen in two decades; although, prices have begun rising from the low levels seen during the spring of 2012 and are projected to increase significantly (in terms of year-over-year percentage; albeit, from extremely low values) over the next few years. While there have been changes in these issues, their final outcomes are far from being settled, and they still remain significant uncertainties. They are still important factors in developing the resource plan because they are significant drivers in the overall cost of a generation technology, and their long-term outcome is still uncertain.

It is important to identify which of these uncertainties and issues can significantly alter the direction that would be required by a resource plan. Each key driver is independently stressed in order to determine which of the drivers result in significantly different resource plans. It is important to understand some drivers have less impact on the resource plan and can be adapted to more easily; whereas, others have a more significant impact on the resource plan and may require new directions to be taken. 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. On the other hand, environmental changes such as CO_2 legislation can alter resource plans and their components significantly, and can require a greater change, which translates to greater risk.

The key drivers used in the sensitivity analysis are shown in Figure A-2, below. The resource options available to be picked in the optimization analysis are shown in Figure A-3.

Figure A-2. Sensitivities Analyzed

Driver	Sensitivity
Gas Prices	Low
	High
Construction Escalation	[redacted]
	[redacted]
Load & Energy	Low Growth
	High Growth
Energy Efficiency	High
CO_2 Prices	Low
	High

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

Figure A-3. Resource Options from Alternative Plans

Unit Type	Winter	Summer
CT 190	210	185
CC 2x1 G	875	787
CC 3x1 G	1323	1180
Nuclear (5%)	56	55
Nuclear (20%)	225	221

In addition to the resource options in Figure A-3, renewable resources and energy efficiency and demand-side management programs exist in all cases. The capacity and energy contributions of renewables and the demand and energy reduction from energy efficiency programs are shown in the Supporting Information section at the end of this appendix.

Figure A-4 shows the alternative plans that resulted from the sensitivity analysis. Each of these plans is the result of an optimization completed with the Strategist model taking into consideration operational criteria, construction schedules, generation and transmission capital costs, fuel costs, emissions costs, and more.

Figure A-4. Alternative Plans for Scenario Analysis

	Plan A	Plan B	Plan C	Plan D	
2012					2012
2013	Wayne CC	Wayne CC	Wayne CC	Wayne CC	2013
2014	Sutton CC	Sutton CC	Sutton CC	Sutton CC	2014
2015					2015
2016	3 West CTs	3 West CTs	3 West CTs	3 West CTs	2016
2017	ALWR 5%		ALWR 5%	ALWR 5%	2017
2018	2 CT 190	2 CT 190	2 CT 190	CC 3x1 G	2018
2019	ALWR 5% CT 190	2 CT 190	ALWR 5% CT 190	ALWR 5%	2019
2020	CC 2x1 G	2 CT 190	2 CT 190		2020
2021	ALWR 20%	CC 2x1 G	ALWR 20% 3 CT 190	ALWR 20% CC 2x1 G	2021
2022	CC 2x1 G	CC 2x1 G	2 CT 190		2022
2023	ALWR 20%		ALWR 20%	ALWR 20%	2023
2024			CT 190		2024
2025				CC 2x1 G	2025
2026	CT 190	CC 2x1 G	CT 190		2026
2027	CT 190		CT 190		2027
2028	CT 190		CC 2x1 G		2028
2029	CC 2x1 G			CT 190	2029
2030	CC 2x1 G	CC 3x1 G	CC 2x1 G	CC 3x1 G	2030
2031			CT 190		2031

Plan A

Plan A contains a mix of combustion turbine, combined cycle, and nuclear generation. These resources are cost-effective in cases when the driving assumptions in Figure A-2 are at the mid level and also when construction escalation rates are low. The nuclear generation is assumed to be "regional" plants with PEC owning a 5% share of two units in 2017 and 2019 and a 20% share of a second pair of units in 2021 and 2023. It should be noted that no regional nuclear agreements have been reached and as such, the plan simply represents a placeholder for possible future partnerships.

Plan B

Plan B consists of a mix of combustion turbine and combined cycle resources. This type of capacity was indicated in the low gas, low CO_2 price, and high construction escalation rate cases.

Plan C

Plan C is similar to Plan A with the exception that a significant amount of CT capacity is added rather than a balance of CTs and combined cycle units. This plan was indicated in the high gas sensitivity analysis. With gas prices high, existing coal units provide more energy for system needs and thus, more CTs are added to meet capacity requirements.

Plan D

Plan D is similar to Plan A with the exception that a significant amount of CC capacity is added rather than a balance of CTs and combined cycle units. This plan was indicated in the high CO_2 price sensitivity analysis. With high CO_2 prices, existing coal units are more expensive to operate than combined cycle units. Thus, more combined cycle units are selected to economically provide energy requirements and fewer CTs are selected (than Plan A).

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.

Aspirational Plan

An alternative resource plan was developed assuming a greater amount of energy efficiency (EE) than in the base forecast (see Supporting Information Section for a comparison of the high EE forecast to the base EE forecast). This alternative, or "Aspirational," Plan is similar to Plan A with the exception that less combined cycle capacity is needed due to the higher energy efficiency reducing the overall energy requirement. This plan contains regional nuclear and the same number of CTs as in Plan A (though the timing of some of the CTs is different). Since the high EE targets are viewed as extremely aggressive and required customer participation is uncertain, this plan was not passed through to the Scenario Analysis.

Scenario Analysis

Scenario Definition

The scenario analysis phase contemplates and develops future states that bound the potential outcomes of the key drivers such as construction cost escalations, gas prices, and carbon costs. The scenario analysis relies on PEC experts to determine which future states are probable and how 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-5 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. These scenarios range from a case where, in effect, costs are low (the Low Stress scenario) to a case where costs are very high (the Stringent Environmental scenario). The 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 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 positive attributes of the alternative plans relative to each other. A brief description of the attributes is given below.

Figure A-5. Scenarios Used to Stress Alternative Plans

Scenario	Definition	Gas Prices	Construction Escalation	CO2
Low Stress	- Carbon legislation enacted at low price levels - Gas prices at low case - Construction escalation rates are at the low end of the range	Low	Low	Low
Stringent Environmental	- Legislation drives a dramatic carbon tax (or cap) that results in high gas prices - Demand for natural gas increases, which drives up prices	High	Mid	High
Current Trends	- Current world scenario including CO2 tax mid case	Mid	Mid	Mid
Economic Revival	- Economy picks up, resulting in higher construction escalation rate and higher demand for natural gas, which increases gas prices - CO2 legislation enacted at mid prices	High	High	Mid

Evaluation Attributes

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 price growth attribute is measured by the compound average growth rate of annual prices based on the annual revenue requirements. The system fuel price volatility is the standard deviation in system average fuel prices based on a normal distribution of prices around the base, low, and high gas price forecasts.

Environmental Category

The key attributes in the Environmental category are SO_2, NO_x, mercury (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 are shown in Figure A-6 below.

Figure A-6. Attributes Used to Rank Alternative Plans

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

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 Scenario Analysis, in which the plans in Figure A-4 are subjected to the four scenarios described in Figure A-5 and are ranked according to the weightings of the key attributes shown in Figure A-6, can be seen in Figure A-7.

The top section of Figure A-7 shows the overall highest ranking plan for each scenario. This section of the figure shows Plan D to be the overall highest ranking plan in the Current Trends and Stringent Environmental scenarios. Plan B is the highest ranking plan under Low Stress conditions, and Plan C is the highest ranking plan in the Economic Revival scenario.

The bottom section provides the relative rank of each plan from 1 to 4, with 1 being the highest ranking plan in each scenario and 4 being the lowest ranking plan in each scenario, and provides additional insight to the results. This section shows that Plan D performed relatively weak in the Low Stress and Economic Revival scenarios, ranking as the third out of four plans. It also shows than Plans B and C both perform poorly under three out of four scenarios. On the other hand, Plan A performs well, ranking number two, under all scenarios.

Figure A-7. Scenario Analysis Results

Overall Highest Ranking Plan

Scenario			
Low Stress	**Stringent Environmental**	**Current Trends**	**Economic Revival**
Plan B	Plan D	Plan D	Plan C

Rank of Each Plan

	Scenario			
	Low Stress	**Stringent Environmental**	**Current Trends**	**Economic Revival**
Plan A	2	2	2	2
Plan B	1	4	3	4
Plan C	4	3	4	1
Plan D	3	1	1	3

Plan A, a mixture of CTs, CCs, energy efficiency, renewables, and regional nuclear, is able to score well in all scenarios because of its balance of resources. An examination of results for all the attributes in all the scenarios shows Plan A ranked second in all of the environmental attributes in all of the scenarios, and ranked first or second in all of the customer cost attributes in three out of four scenarios (performing poorly in only the Low Stress scenario).

The supporting information section at the end of this appendix contains the results of each scenario, and many of the key inputs to these scenarios and sensitivities.

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 fuel, construction cost escalation, and environmental costs were taken into consideration when testing the plans to determine robustness.

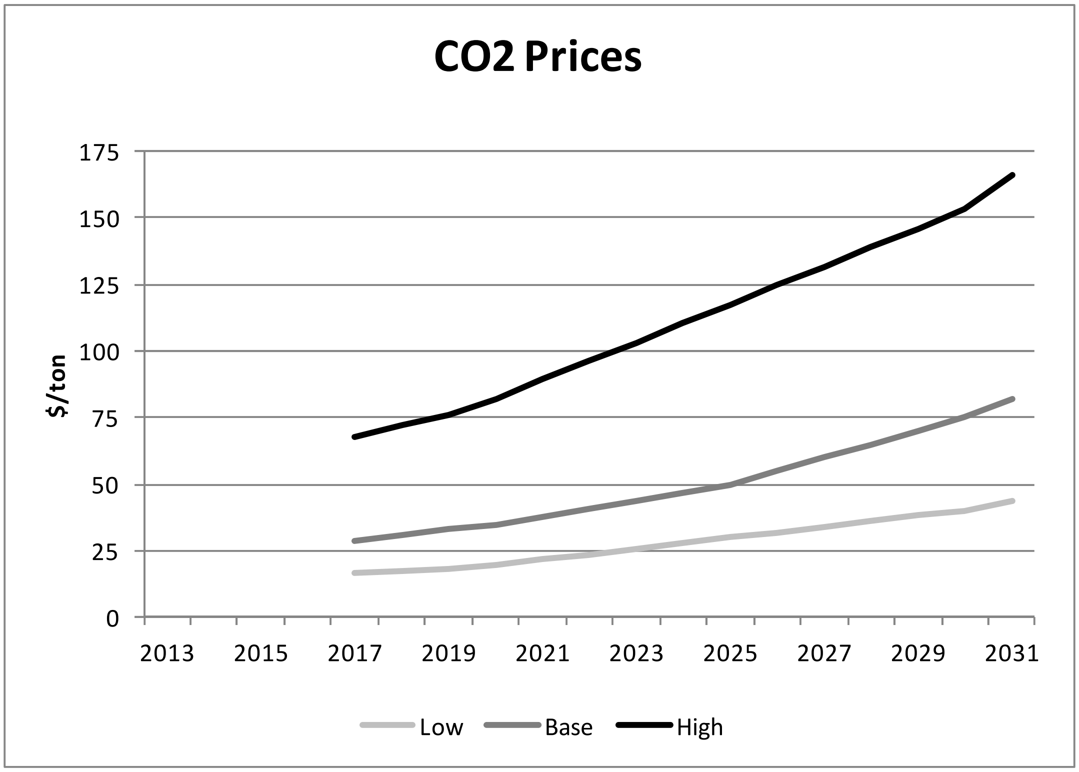
As seen from the results above, Plan A, which includes combustion turbines, combined cycle, nuclear, renewables, as well as DSM and EE, accomplishes the objective of a robust resource plan. Thus, it is the basis for the preferred resource plan shown in the IRP.

Supporting Information Section

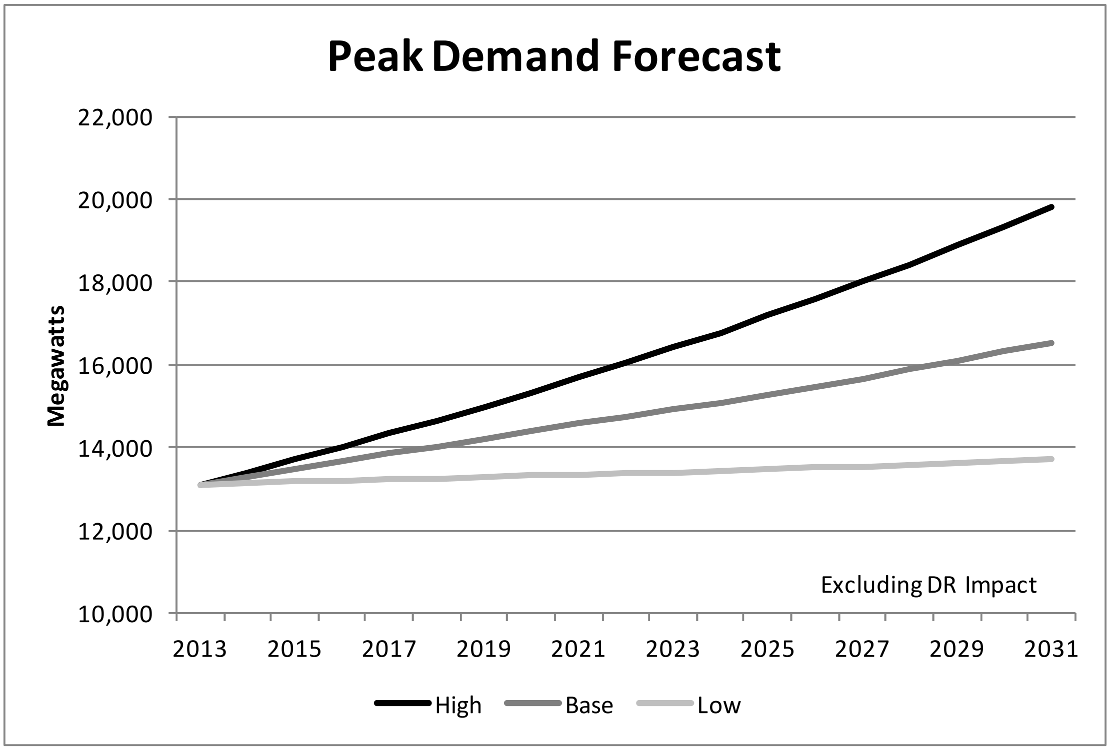
Gas Prices Utilized

This information is being filed confidentially.

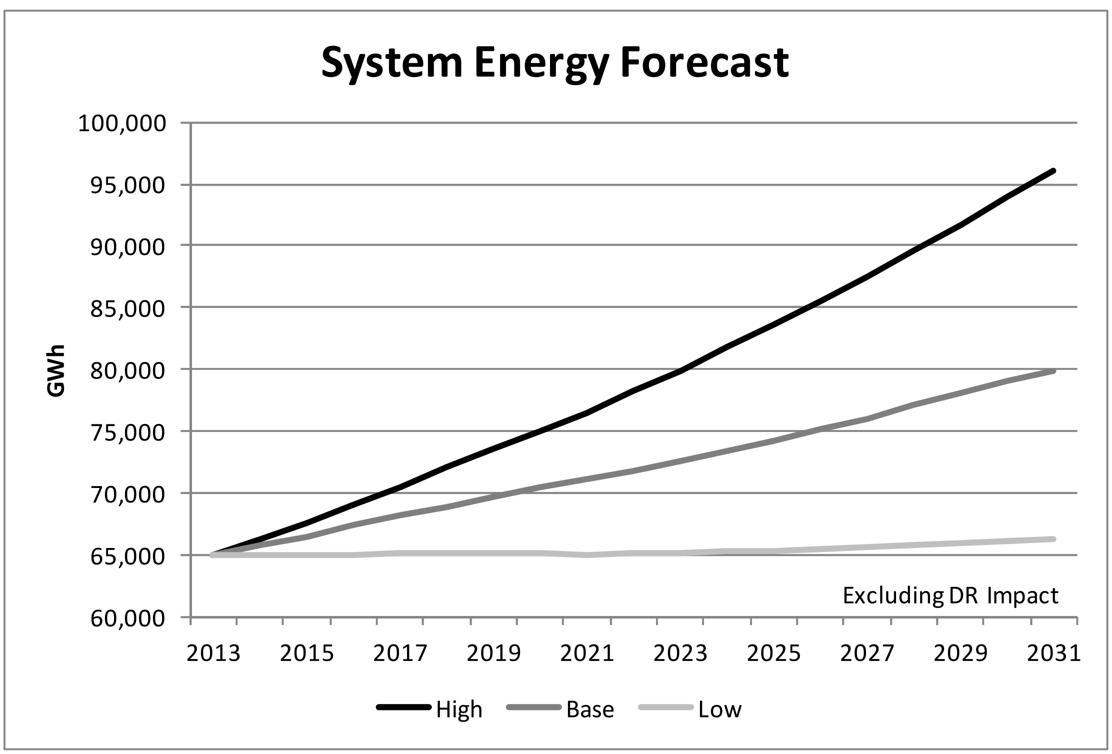
CO_2 Prices Utilized



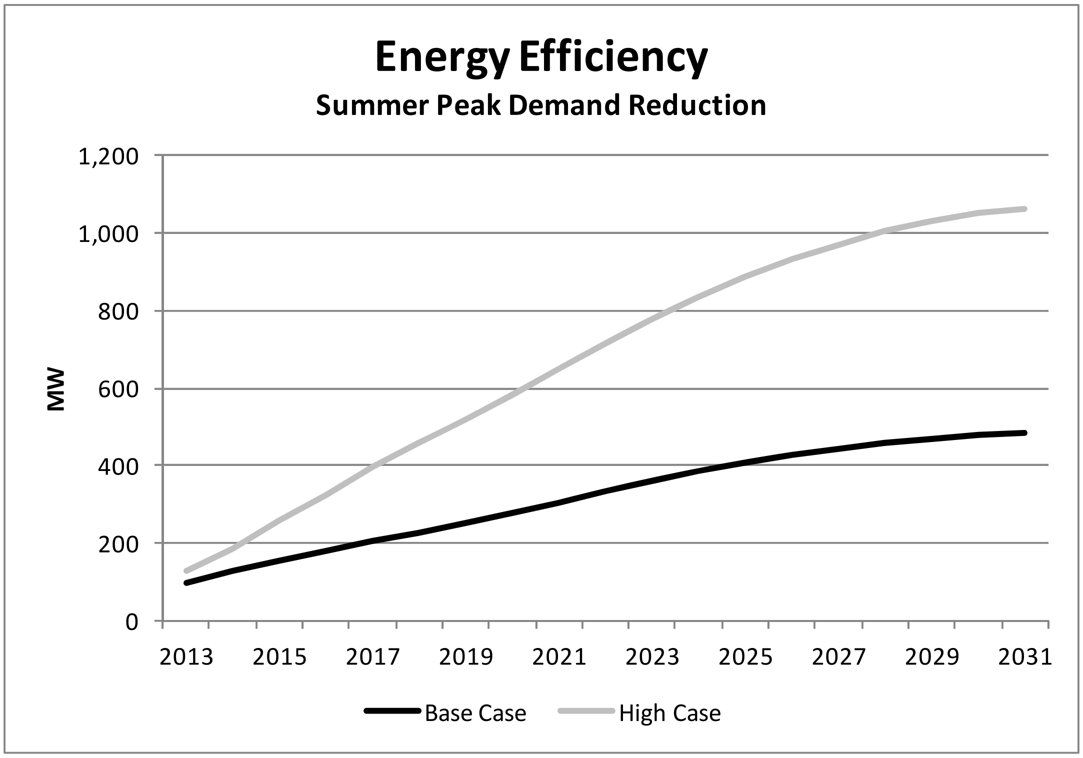
Peak Demand Forecasts Utilized

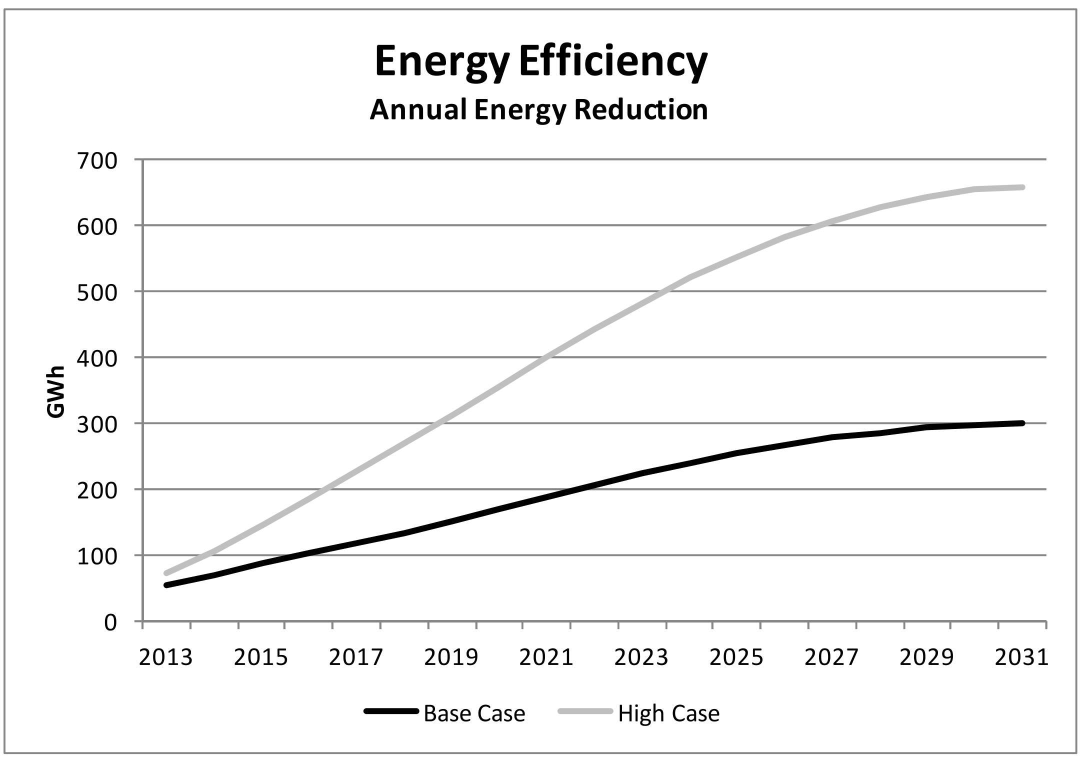


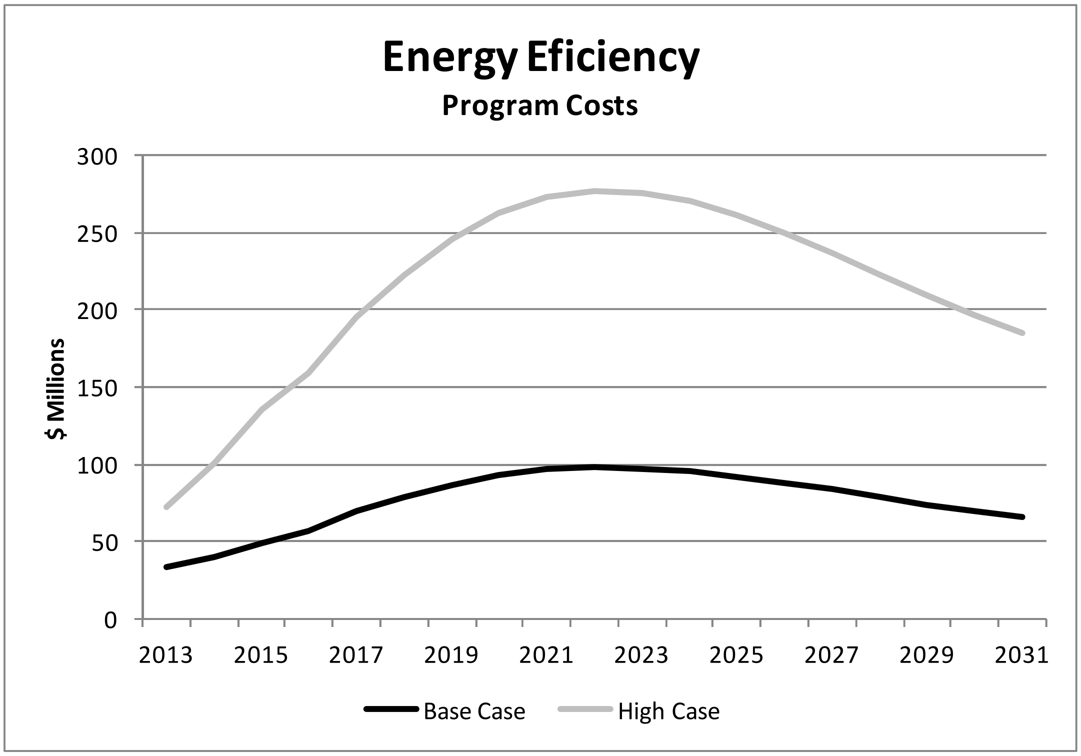
Energy Forecasts Utilized



Energy Efficiency Forecasts Utilized

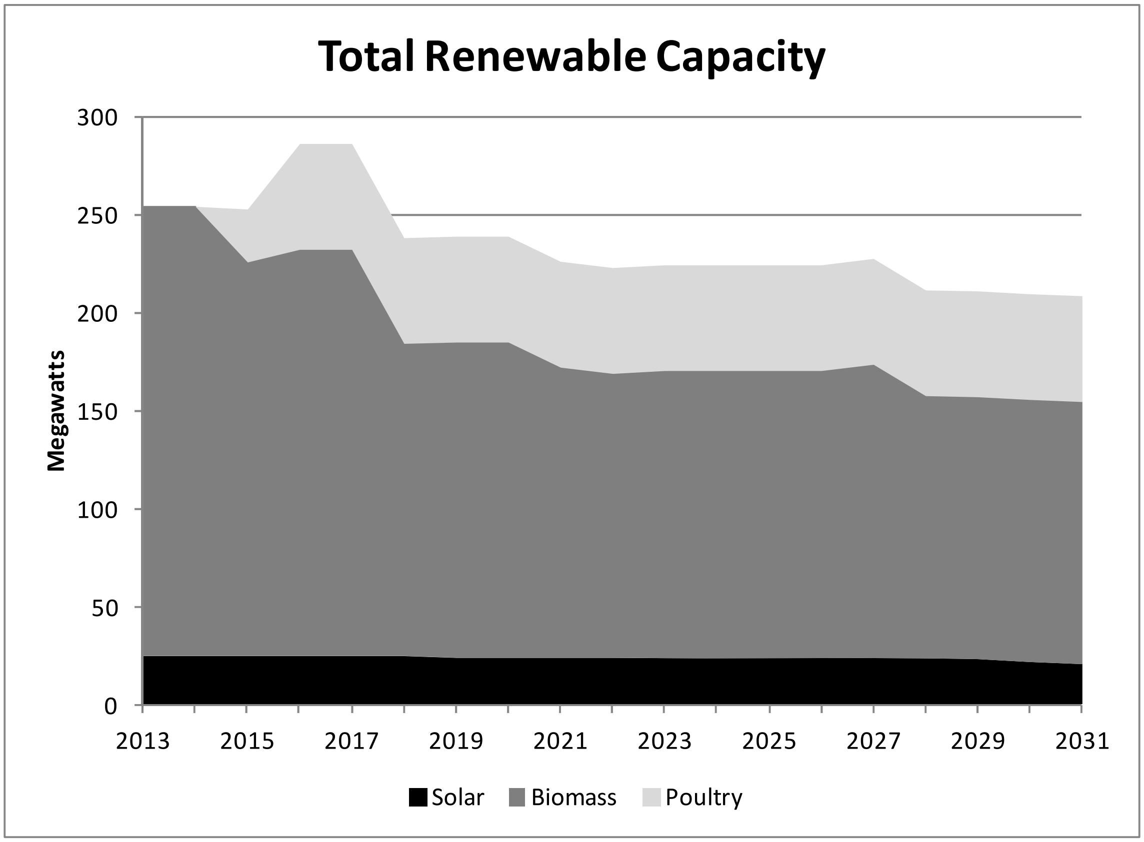


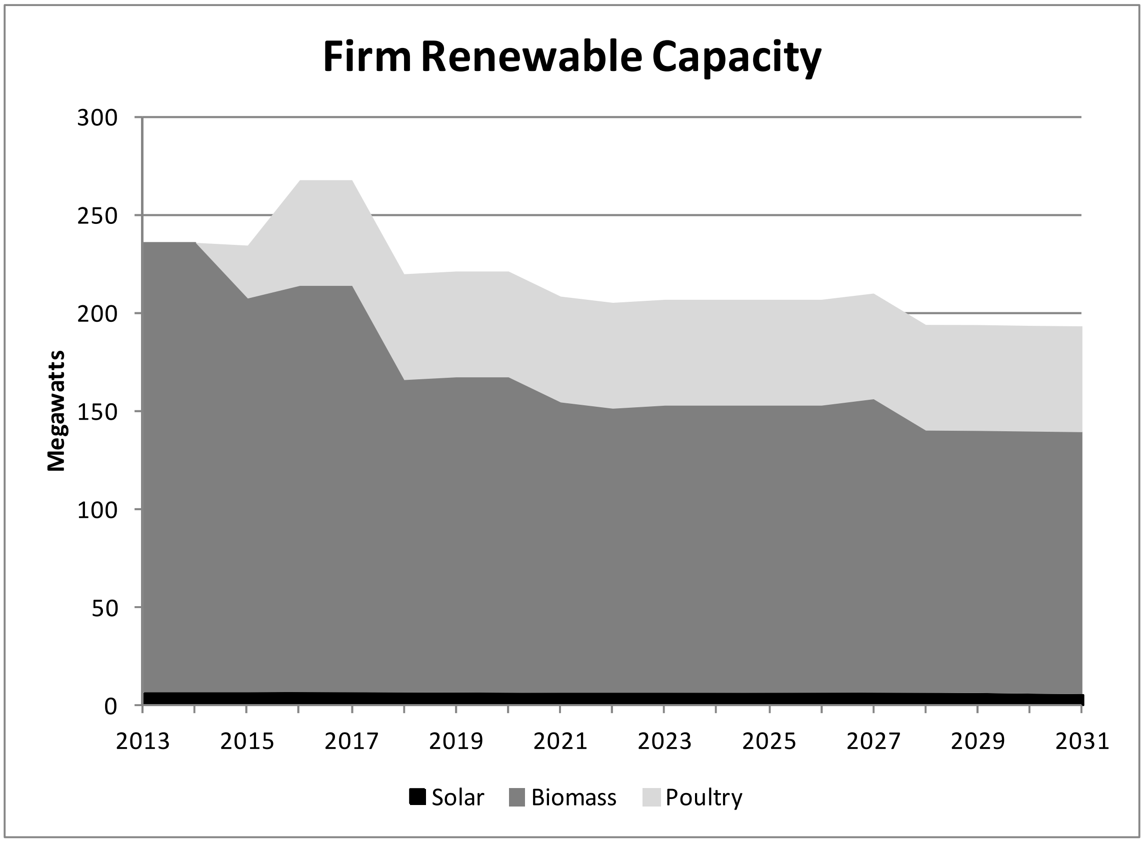


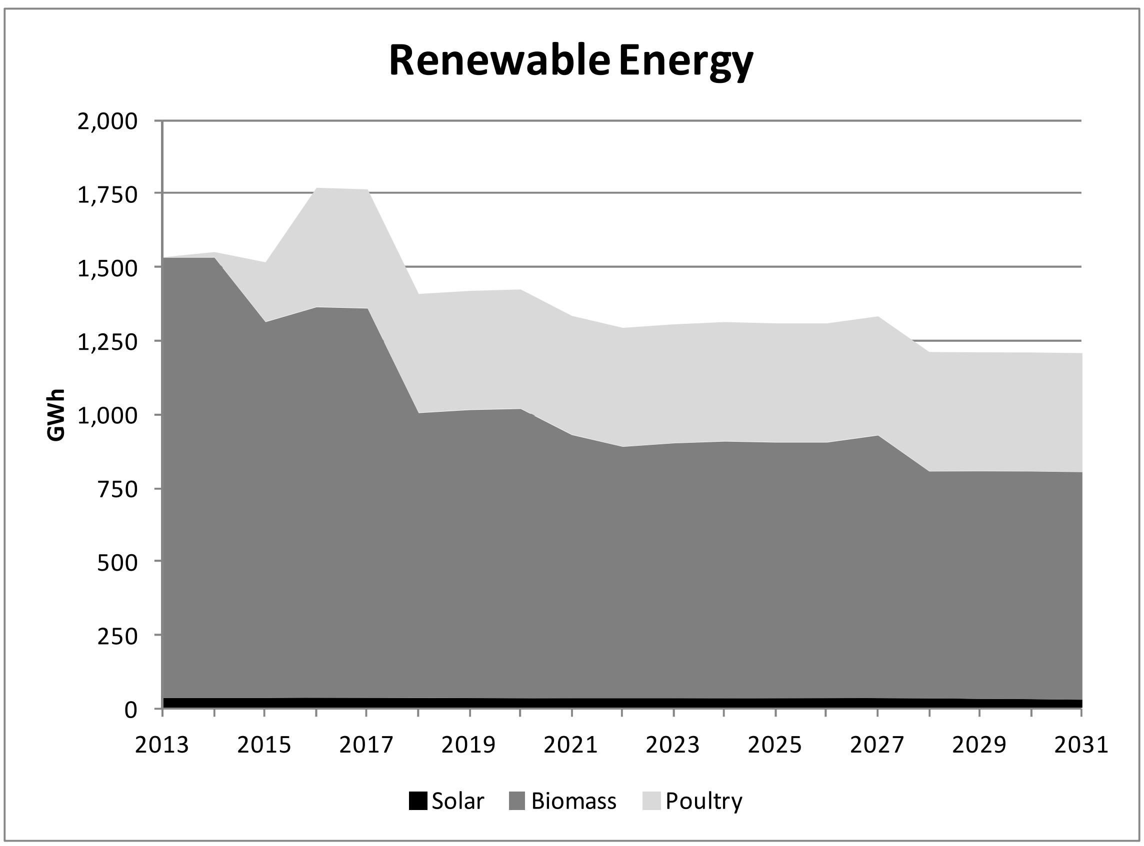


Energy Eficiency
Program Costs
$ Millions
300
250
200
150
100
50
0
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
Base Case
High Case

Renewables Capacity and Energy Utilized in Analyses




Firm Renewable Capacity
300
250
200
150
100
50
0
Megawatts
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
Solar
Biomass
Poultry


Renewable Energy
2,000
1,750
1,500
1,250
1,000
750
500
250
0
GWh
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
Solar
Biomass
Poultry

Scenario Analysis Results

Low Stress

	Objective	Plan A	Plan B	Plan C	Plan D
Customer Cost					
CPVRR ($ Millions)	min	51,216	48,715	51,439	52,086
CAGR of prices	min	1.92%	1.70%	1.94%	1.96%
System fuel price volatility	min	1.26	1.32	1.05	1.44
Environmental					
SO2 (tons)	min	129,897	134,526	165,926	116,220
NOx (tons)	min	79,255	84,445	98,259	69,824
Hg (lbs)	min	1,481	1,531	1,844	1,333
CO2 (1000s tons)	min	415,192	439,368	441,929	401,028

Score 0-10 Points Based on Value within Range (best=10, worst=0, interpolate between)

	Plan A	Plan B	Plan C	Plan D
Customer Cost	2.81	7.92	3.97	0.00
CPVRR	2.58	10.00	1.92	0.00
CAGR of prices	1.27	10.00	0.69	0.00
System fuel price volatility	4.65	3.08	10.00	0.00
Environmental	6.70	2.23	0.00	10.00
SO2	7.25	6.32	0.00	10.00
NOx	6.68	4.86	0.00	10.00
Hg	7.10	6.13	0.00	10.00
CO2	6.54	0.63	0.00	10.00
Weighted score	3.98	6.22	2.78	3.00
Rank	2	1	4	3

Stringent Environmental

	Objective	Plan A	Plan B	Plan C	Plan D
Customer Cost					
CPVRR ($ Millions)	min	135,722	140,033	136,370	136,148
CAGR of prices	min	5.97%	6.12%	6.06%	5.94%
System fuel price volatility	min	37.66	42.55	33.82	39.14
Environmental					
SO2 (tons)	min	541,944	571,782	674,116	463,799
NOx (tons)	min	125,747	133,271	152,277	110,803
Hg (lbs)	min	5,733	6,048	7,075	4,921
CO2 (1000s tons)	min	498,072	527,233	543,137	471,511

Score 0-10 Points Based on Value within Range (best=10, worst=0, interpolate between)

	Plan A	Plan B	Plan C	Plan D
Customer Cost	8.28	0.00	7.32	7.77
CPVRR	10.00	0.00	8.50	9.01
CAGR of prices	8.66	0.00	3.06	10.00
System fuel price volatility	5.60	0.00	10.00	3.90
Environmental	6.29	2.99	0.00	10.00
SO2	6.28	4.87	0.00	10.00
NOx	6.40	4.58	0.00	10.00
Hg	6.23	4.77	0.00	10.00
CO2	6.29	2.22	0.00	10.00
Weighted score	7.68	0.90	5.12	8.44
Rank	2	4	3	1

Current Trends

	Objective	Plan A	Plan B	Plan C	Plan D
Customer Cost					
CPVRR ($ Millions)	min	86,728	86,803	87,919	87,031
CAGR of prices	min	3.76%	3.74%	3.86%	3.74%
System fuel price volatility	min	8.67	9.84	9.59	8.39
Environmental					
SO2 (tons)	min	381,437	400,410	465,243	330,632
NOx (tons)	min	100,299	106,423	121,118	88,558
Hg (lbs)	min	4,160	4,370	5,022	3,620
CO2 (1000s tons)	min	461,544	488,528	497,143	440,310

Score 0-10 Points Based on Value within Range (best=10, worst=0, interpolate between)

	Plan A	Plan B	Plan C	Plan D
Customer Cost	8.96	6.66	0.52	8.98
CPVRR	10.00	9.37	0.00	7.45
CAGR of prices	8.46	9.70	0.00	10.00
System fuel price volatility	8.07	0.00	1.73	10.00
Environmental	6.25	2.47	0.00	10.00
SO2	6.23	4.82	0.00	10.00
NOx	6.39	4.51	0.00	10.00
Hg	6.15	4.65	0.00	10.00
CO2	6.26	1.52	0.00	10.00
Weighted score	8.15	5.40	0.36	9.29
Rank	2	3	4	1

Economic Revival

	Objective	Plan A	Plan B	Plan C	Plan D
Customer Cost					
CPVRR ($ Millions)	min	114,889	117,086	113,837	116,225
CAGR of prices	min	5.11%	5.20%	5.08%	5.14%
System fuel price volatility	min	27.40	31.88	26.14	28.24
Environmental					
SO2 (tons)	min	870,822	900,765	920,278	823,824
NOx (tons)	min	182,840	190,764	196,106	172,391
Hg (lbs)	min	9,065	9,363	9,563	8,593
CO2 (1000s tons)	min	595,483	624,193	615,456	579,190

Score 0-10 Points Based on Value within Range (best=10, worst=0, interpolate between)

	Plan A	Plan B	Plan C	Plan D
Customer Cost	7.13	0.00	10.00	4.53
CPVRR	6.76	0.00	10.00	2.65
CAGR of prices	6.93	0.00	10.00	5.21
System fuel price volatility	7.80	0.00	10.00	6.34
Environmental	6.03	0.62	1.36	10.00
SO2	5.13	2.02	0.00	10.00
NOx	5.59	2.25	0.00	10.00
Hg	5.13	2.06	0.00	10.00
CO2	6.38	0.00	1.94	10.00
Weighted score	6.80	0.19	7.41	6.17
Rank	2	4	1	3

Progress Energy Carolinas

Integrated Resource Plan

Appendix B
PEC Owned Generation

November 2012

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

Existing Generating Units and Ratings *(1, 3)*

All Generating Unit Ratings are as of December 31, 2011 unless otherwise noted.

Coal

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Asheville	1	196	191	Arden, NC	Coal	Base
Asheville	2	187	185	Arden, NC	Coal	Base
Cape Fear	5	148	144	Moncure, NC	Coal	Intermediate
Cape Fear	6	175	172	Moncure, NC	Coal	Intermediate
Lee	1	80	74	Goldsboro, NC	Coal	Peaking
Lee	2	80	68	Goldsboro, NC	Coal	Peaking
Lee	3	252	240	Goldsboro, NC	Coal	Intermediate
Mayo *(2)*	1	735	727	Roxboro, NC	Coal	Base
Robinson	1	179	177	Hartsville, SC	Coal	Base
Roxboro	1	374	364	Semora, NC	Coal	Base
Roxboro	2	667	659	Semora, NC	Coal	Base
Roxboro	3	698	696	Semora, NC	Coal	Base
Roxboro *(2)*	4	711	698	Semora, NC	Coal	Base
Sutton	1	98	97	Wilmington, NC	Coal	Intermediate
Sutton	2	107	104	Wilmington, NC	Coal	Intermediate
Sutton	3	397	374	Wilmington, NC	Coal	Intermediate
Total Coal		5,084	4,970			

Combustion Turbines

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Asheville	3	185	164	Arden, NC	Natural Gas/Oil	Peaking
Asheville	4	185	160	Arden, NC	Natural Gas/Oil	Peaking
Blewett	1	17	13	Lilesville, NC	Oil	Peaking
Blewett	2	17	13	Lilesville, NC	Oil	Peaking
Blewett	3	16	13	Lilesville, NC	Oil	Peaking
Blewett	4	17	13	Lilesville, NC	Oil	Peaking
Cape Fear	1A	14	11	Moncure, NC	Oil	Peaking
Cape Fear	1B	14	12	Moncure, NC	Oil	Peaking
Cape Fear	2A	14	12	Moncure, NC	Oil	Peaking
Cape Fear	2B	14	11	Moncure, NC	Oil	Peaking

Darlington	1	65	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	2	67	48	Hartsville, SC	Oil	Peaking
Darlington	3	67	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	4	66	52	Hartsville, SC	Oil	Peaking
Darlington	5	66	52	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	6	67	45	Hartsville, SC	Oil	Peaking
Darlington	7	67	51	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	8	66	49	Hartsville, SC	Oil	Peaking
Darlington	9	59	52	Hartsville, SC	Oil	Peaking
Darlington	10	67	51	Hartsville, SC	Oil	Peaking
Darlington	11	67	52	Hartsville, SC	Oil	Peaking
Darlington	12	133	118	Hartsville, SC	Natural Gas/Oil	Peaking
Darlington	13	133	116	Hartsville, SC	Natural Gas/Oil	Peaking
Lee	1	15	12	Goldsboro, NC	Oil	Peaking
Lee	2	27	21	Goldsboro, NC	Oil	Peaking
Lee	3	27	21	Goldsboro, NC	Oil	Peaking
Lee	4	27	21	Goldsboro, NC	Oil	Peaking
Morehead	1	15	12	Morehead City, NC	Oil	Peaking
Smith (4)	1	178	162	Hamlet, NC	Natural Gas/Oil	Peaking
Smith (4)	2	183	167	Hamlet, NC	Natural Gas/Oil	Peaking
Smith (4)	3	185	169	Hamlet, NC	Natural Gas/Oil	Peaking
Smith (4)	4	186	163	Hamlet, NC	Natural Gas/Oil	Peaking
Smith (4)	6	187	159	Hamlet, NC	Natural Gas/Oil	Peaking
Robinson	1	15	11	Hartsville, SC	Natural Gas/Oil	Peaking
Sutton	1	14	11	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2A	31	24	Wilmington, NC	Oil/Natural Gas	Peaking
Sutton	2B	31	26	Wilmington, NC	Oil/Natural Gas	Peaking
Wayne	1/10	192	177	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	2/11	192	174	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	3/12	193	173	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	4/13	191	170	Goldsboro, NC	Oil/Natural Gas	Peaking
Wayne	5/14	197	169	Goldsboro, NC	Oil/Natural Gas	Peaking
Weatherspoon	1	41	33	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	2	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	3	41	34	Lumberton, NC	Natural Gas/Oil	Peaking
Weatherspoon	4	41	32	Lumberton, NC	Natural Gas/Oil	Peaking
Total CT		3,733	3,185			

Combined Cycle

	Unit	Winter (MW)	Summer (MW)	Location	Fuel Type	Resource Type
Smith (4)	CT7	180	151	Hamlet, NC	Natural Gas/Oil	Base
Smith (4)	CT8	180	151	Hamlet, NC	Natural Gas/Oil	Base
Smith (4)	ST4	172	168	Hamlet, NC	Natural Gas/Oil	Base
Smith (4)	CT9	228	182	Hamlet, NC	Natural Gas/Oil	Base
Smith (4)	CT10	228	182	Hamlet, NC	Natural Gas/Oil	Base
Smith (4)	ST5	252	250	Hamlet, NC	Natural Gas/Oil	Base
Total CC		1240	1084			

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	5	4	Lilesville, NC	Water	Intermediate
Blewett	5	5	4	Lilesville, NC	Water	Intermediate
Blewett	6	5	4	Lilesville, NC	Water	Intermediate
Marshall	1	2	2	Marshall, NC	Water	Intermediate
Marshall	2	2	2	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	24	27	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		227	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	932	Southport, NC	Uranium	Base
Harris *(2)*	1	936	900	New Hill, NC	Uranium	Base
Robinson	2	758	724	Hartsville, SC	Uranium	Base
Total Nuclear		3,622	3,494			
TOTAL PEC SYSTEM		**13,906**	**12,958**			

Footnotes:

(1) Ratings reflect compliance with NERC reliability standards and are gross of co-ownership interest as of 12/31/11.
(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) Resource type based on NERC capacity factor classifications which may alternate over the forecast period.
(4) Richmond County Plant renamed to Sherwood H. Smith Jr. Energy Complex.

Planned Designated Generation (1)

Plant Name	Location	Summer Capacity (MW)	Plant Type	Fuel Type	Expected In-Service Date
Wayne County	Goldsboro, NC	920	CC	Natural Gas/Oil	01/2013
Sutton	Wilmington, NC	625	CC	Natural Gas/Oil	12/2013

Notes:

(1) In 2006, PEC announced that it selected a site at the Shearon Harris Nuclear Plant (Harris) to evaluate for possible future nuclear expansion. PEC selected the Westinghouse Electric AP1000 reactor design as the technology upon which to base its application submission. On February 19, 2008, PEC filed a COL application with the NRC for two additional reactors at Harris, which the NRC docketed on April 17, 2008. No petitions to intervene have been admitted in the Harris COL application. If we receive COL approval from the NRC in 2014 and applicable state agency approvals, and if the decisions to build are made, a new plant would not be online prior to 2026.

Units Planned to Be Retired

Unit & Plant Name	Location	Capacity (MW) Winter / Summer	Fuel Type	Expected Retirement Date
Lee 1	Goldsboro, NC	80 / 74	Coal	09/2012
Lee 2	Goldsboro, NC	80 / 68	Coal	09/2012
Lee 3	Goldsboro, NC	252 / 240	Coal	09/2012
Sutton 1	Wilmington, NC	98 / 97	Coal	12/2013
Sutton 2	Wilmington, NC	107 / 104	Coal	12/2013
Sutton 3	Wilmington, NC	397 / 374	Coal	12/2013
Cape Fear 5	Moncure, NC	148 / 144	Coal	10/2012
Cape Fear 6	Moncure, NC	175 / 172	Coal	10/2012
Robinson 1	Hartsville, SC	179 / 177	Coal	10/2012
Cape Fear 2B	Moncure, NC	14 / 11	Oil	10/2012
Lee 1	Goldsboro, NC	15 / 12	Oil	10/2012
Lee 2	Goldsboro, NC	27 / 21	Oil	10/2012
Lee 3	Goldsboro, NC	27 / 21	Oil	10/2012
Lee 4	Goldsboro, NC	27 / 21	Oil	10/2012
Morehead 1	Morehead City, NC	15 / 12	Oil	10/2012
Total		1,641 MW / 1,548 MW		

Planned Uprates

Unit	Date	Winter MW	Summer MW
Brunswick 2	2015	10	10
Robinson 2 (1)	2012	20	20
Robinson 2	2013	5	5
Richmond CT7	2012	12	9
Richmond CT8	2012	12	9
Richmond ST4	2012	8	5
Harris 1 (1)	2012	10	10
Harris 1 (1)	2012	16	16
Harris 1	2013	4	4
Harris 1	2015	18	14

Note: (1) Unit uprate implemented in 2012; capacity not reflected in Existing Generating Units and Ratings section.

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 (1)	Lilesville, NC	04/30/08	*Pending*	2058 (2)
Tillery #1-4 (1)	Mr. Gilead, NC	04/30/08	*Pending*	2058 (2)
Robinson #2	Hartsville, SC	07/31/10	04/19/2004	07/31/2030
Brunswick #2	Southport , NC	12/27/14	06/26/2006	12/27/2034
Brunswick #1	Southport, NC	09/08/16	06/26/2006	09/08/2036
Harris #1	New Hill, NC	10/24/26	12/12/2008	10/24/2046

Notes:

(1) The license renewal application for the Blewett and Tillery Plants was filed with the FERC on 04/26/06; the Company is awaiting issuance of the new license from FERC. Pending receipt of a new license, these plants are currently operating under a renewable one-year license extension which has been in effect since May 2008. Although Progress Energy has requested a 50-year license, FERC may not grant this term.

(2) Estimated - New license expiration date will be determined by FERC license issuance date and term of granted license.

Progress Energy Carolinas

Integrated Resource Plan

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

November 2012

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	Summer Capacity (MW)	Capacity Designation	Location	Term	Volume of Purchases (MWh) Jul 11-Jun 12
Broad River CTs # 1-3	Gas	478	Peaking	Gaffney, SC	5/31/2021	402,408
Broad River CTs # 4-5	Gas	329	Peaking	Gaffney, SC	2/28/2022	241,531
Public Works Commission of the City of Fayetteville	Gas	220	Peaking	Fayetteville, NC	9/30/17	N/A
North Carolina Electric Membership Corporation (NCEMC)	Gas	112	Peaking	Hamlet, NC	12/31/13	N/A
NCEMC	Gas	168	Peaking	Hamlet, NC	1/1/2014-4/30/19	N/A
NCEMC	Gas	336	Peaking	Lilesville, NC (Anson)	12/31/32	N/A
Southern Company	Gas	145	Intermediate	Rowan County, NC	12/31/2019	950,153
RockTenn	Fossil/waste wood	25	Base	Florence, SC	12/31/2012	103,184

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 calendar year 2011 was 139,153 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	54	1/1/2009	12/31/2013
Fayetteville Public Works Commission	Full Requirements Power Supply	Native Load Firm	458	7/1/2012	6/30/2032
French Broad EMC	Full Requirements Power Supply	Native Load Firm	107	1/1/2004	12/31/2012
Haywood EMC	Partial Requirements Power Supply	Native Load Firm	42	1/1/2009	12/31/2021
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	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 Ext.	Native Load Firm	275 (2013), 325 (2014-2020), 150 (2021)	1/1/2013	12/31/2021
	NCEMC Intermediate	Native Load Firm	100	4/1/2007	12/31/2012
	NCEMC PPA	Subordinate to Native Load Firm	150 (2013-2024)	1/1/2005	12/31/2024
	NCEMC PSCA	Native Load Firm	1,266	1/1/2013	12/31/2032
North Carolina Eastern Municipal Power Agency	Partial Requirements Power Supply	Native Load Firm	649	1/1/2010	12/31/2017
North Carolina Eastern Municipal Power Agency	Partial Requirements Power Supply	Native Load Firm	763	1/1/2018	12/31/2031
Piedmont EMC	Partial Requirements Power Supply	Native Load Firm	24	9/1/2006	12/31/2021
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 Extension	Native Load Firm	15	1/1/2010	12/31/2015
Town of Winterville, NC	Full Requirements Power Supply	Native Load Firm	13	3/1/2008	12/31/2017

Notes: Contracts, unless information indicates otherwise, are assumed to extend in the forecast.
* Service Obligation Resource

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

Status as of July 2012

Facility Name	Location	Primary Fuel Type	Capacity	Designation	Inclusion in PEC Resources
		NORTH CAROLINA GENERATORS			
Customer 1	Eastern NC	Natural Gas	46,000 kW	Baseload	(1)
Customer 2	Western NC	Process By-product & Coal	51,000 kW	Baseload	(1)
Customer 3	Eastern NC	Process By-product	60,000 kW	Baseload	(1)
Customer 4	Western NC	Hydro	2,500 kW	Baseload	(1)
Customer 5	Eastern NC	Diesel Fuel	2,250 kW	Baseload	(1)
Customer 6	Eastern NC	Process By-product	50,000 kW	Intermediate	(1)
Customer 7	Eastern NC	Solar PV	500 kW	Intermediate	(1)
Customer 8	Eastern NC	Solar PV	260 kW	Intermediate	(1)
Customer 9	Western NC	Solar PV	900 kW	Intermediate	(1)
Customer 10	Eastern NC	Solar PV	144 kW	Intermediate	(1)
Customer 11	Eastern NC	Solar PV	450 kW	Intermediate	(1)
Customer 12	Eastern NC	Process By -products	27,000 kW	Baseload	(1)
Customer 13	Eastern NC	Diesel Fuel	5,000 kW	Peaking	(2)
Customer 14	Eastern NC	Diesel Fuel	1,800 kW	Peaking	(2)
Customer 15	Eastern NC	Diesel Fuel	5,000 kW	Peaking	(2)
Customer 16	Eastern NC	Diesel Fuel	300 kW	Peaking	(2)
Customer 17	Eastern NC	Diesel Fuel	300 kW	Peaking	(2)
Customer 18	Eastern NC	Diesel Fuel	2,472 kW	Peaking	(2)
Customer 19	Eastern NC	Diesel Fuel	6,000 kW	Peaking	(2)
Customer 20	Eastern NC	Diesel Fuel	6,500 kW	Peaking	(2)
Customer 21	Eastern NC	Solar PV	0 kW	Intermediate	(3)
Customer 22	Western NC	Solar PV	2 kW	Intermediate	(3)
Customer 23	Eastern NC	Solar PV	3 kW	Intermediate	(3)
Customer 24	Eastern NC	Solar PV	3 kW	Intermediate	(3)
Customer 25	Eastern NC	Solar PV	5 kW	Intermediate	(3)
Customer 26	Eastern NC	Solar PV	5 kW	Intermediate	(3)
Customer 27	Eastern NC	Solar PV	7 kW	Intermediate	(3)
Customer 28	Eastern NC	Solar PV	10 kW	Intermediate	(3)
Customer 29	Eastern NC	Solar PV	21 kW	Intermediate	(3)
Customer 30	Eastern NC	Solar PV	48 kW	Intermediate	(3)
Customer 31	Eastern NC	Solar PV	62 kW	Intermediate	(3)
Customer 32	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 33	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 34	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 35	Eastern NC	Diesel Fuel	750 kW	Peaking	(2)
Customer 36	Eastern NC	Diesel Fuel	3,000 kW	Peaking	(2)
Customer 37	Western NC	Diesel Fuel	750 kW	Peaking	(2)

Customer 38	Western NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 39	Eastern NC	Diesel Fuel	600 kW	Peaking	(2)
Customer 40	Western NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 41	Eastern NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 42	Eastern NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 43	Eastern NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 44	Eastern NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 45	Eastern NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 46	Eastern NC	Diesel Fuel	600 kW	Peaking	(2)
Customer 47	Eastern NC	Diesel Fuel	600 kW	Peaking	(2)
Customer 48	Eastern NC	Diesel Fuel	2,700 kW	Peaking	(2)
Customer 49	Eastern NC	Diesel Fuel	600 kW	Peaking	(2)
Customer 50	Western NC	Diesel Fuel	500 kW	Peaking	(2)
Customer 51	Eastern NC	Diesel Fuel	250 kW	Peaking	(2)
Customer 52	Eastern NC	Diesel Fuel	4,000 kW	Peaking	(2)
Customer 53	Eastern NC	Diesel Fuel	600 kW	Peaking	(2)
Customer 54	Eastern NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 55	Eastern NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 56	Eastern NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 57	Eastern NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 58	Eastern NC	Diesel Fuel	350 kW	Peaking	(2)
Customer 59	Eastern NC	Solar PV	2 kW	Intermediate	(3)
Customer 60	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 61	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 62	Eastern NC	Solar PV	4 kW	Intermediate	(3)
Customer 63	Eastern NC	Solar PV	3 kW	Intermediate	(3)
Customer 64	Eastern NC	Solar PV	2 kW	Intermediate	(3)
Customer 65	Eastern NC	Solar PV	3 kW	Intermediate	(3)
Customer 66	Eastern NC	Solar PV	1 kW	Intermediate	(3)
Customer 67	Eastern NC	Solar PV	2 kW	Intermediate	(3)
Customer 68	Eastern NC	Solar PV	5 kW	Intermediate	(3)
Customer 69	Eastern NC	Solar PV	2 kW	Intermediate	(3)
Customer 70	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 71	Eastern NC	Solar PV	9 kW	Intermediate	(3)
Customer 72	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 73	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 74	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 75	Eastern NC	Solar PV	3 kW	Intermediate	(3)
Customer 76	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 77	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 78	Eastern NC	Solar PV	7 kW	Intermediate	(3)
Customer 79	Eastern NC	Solar PV	3 kW	Intermediate	(3)
Customer 80	Eastern NC	Solar PV	1 kW	Intermediate	(3)
Customer 81	Eastern NC	Solar PV	2 kW	Intermediate	(3)
Customer 82	Eastern NC	Solar PV	16 kW	Intermediate	(3)
Customer 83	Eastern NC	Solar PV	N/A	Intermediate	(3)

Customer 84	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 85	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 86	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 87	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 88	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 89	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 90	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 91	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 92	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 93	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 94	Eastern NC	Solar PV	2.9 kW	Intermediate	(3)
Customer 95	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 96	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 97	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 98	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 99	Eastern NC	Solar PV	4.1 kW	Intermediate	(3)
Customer 100	Eastern NC	Solar PV	2.7 kW	Intermediate	(3)
Customer 101	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 102	Eastern NC	Solar PV	2 kW	Intermediate	(3)
Customer 103	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 104	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 105	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 106	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 107	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 108	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 109	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 110	Eastern NC	Solar PV	4 kW	Intermediate	(3)
Customer 111	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 112	Eastern NC	Solar PV	4 kW	Intermediate	(3)
Customer 113	Eastern NC	Solar PV	1 kW	Intermediate	(3)
Customer 114	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 115	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 116	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 117	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 118	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 119	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 120	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 121	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 122	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 123	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 124	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 125	Eastern NC	Solar PV	5 kW	Intermediate	(3)
Customer 126	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 127	Eastern NC	Solar PV	2 kW	Intermediate	(3)
Customer 128	Eastern NC	Solar PV	5 kW	Intermediate	(3)
Customer 129	Eastern NC	Solar PV	8 kW	Intermediate	(3)

Customer 130	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 131	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 132	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 133	Western NC	Solar PV	2 kW	Intermediate	(3)
Customer 134	Western NC	Solar PV	1 kW	Intermediate	(3)
Customer 135	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 136	Western NC	Solar PV	3 kW	Intermediate	(3)
Customer 137	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 138	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 139	Western NC	Solar PV	2 kW	Intermediate	(3)
Customer 140	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 141	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 142	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 143	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 144	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 145	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 146	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 147	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 148	Western NC	Solar PV	4 kW	Intermediate	(3)
Customer 149	Western NC	Solar PV	7 kW	Intermediate	(3)
Customer 150	Western NC	Solar PV	3 kW	Intermediate	(3)
Customer 151	Western NC	Solar PV	1 kW	Intermediate	(3)
Customer 152	Western NC	Solar PV	1 kW	Intermediate	(3)
Customer 153	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 154	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 155	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 156	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 157	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 158	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 159	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 160	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 161	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 162	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 163	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 164	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 165	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 166	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 167	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 168	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 169	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 170	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 171	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 172	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 173	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 174	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 175	Eastern NC	Solar PV	N/A	Intermediate	(3)

Customer 176	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 177	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 178	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 179	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 180	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 181	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 182	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 183	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 184	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 185	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 186	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 187	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 188	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 189	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 190	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 191	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 192	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 193	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 194	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 195	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 196	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 197	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 198	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 199	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 200	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 201	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 202	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 203	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 204	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 205	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 206	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 207	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 208	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 209	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 210	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 211	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 212	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 213	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 214	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 215	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 216	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 217	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 218	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 219	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 220	Eastern NC	Solar PV	N/A	Intermediate	(3)
Customer 221	Western NC	Solar PV	N/A	Intermediate	(3)

Customer 222	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 223	Western NC	Solar PV	N/A	Intermediate	(3)
Customer 224	Western NC	Solar PV	N/A	Intermediate	(3)
		SOUTH CAROLINA GENERATORS			
Customer 225	South Carolina	Fossil Coal	28,000 kW	Baseload	(1)
Customer 226	South Carolina	Process By-product & Coal	73,000 kW	Baseload	(1)
Customer 227	South Carolina	Process By-product	27,000 kW	Baseload	(1)
Customer 228	South Carolina	Diesel Fuel	1,500 kW	Peaking	(2)
Customer 229	South Carolina	Diesel Fuel	1,500 kW	Peaking	(2)
Customer 230	South Carolina	Solar PV	N/A	Intermediate	(3)
Customer 231	South Carolina	Diesel Fuel	350 kW	Peaking	(2)
Customer 232	South Carolina	Solar PV	N/A	Intermediate	(3)
Customer 233	South Carolina	Solar PV	N/A	Intermediate	(3)

NOTES:

(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.

Individual Wholesale Customer Forecasts

	French Broad MW	Camden MW	Waynesville MW	Winterville MW	Tritowns MW	Haywood MW	NCEMPA MW	Piedmont MW	Fayetteville MW	NCEMC Total MW	Wholesale	NCEMC Firm MW
2012	84	51	15	12	19	19	1,350	21	452	1,012	3,035	200
2013	90	51	17	12	19	20	1,359	22	458	2,107	4,156	150
2014	90	52	17	12	19	20	1,370	23	464	2,138	4,205	150
2015	91	52	18	12	19	20	1,379	23	470	2,167	4,252	150
2016	92	53	18	12	19	21	1,387	24	476	2,195	4,296	150
2017	93	53	18	12	19	22	1,391	25	483	2,228	4,344	150
2018	94	54	18	12	-	23	1,397	25	489	2,264	4,376	150
2019	95	54	18	13	-	24	1,404	26	495	2,301	4,429	150
2020	95	55	18	13	-	34	1,411	27	501	2,341	4,495	150
2021	96	55	19	13	-	40	1,418	28	507	2,378	4,552	150
2022	97	56	19	13	-	40	1,424	28	513	2,411	4,601	150
2023	98	56	19	13	-	40	1,432	28	519	2,456	4,661	150
2024	99	57	19	13	-	41	1,440	29	525	2,489	4,711	150
2025	100	57	19	13	-	41	1,448	29	530	2,529	4,767	-
2026	101	58	19	13	-	42	1,457	30	536	2,575	4,831	-
2027	102	58	20	13	-	42	1,466	30	542	2,614	4,886	-

Requests for Proposals

PEC did not issue any Requests for Proposals (RFPs) for purchased power since its last biennial report. PEC did, however, issue two RFPs in July 2011 for renewable generation to meet Senate Bill 3 compliance requirements, which are discussed in Appendix D.

Progress Energy Carolinas

Integrated Resource Plan

Appendix D
Alternative Supply Resources
NC REPS Compliance Plan

November 2012

PROGRESS ENERGY CAROLINAS, INC.'S
2012 REPS COMPLIANCE PLAN

TABLE OF CONTENTS

I. INTRODUCTION

Progress Energy Carolinas, Inc. ("Progress Energy Carolinas" or the "Company" or "PEC") submits its annual Renewable Energy and Energy Efficiency Portfolio Standard ("NC REPS" or "REPS") Compliance Plan ("Compliance Plan") in accordance with N.C. Gen. Stat. § 62-133.8 and North Carolina Utilities Commission (the "Commission") Rule R8-67(b). This Compliance Plan, set forth in detail in Section II through Section IX, provides the required information and outlines the Company's projected plans to comply with NC REPS for the period 2012 to 2014 ("the Planning Period").[1]

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

Progress Energy Carolinas calculates its NC REPS Compliance Obligations for the Planning Period based on its actual and forecasted retail sales, as well as the actual and forecasted retail sales of those wholesale customers for whom the Company is supplying REPS compliance. The Company's wholesale customers for which it supplies REPS compliance services are the City of Waynesville, the Town of Sharpsburg, the Town of Stantonsburg, the Town of Black Creek, and the Town of Lucama (collectively referred to as "Wholesale" or "Wholesale Customers"). Table 1 below shows the Company's retail and Wholesale customers' REPS Compliance Obligation.

Table 1: Progress Energy Carolinas' NC REPS Compliance Obligation

Compliance Year	Previous Year PEC Retail Sales	Previous Year Wholesale Customers' Retail Sales	Total Retail Sales for REPS Compliance	Solar Set-Aside (RECs)	Swine Set-Aside (RECs)	Poultry Set-Aside (RECs)	REPS Require-ment (%)	REPS Compliance Obligation (RECs)
2012	37,353,311	155,584	37,508,895	26,256	26,256	49,354	3%	1,125,267
2013	36,868,966	155,568	37,024,535	25,917	25,917	203,224	3%	1,110,736
2014	37,255,920	155,982	37,411,902	26,188	26,188	261,288	3%	1,122,357

Note: Annual compliance REC requirements are determined based on prior-year MWh sales. MWh sales presented above are for compliance years 2012 – 2014 and represent actual MWh sales for 2011, and projected MWh sales for 2012 and 2013, respectively.

PEC is constantly evaluating options to meet its overall requirements. Under G.S. § 62-133.8 (b), opportunities to meet the REPS requirements can be categorized as follows: PEC ownership of or purchases from new renewable energy generation; the use of renewable energy resources at generating facilities; purchases of renewable energy certificates (RECs); and implementation of energy efficiency measures.

[1] Pursuant to Commission Rule R8-67(b)(1), this Compliance Plan reflects Progress Energy Carolinas' present planning efforts to meet the REPS requirements for the current year and immediately subsequent two calendar years.

With regard to utility ownership of new renewable energy facilities, PEC does not own or operate new renewable generating facilities, however, PEC does evaluate the ownership of new renewable energy facilities as described in the Screening of Generation Alternatives portion of this IRP. As with ownership of any new generation, future direct or partial ownership of new renewable energy generating facilities is dependent upon cost-effectiveness and portfolio requirements.

PEC engages in ongoing research regarding the use of alternative fuels meeting the definition of renewable energy resources at its existing generation facilities. Introducing alternative fuels in traditional power plants must prove to be 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 new renewable energy facilities, PEC has adopted a competitive bidding and evaluation process whereby market participants have an opportunity to propose projects on a continuous basis. PEC maintains an open RFP for non-solar projects less than 10 MWs in size. In addition, PEC from time-to-time issues resource specific RFPs, as needed to meet Senate Bill 3 obligations. Through the renewable RFP process, since November 2007, PEC has executed a significant number of contracts for solar, hydro, biomass, landfill gas and out of state wind RECs, as shown on Exhibit A.

PEC has purchased out-of-state wind and solar RECs as allowed by Senate Bill 3. These RECs are some of the most cost effective options available, and they will allow PEC to balance its compliance each year while also helping to mitigate vendor performance risk.

PEC is using energy efficiency (EE) measures and programs to comply with a portion of the Senate Bill 3 requirements. A discussion of existing and proposed programs is included in the demand-side management (DSM) and EE section in Appendix E of the IRP. Table 2 below shows the projected MWhs reduced by the incremental EE programs. The EE MWhs are limited to 25% for the Planning Period, and any EE MWhs that exceed the specified cap in any given year will be banked and used in future compliance years.

Table 2: Progress Energy Carolina's Energy Efficiency Forecast

Compliance Year	Energy Efficiency Forecast	Allowed Energy Efficiency for REPS Compliance (%)	PEC REPS Requirement (RECs)	Allowed Energy Efficiency for REPS Compliance (REC Equivalent)	Energy Efficiency Banked for Future Compliance (REC Equivalent)
2012	505,081	25%	1,120,599	280,150	224,931
2013	678,740	25%	1,106,069	276,517	402,222
2014	848,132	25%	1,117,678	279,419	568,712

Progress Energy Carolinas is well positioned to meet the general REPS compliance obligation. The Company has executed numerous contracts; continues to solicit additional proposals for renewable projects; has purchased RECs from numerous projects, some of which began producing RECs in 2008; has implemented energy efficiency programs, which began producing RECs in 2008; and has executed agreements with several projects for out-of-state wind and solar RECs. Table 3 below displays Progress Energy Carolinas' projected compliance with the general REPS requirement. The Contracted Purchases represent expected deliveries from projects under contract. The Undesignated Resources shows the estimated number of additional RECs that PEC needs to secure to be compliant with its pro-rata share of the swine and poultry requirements, as described below.

Table 3: PEC Compliance with the Total REPS Compliance Obligation

Compliance Year	2012	2013	2014
Contracted Purchases	[redacted]	[redacted]	[redacted]
Undesignated Resources	[redacted]	[redacted]	[redacted]
Energy Efficiency	280,150	276,517	279,419
Total Supply Resources and EE (RECs)	[redacted]	[redacted]	[redacted]
REPS Requirement (RECs)	1,125,267	1,110,736	1,122,357
Over or (Under) Supply of Resources Relative to Requirement (RECs)	[redacted]	[redacted]	[redacted]
Beginning REC Balance (Dec 31, 2011) RECs Added (Removed) Ending REC Balance	[redacted]	[redacted]	[redacted]

III. 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, as described above, have agreements with PEC whereby PEC will obtain the RECs necessary for the wholesale customer's compliance. Table 1 shows the load and associated REPS requirement for these wholesale customers. In addition, Table 10 includes the anticipated premium cap for these wholesale customers.

PEC continues to refine development of the overall process to comply on behalf of these wholesale customers. The costs associated with renewable resources procured to comply with the combined retail loads of PEC and the wholesale customers are included in PEC's compliance plan and will be allocated across the total RECs 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.

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

In order to achieve compliance with the initial solar set-aside requirements, PEC has executed a number of solar contracts, as listed on Exhibit A. In addition to these contracts, PEC has maintained a commercial PV program since July 2009 that has a target of adding five (5) MWs of grid-tied solar PV per year. PEC also implemented a residential PV program on January 1, 2011 with a target of adding one (1) MW per year of distributed solar generation. PEC issued a solar RFP in June 2011 for grid-connected projects ranging in size from one (1) to three (3) MW. This RFP resulted in [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. Table 4 shows the solar set-aside requirement. The Contracted Solar column shows the anticipated production from both contracted PV and solar thermal projects that vary in technology, size, and geographic location.

Table 4: Compliance with the Solar Set-Aside

Compliance Year	Solar Set-Aside Requirement (RECs)	Contracted Solar (RECs)	Delta with Requirement (RECs)	Beginning Solar REC Position (RECs)	Ending Solar REC Position (RECs)
2012	26,256	[redacted]	[redacted]	[redacted]	[redacted]
2013	25,917	[redacted]	[redacted]	[redacted]	[redacted]
2014	26,188	[redacted]	[redacted]	[redacted]	[redacted]

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

On February 12, 2010, in Docket E-100, Sub 113, the Commission issued an Order approving the issuance of a joint RFP as a means for the state's electric power suppliers to work together to collectively meet the swine waste resource set-aside. The state's electric power suppliers ("Swine REC Buyers Group") issued a joint RFP for swine waste generation on February 15, 2010. Through this RFP, PEC executed [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] contracts. Project developers estimated that they would collectively build as many as [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]swine waste-to-energy facilities throughout North Carolina and that total REC production would exceed the statewide aggregate Swine Set-Aside requirement for 2012 and 2013. In the spring of 2012, the Swine REC Buyers Group terminated [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] contracts for reasons including consistent failure to develop the project, inability to assign the contract to another developer, and consistent failure to demonstrate progress toward commercial operation. After terminating these contracts, PEC has [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL], as shown on Exhibit A. As described in the Amended Joint Motion in Docket No. E-100, Sub 113 filed July 17^{th}, 2012, PEC and other electric power suppliers are seeking to delay the swine and poultry waste set-aside requirement of N.C. Gen. Stat. §§ 62-133.8 (e) and (f), respectively, by two years to allow additional time to meet compliance with these requirements ("Amended Joint Motion"). Table 5 below shows the swine set-aside requirement. The Contracted Swine column shows the number of swine RECs PEC has under contract and expects to receive by year. The Undesignated Swine column shows the estimated number of additional RECs that PEC needs to secure to be compliant with the 2014 swine requirement.

Table 5: Compliance with the Swine Set-Aside

Compliance Year	Swine Set-Aside Requirement (RECs)	Contracted Swine (RECs)	Undesignated Swine (RECs)	Total Swine Resources (RECs)
2012	26,256	[redacted]	[redacted]	[redacted]
2013	25,917	[redacted]	[redacted]	[redacted]
2014	26,188	[redacted]	[redacted]	[redacted]

VI. <u>G.S. § 62-133.8(f)</u>: COMPLIANCE WITH REPS REQUIREMENT THROUGH USE OF POULTRY WASTE RESOURCES

As described in the Amended Joint Motion in Docket No. E-100, Sub 113 filed July 17th, 2012, PEC and other electric power suppliers are seeking to delay the swine and poultry waste set-aside requirement of N.C. Gen. Stat. §§ 62-133.8 (e) and (f), respectively, by two years to allow additional time to meet compliance with these requirements ("Amended Joint Motion"). The statewide requirement for poultry waste is 170,000 RECs in 2012, 700,000 RECs in 2013, and 900,000 RECs in 2014. PEC projects its pro-rata requirement for 2012 is 49,354 RECs, PEC's requirement in 2015 is approximately 203,000 RECs, and PEC's requirement in 2016 is approximately 261,000 RECs. In July 2010, PEC joined with other electric suppliers and issued a Joint Poultry RFP, resulting in [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. Table 6 below shows the poultry set-aside requirement. The Contracted Poultry column shows the projection of the RECs PEC will receive under these contracts. The Undesignated Poultry column shows the estimated number of additional RECs that PEC needs to secure to be compliant with its pro-rata share of the 170,000 statewide requirement by 2014.

Table 6: Compliance with the Poultry Set-Aside

Compliance Year	Poultry Set-Aside Requirement (RECs)	Contracted Poultry (RECs)	Undesignated Poultry (RECs)	Total Poultry Resources (RECs)

2012	49,354		[redacted]			[redacted]			[redacted]	
2013	203,224		[redacted]			[redacted]			[redacted]	
2014	261,288		[redacted]			[redacted]			[redacted]	

VII. CURRENT AND PROJECTED AVOIDED COST RATES

The current and projected avoided cost rates represent the annualized avoided cost rates for Cogeneration and Small Power Producer (CSP) Schedule CSP-27, approved in the Commission Order issued in Docket No. E-100, Sub 127 in August 2011.

Table 7: Annualized Capacity and Energy Rates (cents per KWh)

	2012 (Current)	2013 (Projected)	2014 (Projected)
Variable Rate	5.786¢	5.786¢	5.786¢
5 Year	6.184¢	6.184¢	6.184¢
10 Year	6.816¢	6.816¢	6.816¢
15 Year	7.286¢	7.286¢	7.286¢

VIII. PROJECTED TOTAL NORTH CAROLINA RETAIL AND WHOLESALE SALES AND YEAR-END NUMBER OF CUSTOMER ACCOUNTS BY CLASS

The tables below show the actual and projected retail sales for PEC and the Wholesale Customers.

Table 8: Retail Sales for Retail and Wholesale Customers

year	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast
Retail MWh Sales	37,353,311	36,868,966	37,255,920	37,708,885
Wholesale MWh Sales	155,584	155,568	155,982	156,398
Total MWh Sales	37,508,895	37,024,535	37,411,902	37,865,283

Table 9: Retail and Wholesale Year-end Number of Customer Accounts

year	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast
Residential Accts	1,115,346	1,126,564	1,137,912	1,151,075
General Accts	181,666	185,011	188,420	192,762
Industrial Accts	2,069	2,090	2,110	2,131

IX. PROJECTED ANNUAL COST CAP COMPARISON OF TOTAL AND INCREMENTAL COSTS, REPS RIDER, AND FUEL COST IMPACT

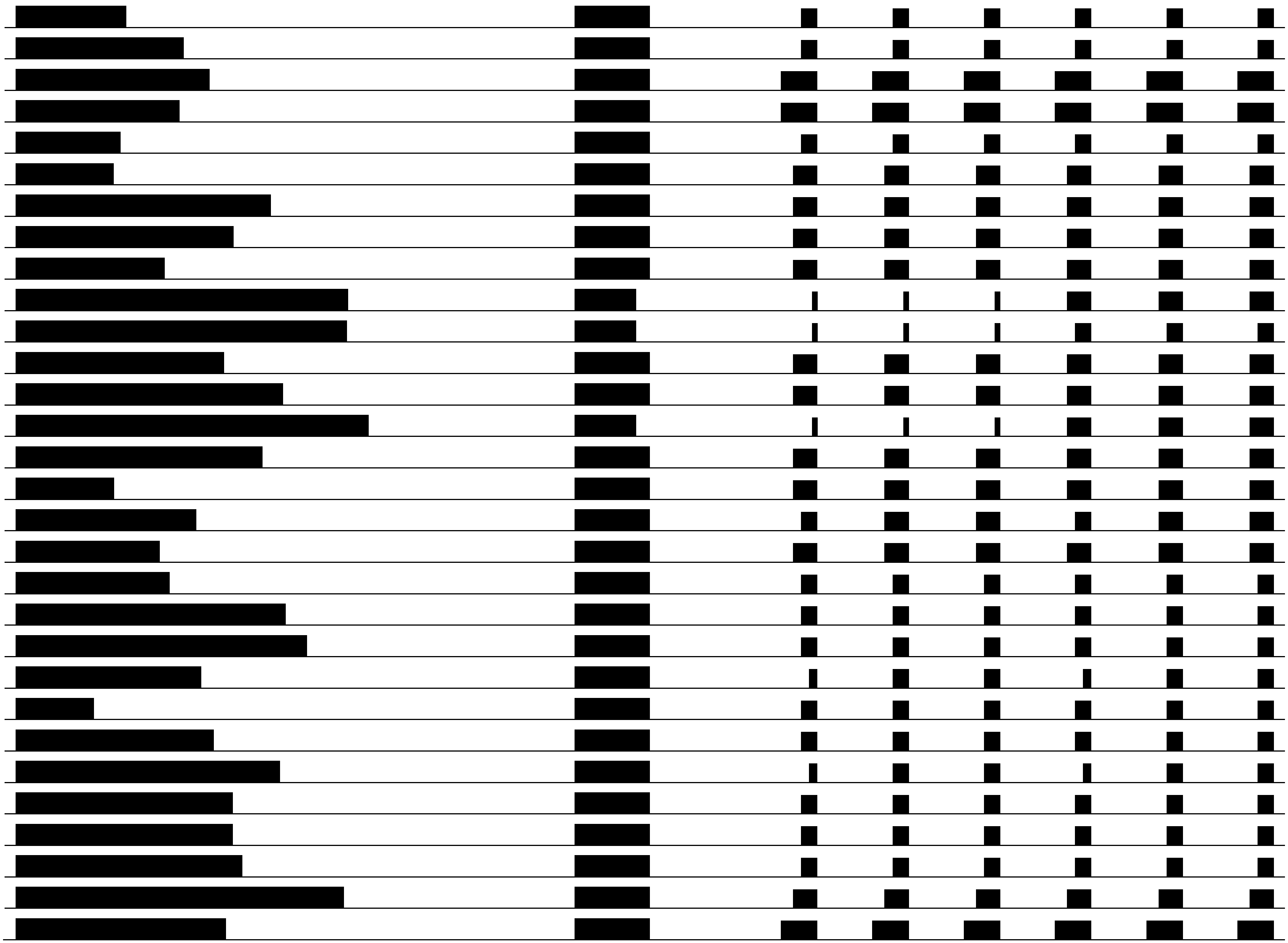
Table 10 shows the projected compliance costs for contracted resources by calendar year. The cost cap data is based on the number of accounts as reported above.

Table 10: Projected Annual Cost Caps, Fuel Related Cost Impact, Annual REPS Rider

year	2012	2013	2014
Total projected REPS compliance costs	$126,663,218	$131,011,101	$134,861,111
Recovered through the Fuel Rider	$106,186,016	$110,855,709	$112,221,355
Total Incremental costs (REPS Rider)	$20,477,202	$20,155,392	$22,639,757
Total Including GRT and Regulatory Fee	$21,184,773	$20,851,843	$23,422,053
Projected Annual Cost Caps (REPS Rider)	$42,703,052	$43,360,012	$44,028,334
Unused Available Premium	$21,518,279	$22,508,168	$20,606,281

[BEGIN CONFIDENTIAL]
EXHIBIT A: Progress Energy Carolinas' Renewable Resource Procurement from 3rd Parties (signed contracts as of July 31, 2012)

[redacted]	[redacted]						
	* Indicates bundled purchase including energy	2012	2013	2014	2012	2013	2014
[redacted]							
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]



[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Progress Energy Carolinas

Integrated Resource Plan

Appendix E
Demand Side Management and Energy Efficiency

November 2012

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

Progress Energy Carolinas, Inc. (PEC) continues to pursue a long-term, balanced capacity and energy strategy to meet the future electricity needs of its customers. This balanced strategy includes a strong commitment to demand side management (DSM) and energy efficiency (EE) programs, investments in renewable and emerging energy technologies, and state-of-the art power plants and delivery systems. PEC's DSM/EE portfolio currently consists of the following programs, all of which have been approved by the Public Service Commission of South Carolina (PSCSC) and all but three have also received approval from the North Carolina Utilities Commission (NCUC).

- Residential Home Energy Improvement
- Residential Home Advantage *(Closed to New Participants)*
- Residential New Construction *(Approved in South Carolina only)*
- Residential Neighborhood Energy Saver (Low-Income)
- Residential Lighting Program
- Residential Appliance Recycling Program
- Residential Energy Efficient Benchmarking Program
- Commercial, Industrial, and Governmental (CIG) Energy Efficiency
- Small Business Energy Saver *(Approved in South Carolina only)*
- Residential EnergyWise Home℠
- CIG Demand Response Automation Program
- Distribution System Demand Response (DSDR) Program
- Residential Prepay Pilot Program *(Approved in South Carolina only)*

DSM/EE Program Descriptions

Residential Home Energy Improvement Program
Program Type: Energy Efficiency

The Residential Home Energy Improvement Program offers PEC customers a variety of energy conservation measures designed to increase energy efficiency for existing residential dwellings that can no longer be considered new construction. The prescriptive menu of energy efficiency measures provided by the program allows customers the opportunity to participate based on the needs and characteristics of their individual homes. Financial incentives are provided to participants for each of the conservation measures promoted within this program. The program utilizes a network of pre-qualified contractors to install each of the following energy efficiency measures:

- High-Efficiency Heat Pumps and Central A/C
- Duct Repair
- Level-2 HVAC Tune-up

- Insulation Upgrades/Attic Sealing

Recently approved measures that have been added to the program's portfolio since PEC's last IRP filing includes:

- High Efficiency Room Air Conditioners – to encourage residential customers to improve the efficiency of their home by replacing inefficient room air conditioners with Energy Star certified room air conditioners.
- Heat Pump Water Heater – to encourage residential customers to improve the efficiency of their home by replacing inefficient water heaters with high efficiency water heaters having a minimum energy factor of 2.0.

The Residential Home Energy Improvement program was launched in July 2009. Through June 30, 2012, there have been 66,061 participants contributing 16,302 MWh in net annualized energy savings and 15,373 kW in peak demand savings.

Residential Home Advantage Program

Program Type: Energy Efficiency

The Residential Home Advantage Program has been closed to new participants since March 1, 2012, as PEC is planning to implement a new program based on the 2012 North Carolina Energy Conservation Code. The Residential Home Advantage Program offered developers and builders the potential to maximize energy savings in various types of new residential construction. The program utilized a prescriptive approach for developers and builders of projects for single-family, multi-family (three stories or less), and manufactured housing units (SC only). The program was also available to high rise multi-family units not eligible for ENERGY STAR® as long as each unit met the intent of the ENERGY STAR® builder option package for their climate zone and the Home Advantage Program criteria.

The primary objectives of this program were to reduce system peak demands and energy consumption within new homes. New construction represents a unique opportunity for capturing cost effective EE savings by encouraging the investment in energy efficiency features that would otherwise be impractical or more costly to install at a later time. These are often referred to as lost opportunities.

Since the launch of the Residential Home Advantage program in December 2008, there have been 6,871 participants through June 30, 2012, contributing 8,253 MWh in net annualized energy savings and 2,656 kW in peak demand savings.

Residential New Construction Program *(Approved in South Carolina only as of August 1, 2012)*
Program Type: Energy Efficiency

The Residential New Construction program serves as a replacement for the Residential Home Advantage program which was closed to new applications effective March 1, 2012. The Residential New Construction Program offers incentives to both single family builders and multi-family developers who install energy efficient equipment or build to the energy efficient standards required by the program. Builders and Developers may elect to receive incentives for the installation of heat pump water heaters and/or high efficiency HVAC equipment; or they may elect to receive incentives for exceeding the residential requirements of the 2012 North Carolina Energy Conservation Code. They also have the option to receive incentives for the equipment measures implemented, or the whole house measures implemented, but not both.

The primary objectives of this program are to reduce system peak demands and energy consumption within new homes. New construction represents a unique opportunity for capturing cost effective EE savings by encouraging the investment in energy efficiency features that would otherwise be impractical or more costly to install at a later time. These are often referred to as lost opportunities.

As of August 1, 2012 the Residential New Construction program has been approved in South Carolina but has not yet been implemented. The program has not yet been approved in North Carolina.

Residential Neighborhood Energy Saver (Low-Income) Program
Program Type: Energy Efficiency

PEC's Neighborhood Energy Saver Program assists low-income residential customers with energy conservation efforts which will in turn lessen their household energy costs. The program provides assistance to low-income families by installing a comprehensive package of energy conservation measures that lower energy consumption at no cost to the customer. Prior to installing measures, an energy assessment is conducted on each residence to identify the appropriate measures to install. In addition to the installation of energy efficiency measures, an important component of the Neighborhood Energy Saver program is the provision for one-on-one energy education. Each household receives information on energy efficiency techniques and is encouraged to make behavioral changes to help reduce and control their energy usage. The Neighborhood Energy Saver program is being implemented utilizing a whole neighborhood, door-to-door delivery strategy.

As of June 30, 2012, measures have been installed in 12,506 homes. These installed measures contributed 11,620 MWh in net annualized energy savings and 1,791 kW in peak demand savings.

Residential Lighting Program

Program Type: Energy Efficiency

The Residential Lighting Program is designed to reduce energy consumption by providing incentives and marketing support through retailers to encourage greater PEC customer adoption of ENERGY STAR® qualified or other high efficiency lighting products. The program targets the purchase of these products through in-store and on-line promotions, while promoting greater awareness through special retail and community events. The program initially focused on compact fluorescent light bulbs (CFLs), with the intent to add newer lighting technologies as they mature. PEC partners with various manufacturers and retailers across its entire service territory to offer a wide selection of these high efficiency products to its customers.

Through June 30, 2012, 7,668,680 CFLs have been sold through the Residential Lighting Program, contributing 179,146 MWh in net annualized energy savings and 17,200 kW in peak demand savings.

Prior to implementation of the Residential Lighting Program, PEC ran a CFL Buy-Down Pilot during the last quarter of 2007 which accounted for 203,222 bulbs sold and contributed 6,706 MWh in annualized net energy savings and 630 kW in peak demand savings.

Residential Appliance Recycling Program

Program Type: Energy Efficiency

The Appliance Recycling Program is designed to reduce energy consumption and provide environmental benefits through the proper removal and recycling of older, less efficient refrigerators and freezers that are operating within residences across the PEC service territory. The program includes scheduling and free appliance pick-up at the customer's location, transportation to a recycling facility, and recovery and recycling of appliance materials. On an annual basis, customers receive free removal and recycling of up to two appliances, as well as an incentive for participation.

The Residential Appliance Recycling Program was launched in April 2010. As of June 30, 2012, there have been 17,274 participants contributing 12,624 MWh in net annualized energy savings and 1,462 kW in peak demand savings.

Residential Energy Efficient Benchmarking Program

Program Type: Energy Efficiency

The Residential Energy Efficient Benchmarking Program is designed to reduce residential electrical consumption by applying behavioral science principals in which a sample of eligible customers receive reports comparing their energy use with neighbors in similar homes. Participants will be periodically mailed the individualized reports and can elect to switch to on-line reports at any time during the duration of the program. In addition to the household comparative analysis, the reports will provide specific recommendations to motivate participants to reduce their energy consumption. PEC will also deploy an interactive web portal that gives customers greater insight into their energy consumption and actions they can take to become more energy efficient. The web portal will include monthly customer billing data, goal setting and tracking, as well as personalized and community recommended energy efficiency tips.

The Residential Energy Efficient Benchmarking Program was launched in July 2011. As of June 30, 2012, there have been 46,228 participants contributing 13,314 MWh in net annualized energy savings and 2,390 kW in peak demand savings.

Commercial, Industrial, and Governmental (CIG) Energy Efficiency Program

Program Type: Energy Efficiency

The CIG Energy Efficiency Program is available to all CIG customers interested in improving the energy efficiency of their new construction projects or within their existing facilities. New construction incentives provide an opportunity to capture cost effective energy efficiency savings that would otherwise be impractical or more costly to install at a later time. The retrofit market offers a potentially significant opportunity for savings as CIG type customers with older, energy inefficient electrical equipment are often under-funded and need assistance in identifying and retrofitting existing facilities with new high efficiency electrical equipment. The program includes prescriptive incentives for measures that address the following major end-use categories:

- HVAC
- Lighting
- Refrigeration

In addition, the program offers incentives for custom measures to specifically address the individual needs of customers in the new construction or retrofit markets, such as those with more complex applications or in need of energy efficiency opportunities not covered by the prescriptive measures. The program also seeks to meet the following overall goals:

- Educate and train trade allies, design firms and customers to influence selection of energy efficient products and design practices.
- Educate CIG customers regarding the benefits of energy efficient products and design elements 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 measureable.
- Influence market transformation by offering incentives for cost effective measures.

The CIG Energy Efficiency program was launched in April 2009. As of June 30, 2012, there have been 2,413 participants contributing 109,718 MWh in net annualized energy savings and 25,108 kW in peak demand savings.

Small Business Energy Saver Program *(Approved in South Carolina only as of August 1, 2012)*
Program Type: Energy Efficiency

The Small Business Energy Saver Program is a new direct-install type of program designed to encourage the installation of energy efficiency measures in small, "hard to reach" commercial facilities within an annual energy demand of less than 100 kW. The program provides a complete energy assessment and installation of measures on a turn-key basis. In addition, the program was designed to minimize financial barriers by incorporating aggressive incentives as well as providing payment options for the remainder of participant costs.

As of August 1, 2012 the Small Business Energy Saver program has been approved in South Carolina but has not yet been implemented. The program has not yet been approved in North Carolina.

Residential EnergyWise Home℠ Program
Program Type: Demand Response

The Residential EnergyWise Home℠ Program is a direct load control program that allows 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 is provided to program participants in exchange for allowing PEC to control the listed appliances. Effective June 20, 2012, availability of the EnergyWise Home℠ program was expanded to include customers who do not own their own residences and have consent of the owner.

The program provides PEC with the ability to reduce and shift peak loads, thereby enabling a corresponding deferral of new supply-side peaking generation and enhancing system reliability.

Participating customers are impacted by (1) the installation of load control equipment at their residence, (2) load control events which 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.

Through June 30, 2012, the Residential EnergyWise Home℠ Program has 87,416 participants contributing 98,380 kW of summer peak load reduction capability and 5,370 kW of winter peak load reduction capability. The following table shows Residential EnergyWise Home℠ Program activations that were not for testing purposes from August 1, 2010 through July 31, 2012.

Residential EnergyWise Home℠			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
8/11/2010 15:00	8/11/2010 18:00	180	40.8
5/31/2011 16:00	5/31/2011 17:30	90	71.5
6/1/2011 16:00	6/1/2011 18:00	120	58.9
7/12/2011 15:00	7/12/2011 18:00	180	76.0
7/22/2011 15:00	7/22/2011 17:30	150	82.0
7/29/2011 15:00	7/29/2011 17:30	150	82.9
8/4/2011 15:00	8/4/2011 18:00	180	69.9
8/8/2011 15:00	8/8/2011 18:00	180	72.9
1/4/2012 6:30	1/4/2012 9:30	180	5.0
2/13/2012 6:00	2/13/2012 8:30	150	5.2
5/2/2012 15:30	5/2/2012 17:30	120	72.3
7/6/2012 15:00	7/6/2012 17:00	120	97.1
7/26/2012 15:00	7/26/2012 18:00	180	101.0

Commercial, Industrial, and Governmental (CIG) Demand Response Automation Program
Program Type: Demand Response

The CIG Demand Response Automation Program allows PEC to install load control and data acquisition devices to remotely control and monitor a wide variety of electrical equipment capable of serving as a demand response resources. This goal of this program is to utilize customer education, enabling two-way communication technologies, and an event-based incentive structure to maximize load reduction capabilities and resource reliability. The primary objective of this program is to reduce PEC's need for additional peaking generation. This will be accomplished by reducing PEC's seasonal peak load demands, primarily during the summer months, through deployment of load control and data acquisition technologies.

The CIG Demand Response Automation Program was launched in October 2009. As of June 30, 2012, there were 31 active installations in the program contributing 13,468 kW of available load reduction capability. The table below shows information for each CIG Demand Response Automation Program non-test control event from August 1, 2010 through July 31, 2012.

CIG Demand Response Automation			
Start Time	**End Time**	**Duration (Minutes)**	**MW Load Reduction**
8/11/2010 13:00	8/11/2010 19:00	360	5.2
12/15/2010 6:00	12/15/2010 10:00	240	1.0
7/12/2011 13:00	7/12/2011 19:00	360	13.5
7/22/2011 13:00	7/22/2011 19:00	360	15.3
8/8/2011 13:00	8/8/2011 19:00	360	14.9
1/4/2012 6:00	1/4/2012 9:00	180	1.3
7/6/2012 13:00	7/6/2012 18:00	300	14.1
7/26/2012 13:00	7/26/2012 19:00	360	15.5

Distribution System Demand Response Program (DSDR)

Program Type: Energy Efficiency in North Carolina; Demand Response in South Carolina

PEC and other utilities have historically utilized conservation voltage reduction to reduce peak demand for short periods of time by lowering system voltage. This practice has been used in a limited fashion due to concerns that some customers could experience voltages below the lowest allowable level. The DSDR program is an application of Smart Grid technology that provides the capability to reduce peak demand for four to six hours at a time, which is the duration consistent with typical peak load periods, while also maintaining customer delivery voltage above the minimum requirement when the program is in use. The increased peak load reduction capability and flexibility associated with DSDR will result in the displacement of the need for additional peaking generation capacity. This capability is accomplished by investing in a robust system of advanced technology, telecommunications, equipment, and operating controls. This increased peak load reduction is accomplished while maintaining customer delivery voltage above the minimum requirements. 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 Prepay Pilot Program (South Carolina only)

Program Type: Energy Efficiency

The primary objectives of the Prepay Pilot are to measure and validate the achieved energy and capacity savings resulting from offering customers a prepaid payment option, and to better understand the drivers and persistence behind the associated energy savings. Similar programs report energy savings from 10% - 15%. The Prepay Pilot will also help PEC to determine the market for Prepay, examine customer behavior while on Prepay, determine customer motives, and evaluate customer preferences regarding payment channels and communication methods.

Enrollment in this pilot program would initially be provided to a limited number of residential customers in predetermined geographies. Some participants may receive in-home displays, and all participants would have access to a web portal and 24/7 cash pay locations. Additionally, all participants would have access to multiple communication channels including phone, email, and text messaging.

Summary of Prospective Program Opportunities

PEC is continually seeking to enhance its DSM/EE portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results, and (3) other EE research & development pilots. The following projects represent program enhancements that are currently underway and expected to be implemented within the biennium for which this IRP is filed.

- Residential Lighting Program – PEC is planning to broaden the availability of measures provided under its Residential Lighting Program to include other types of high efficiency lighting technologies, such as LEDs, 2X incandescents and CFL fixtures.
- Neighborhood Energy Saver Program – PEC is evaluating various options for expanding its existing low-income energy efficiency program including but not limited to consideration of additional measures, broader reaching efforts, and additional delivery/implementation channels. PEC is currently achieving 85% penetration levels in targeted neighborhoods within its Neighborhood Energy Saver program and desires to further build upon this success with additional energy savings enhancements that are in the continued best interest of the company and its customers.
- Residential New Construction Program – PEC has received approval in South Carolina for this replacement to the now closed Residential Home Advantage program and has submitted the program for approval in North Carolina. Program implementation is expected to occur during the latter half of 2012.
- Small Business Energy Saver Program – PEC has received approval for this direct-install EE program in South Carolina and has submitted the program for approval in North Carolina. Program implementation is expected to occur during the latter half of 2012.

DSM and EE Forecasts

Earlier this year PEC commissioned a new energy efficiency market potential study to obtain new estimates of the technical, economic and achievable potential for EE savings within the PEC service area. The final report, “Progress Energy Carolinas: Electric Energy Efficiency Potential Assessment,” was prepared by Forefront Economics Inc. and H. Gil Peach and Associates, LLC and was completed on June 5, 2012. Achievable potential was derived using energy efficiency measure bundles and conceptual program designs to estimate participation, savings and program spending over a 15 year planning period under a specific set of assumptions, which includes the significant effect of certain large commercial and industrial customers “opting-out” of the programs.

The study results are suitable for integrated resource planning purposes and use in long-range system planning models. This study is also expected to help inform utility program planners regarding the extent of EE opportunities and to provide broadly defined approaches for acquiring savings. It did not, however, attempt to closely forecast EE achievements in the short-term or from year to year. Such an annual accounting is highly sensitive to the nature of programs adopted, the timing of the introduction of those programs, and other factors. As a result, it was not designed to provide detailed specifications and work plans required for program implementation. This study provides part of the picture for planning EE programs. Fully implementable EE program plans are best developed considering this study along with the experience gained from currently running programs, input from PEC program managers and EE planners, and with the possible assistance of implementation contractors.

PEC’s forecasts of EE program savings for integrated resource planning purposes are based on the results of the new potential study. The tables below show the projected composite savings of all PEC DSM, EE and DSDR programs implemented since the adoption of North Carolina Senate Bill 3 (SB-3) in 2007. These projections include the expected savings potential from program growth, program enhancements and future new programs. The projections do not include savings from programs that existed prior to SB-3, such as large load Curtailment Rates or Voltage Control, which will be discussed later in this document.

Peak MW Demand Savings for New Post SB-3 DSM/EE (at generator)

Year	Summer Peak MW Savings				Winter Peak MW Savings			
	DSM	EE	DSDR	Total	DSM	EE	DSDR	Total
2013	143	100	236	479	7	55	236	299
2014	164	127	240	530	9	77	240	326
2015	183	154	244	581	9	97	244	351
2016	201	182	249	632	10	116	249	375
2017	217	206	253	676	11	133	253	397
2018	232	227	257	717	12	147	257	416
2019	247	251	261	759	13	164	261	438
2020	260	278	265	803	13	182	265	461
2021	273	306	269	848	14	203	269	485
2022	286	334	273	892	14	222	273	509
2023	297	361	276	934	15	240	276	531
2024	308	386	280	974	15	258	280	553
2025	318	409	284	1,010	16	274	284	573
2026	327	428	288	1,043	16	287	288	591
2027	336	444	292	1,073	16	299	292	608

Annual MWh Energy Savings (at generator)

Year	DSM	EE	DSDR	Total Savings
2013	3,086	626,090	49,563	678,740
2014	3,487	794,297	50,348	848,132
2015	3,854	975,246	51,035	1,030,135
2016	4,195	1,166,761	51,938	1,222,894
2017	4,509	1,319,801	52,787	1,377,097
2018	4,798	1,493,989	53,598	1,552,385
2019	5,078	1,687,953	54,429	1,747,461
2020	5,333	1,894,711	55,239	1,955,283
2021	5,587	2,108,341	55,985	2,169,913
2022	5,815	2,315,124	56,768	2,377,706
2023	6,035	2,514,951	57,534	2,578,520
2024	6,230	2,707,038	58,302	2,771,570
2025	6,418	2,859,983	59,031	2,925,431
2026	6,605	2,997,047	59,872	3,063,524
2027	6,773	3,117,012	60,719	3,184,503

EE Savings Variance

The EE savings forecast of MWh energy is higher in all years than the forecast contained in last year's IRP. A variance greater than ten percent occurs during the years 2016 through 2027, with a maximum variance of 18.5% in 2021. In contrast, the peak MW demand savings forecast from EE programs is lower for all years than the forecast contained in the prior year's IRP, with a variance of greater than ten-percent in the years 2014 through 2027. The variance is primarily attributable to the use of a new EE market potential study. The EE savings forecast from last year's IRP was developed based upon a 2010 update to a March 16, 2009 Potential Study prepared by ICF International, Inc. For this 2012 IRP, however, the new "Electric Energy Efficiency Potential Assessment" prepared by Forefront Economics Inc. and H. Gil Peach and Associates, LLC on June 5, 2012 served as the basis for the EE savings forecast. For example, the two potential studies assume a very different relationship between MWh energy savings and peak MW demand savings, a key reason why PEC's forecast of energy efficiency program savings increased for MWh energy, but generally decreased for peak MW demand savings.

High EE Savings Projection

PEC also prepared a high EE savings projection designed to meet the following Energy Efficiency Performance Targets for five years, as set forth in the December 8,2011 Settlement Agreement between Environmental Defense Fund, the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy, and Duke Energy Corporation, Progress Energy, Inc., and their public utility subsidiaries Duke Energy Carolinas LLC and Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.

- An annual savings target of one percent (1%) of the previous year's retail electricity sales beginning in 2015; and
- A cumulative savings target of seven percent (7%) of retail electricity sales over the five-year time period of 2014-2018.

For the purposes of this IRP the high EE savings projection is being treated as a resource planning sensitivity that will also serve as an aspirational target for future EE plans and programs. The high EE savings projections are well beyond the level of savings attained by PEC over the past couple of years and much higher than the forecasted savings contained in both the old and new EE Potential study. The effort to meet them will require a substantial expansion of PEC's current Commission-approved EE portfolio. New programs and measures must be developed, approved by regulators, and implemented within the next couple of years. More importantly, significantly higher levels of customer participation must be generated requiring considerably larger investments in marketing and awareness, customer incentive levels, and market channel development. Additionally, further flexibility will be required in operating existing programs in order to quickly adapt to changing market conditions, code and standard changes, consumer demands, and emerging technologies.

At this time there is too much uncertainty regarding PEC's ability to gain Commission approval to offer new programs and/or enhance existing programs to risk using the high EE savings projection as the primary basis for developing the 2012 integrated resource plan. However, the high EE savings forecast will be fully evaluated as a planning sensitivity within the resource planning process. PEC expects that as steps are made over time toward actually achieving higher levels of program participation and savings, then the EE savings forecast used for integrated resource planning purposes will continue to be revised in future IRP's to reflect the most realistic projection of EE savings.

Previously Existing Demand Side Management and Energy Efficiency Programs

Prior to the passage of North Carolina Senate Bill 3 in 2007, PEC had a number of DSM/EE programs in place. These programs are available in both North and South Carolina and include the following:

Existing Energy Efficiency Programs

Energy Efficient Home Program

PEC introduced in the early 1980's an 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. Homes that pass an ENERGY STAR® test receive a certificate as well as a 5% discount on the energy and demand portions of their electricity bills. Through December 2011, there were 281,213 dwellings system-wide that qualified for the discount.

Energy Efficiency Financing

PEC began offering energy efficiency financing for its residential customers through its "Home Energy Loan Program" in 1981. Since the last biennial report, energy efficiency financing options have now been integrated within PEC's Residential Home Energy Improvement program.

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 two-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 has 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, at a level that does not adversely impact customer equipment or operations, during periods of capacity constraints in order to reduce system peak demand.

Projected summer peak demand savings for all PEC existing and new DSM/EE programs not embedded in the load forecast are presented in the table below.

Peak MW Demand Savings for All DSM/EE (at generator)

Year	Peak MW Demand Savings			
	Pre SB-3 Programs		Post SB-3 Programs	All DSM/EE Programs
	Curtailable Rates	Voltage Control	DSM/EE/DSDR	
2013	275	74	479	828
2014	275	76	530	881
2015	275	77	581	933
2016	275	79	632	985
2017	275	80	676	1,031
2018	275	81	717	1,073
2019	275	82	759	1,116
2020	275	84	803	1,162
2021	275	85	848	1,208
2022	275	86	892	1,253
2023	275	87	934	1,297
2024	275	89	974	1,338
2025	275	90	1,010	1,375
2026	275	91	1,043	1,409
2027	275	93	1,073	1,441

Summary of Available Existing Demand-Side and Energy Efficiency Programs

The following table provides current information available at the time of this report on PEC's existing DSM/EE programs (i.e., those programs that were in effect prior to January 1, 2008). This information, where applicable, includes program type, capacity, energy, and number of customers enrolled in the program as of the end of 2011, as well as load control activations since those enumerated in PEC's last biennial resource plan. The energy savings impacts of these existing programs are embedded within PEC's load and energy forecasts.

Program Description	Type	Capacity (MW)	Annual Energy (MWH)	Participants	Activations Since Last Biennial Report
Energy Efficiency Programs[1]	EE	484	NA	NA	NA
Real Time Pricing (RTP)[1]	DSM	22	NA	100	NA
Commercial & Industrial TOU[1]	DSM	5	NA	23,708	NA
Residential TOU[1]	DSM	12	NA	29,685	NA
Curtailable Rates	DSM	275	NA	86	1
Voltage Control	DSM	74	NA	NA	93

Since PEC's last biennial resource plan there has been one Large Load Curtailment activation, only affecting the Western Region, which occurred on January 4, 2012 from 6:30 am to 8:30 am and provided a load reduction of approximately 2 MW. Voltage reduction was activated 93 times from August 2010 through July 2012. The following table shows the date, starting and ending time, and duration for each of those voltage reduction activations.

Voltage Reduction		
Start Time	**End Time**	**Duration (Minutes)**
8/2/2010 13:00	8/2/2010 19:00	360
8/3/2010 13:00	8/3/2010 19:01	361
8/4/2010 13:00	8/4/2010 19:00	360
8/6/2010 13:00	8/6/2010 18:59	359
8/9/2010 13:00	8/9/2010 18:59	359
8/13/2010 12:59	8/13/2010 18:59	360
8/16/2010 12:59	8/16/2010 18:59	360
8/17/2010 13:33	8/17/2010 18:59	326
8/18/2010 13:00	8/18/2010 19:00	360
8/20/2010 13:00	8/20/2010 19:00	360
8/23/2010 12:59	8/23/2010 19:00	361
8/26/2010 13:00	8/26/2010 18:59	359
8/30/2010 13:00	8/30/2010 18:59	359
9/1/2010 12:25	9/1/2010 12:31	6
9/5/2010 14:54	9/5/2010 15:05	11
9/8/2010 12:59	9/8/2010 19:00	361
9/9/2010 13:00	9/9/2010 19:00	360
10/7/2010 0:14	10/7/2010 0:29	15

[1] Impacts from these existing programs are embedded within the load and energy forecast.

Voltage Reduction		
Start Time	**End Time**	**Duration (Minutes)**
10/10/2010 11:28	10/10/2010 11:44	16
10/29/2010 8:16	10/29/2010 8:25	9
11/7/2010 14:29	11/7/2010 14:36	7
11/12/2010 16:20	11/12/2010 16:29	9
12/2/2010 23:17	12/2/2010 23:26	9
12/3/2010 6:36	12/3/2010 6:45	9
12/19/2010 23:36	12/19/2010 23:55	19
1/13/2011 6:00	1/13/2011 8:00	120
1/13/2011 18:00	1/13/2011 21:00	180
1/20/2011 6:00	1/20/2011 8:00	120
1/21/2011 8:43	1/21/2011 8:51	8
1/23/2011 1:02	1/23/2011 1:26	24
1/24/2011 6:00	1/24/2011 8:01	121
1/24/2011 17:59	1/24/2011 20:59	180
1/25/2011 6:01	1/25/2011 8:00	119
1/27/2011 18:00	1/27/2011 20:59	179
1/28/2011 6:00	1/28/2011 8:00	120
2/3/2011 6:00	2/3/2011 8:00	120
2/3/2011 18:00	2/3/2011 21:13	193
2/4/2011 6:00	2/4/2011 8:00	120
2/8/2011 18:01	2/8/2011 20:59	178
2/9/2011 6:06	2/9/2011 8:00	114
2/10/2011 18:00	2/10/2011 20:59	179
2/11/2011 6:00	2/11/2011 8:00	120
4/12/2011 10:27	4/12/2011 10:36	9
4/16/2011 18:54	4/16/2011 19:00	6
5/16/2011 14:50	5/16/2011 14:55	5
5/22/2011 21:14	5/22/2011 22:00	46
6/14/2011 13:00	6/14/2011 19:05	365
6/21/2011 13:00	6/21/2011 19:00	360
6/21/2011 23:49	6/21/2011 23:59	10
6/23/2011 13:00	6/23/2011 19:00	360
6/27/2011 13:01	6/27/2011 19:00	359
6/29/2011 13:01	6/29/2011 19:02	361
7/1/2011 22:41	7/1/2011 22:54	13
7/7/2011 13:00	7/7/2011 19:00	360
7/11/2011 13:00	7/11/2011 18:59	359
7/14/2011 13:00	7/14/2011 19:00	360
7/19/2011 12:59	7/19/2011 19:00	361

Voltage Reduction		
Start Time	**End Time**	**Duration (Minutes)**
7/21/2011 12:59	7/21/2011 19:00	361
7/26/2011 15:40	7/26/2011 15:55	15
7/27/2011 13:00	7/27/2011 19:00	360
7/28/2011 13:00	7/28/2011 19:00	360
7/29/2011 19:20	7/29/2011 19:32	12
8/1/2011 13:00	8/1/2011 18:59	359
8/2/2011 12:59	8/2/2011 19:00	361
8/5/2011 14:34	8/5/2011 14:55	21
8/10/2011 13:00	8/10/2011 19:00	360
8/10/2011 20:19	8/10/2011 20:29	10
8/11/2011 13:01	8/11/2011 19:00	359
8/16/2011 13:00	8/16/2011 19:14	374
8/17/2011 13:00	8/17/2011 18:59	359
8/18/2011 13:00	8/18/2011 18:59	359
8/20/2011 9:48	8/20/2011 9:56	8
8/23/2011 13:55	8/23/2011 14:04	9
8/24/2011 12:59	8/24/2011 18:59	360
8/25/2011 13:00	8/25/2011 18:59	359
9/26/2011 11:47	9/26/2011 11:54	7
10/24/2011 18:46	10/24/2011 19:09	23
1/2/2012 7:45	1/2/2012 8:15	30
2/16/2012 17:36	2/16/2012 18:04	28
2/22/2012 23:19	2/22/2012 23:27	8
2/23/2012 10:24	2/23/2012 10:54	30
3/13/2012 17:38	3/13/2012 17:39	1
3/28/2012 15:04	3/28/2012 15:19	15
4/3/2012 8:51	4/3/2012 9:01	10
5/4/2012 20:42	5/4/2012 20:55	13
5/5/2012 17:00	5/5/2012 17:12	12
5/5/2012 19:45	5/5/2012 19:55	10
5/6/2012 20:39	5/6/2012 20:45	6
5/10/2012 11:01	5/10/2012 11:08	7
5/10/2012 18:21	5/10/2012 18:28	7
5/10/2012 18:21	5/10/2012 18:28	7
6/14/2012 13:35	6/14/2012 13:39	4
7/24/2012 14:26	7/24/2012 14:40	14

Smart Grid Impacts

PEC's Distribution System Demand Response (DSDR) Program represents a Smart Grid application that affects the resource plan. A brief description of the DSDR program as well as the system-level summer and winter peak load and annual energy impacts of the program were provided earlier this document. Further detail regarding the program is provided below.

The DSDR Program was designed to provide incremental distribution system-based peak load reduction in a way that meets sustainability, duration, stability and responsiveness requirements. The DSDR initiative delivers incremental demand reduction by lowering system voltage during system peak periods, thereby deferring or eliminating the need to purchase or build more expensive peaking generation, reduce spinning reserves, and lowering overall fuel costs. DSDR Feeder Conditioning improvements also provide a reduction in distribution system electrical losses. To achieve these benefits the DSDR Program utilizes the following technologies:

1. Feeder conditioning – the voltage regulation equipment (regulators, capacitors, load balancing) installed on 1,162 feeders to flatten the voltage profile,
2. Grid System Design – the sensors & intelligent controls installed on equipment (regulators, capacitors) & T/D substations (regulators, Remote Terminal Units) to retrieve system data & enable remote control commands,
3. IT Systems & Integration – the computer hardware and software systems required to collect/process information and execute commands to control the equipment, and
4. Telecom – the system for connecting sensors, controls, and DMS with two-way communications.

PEC has established a standard, statistical-based methodology that can accurately demonstrate the dependability of DSDR as a peak load reduction tool. Testing of the M&V methodology has successfully confirmed the magnitude of peak demand reduction achieved by voltage reduction, as well as its sustainability over a 6-hour period. It has also enabled the validation of planned demand reduction benefits associated with many of the DSDR Program implementation initiatives. Based upon testing results to-date, the estimated new peak demand reduction capability provided by DSDR, when fully operational, will be 236 MW by 2013.

Once the DSDR program is fully deployed, the Distribution Management System (DMS) will be used to determine DSDR program energy and demand savings in real time. Future DSDR program evaluation, measurement and verification (EM&V) activities will, therefore, focus on measuring the peak load reduction impact observed at PEC's Energy Control Center and Distribution Control Center, using data from the DMS. The DMS will have the capability to measure real time electrical system conditions every 15 minutes by using the various sensors and other devices installed on PEC's distribution system, perform a state estimation of the current state of devices, determine the optimum state of these devices, and execute commands using the Distribution Supervisory Control and Data Acquisition (DSCADA) system to change the state of electrical devices remotely to achieve conditions that maximize the peak load reduction capability of the distribution system and minimize the line losses. PEC is also developing a customized EM&V protocol specifically for the DSDR program to efficiently and effectively gauge its performance.

Further detail regarding the total projected smart grid impacts associated with the DSDR program is provided in the following tables, which present a breakout of total DSDR peak demand and annual energy savings by (1) the different sources of savings and (2) North Carolina retail customer class.

Program Savings by Source (at generator)

	Peak MW Demand Savings			MWh Energy Savings		
Year	**Voltage Reduction**	**Reduced Line Losses**	**All Sources**	**Voltage Reduction**	**Reduced Line Losses**	**All Sources**
2013	230	6	236	18,400	31,163	49,563
2014	234	6	240	18,730	31,618	50,348
2015	238	6	244	19,027	32,008	51,035
2016	242	7	249	19,376	32,562	51,938
2017	246	7	253	19,708	33,079	52,787
2018	250	7	257	20,024	33,574	53,598
2019	254	7	261	20,347	34,082	54,429
2020	258	7	265	20,662	34,577	55,239
2021	262	7	269	20,950	35,035	55,985
2022	266	7	273	21,253	35,515	56,768
2023	269	7	276	21,548	35,986	57,534
2024	273	7	280	21,847	36,455	58,302
2025	277	7	284	22,129	36,902	59,031
2026	281	7	288	22,455	37,417	59,872
2027	285	7	292	37,935	22,784	60,719

DSDR Peak Demand Savings – North Carolina Retail Customer Class

Year	North Carolina Peak MW Demand Savings (at generator)				
	Residential	Commercial	Industrial	Government	NC Retail
2013	92	67	37	7	202
2014	94	68	37	7	206
2015	96	70	37	7	209
2016	98	71	38	7	214
2017	100	72	38	7	217
2018	103	73	38	7	220
2019	105	74	38	7	224
2020	107	76	38	7	227
2021	109	77	38	7	231
2022	110	79	38	7	234
2023	112	80	39	7	237
2024	113	81	39	7	240
2025	115	83	39	7	244
2026	117	85	39	7	247
2027	118	86	39	7	251

DSDR Energy Savings – North Carolina Retail Customer Class

Year	North Carolina MWh Energy Savings (at generator)				
	Residential	Commercial	Industrial	Government	NC Retail
2013	17,234	13,490	10,238	1,559	42,520
2014	17,433	13,820	10,354	1,587	43,194
2015	17,724	14,065	10,399	1,594	43,783
2016	18,105	14,413	10,438	1,601	44,558
2017	18,546	14,648	10,483	1,609	45,286
2018	19,000	14,837	10,528	1,617	45,982
2019	19,414	15,083	10,573	1,624	46,695
2020	19,795	15,344	10,619	1,632	47,390
2021	20,114	15,612	10,664	1,640	48,030
2022	20,438	15,907	10,709	1,648	48,701
2023	20,748	16,201	10,754	1,656	49,358
2024	21,075	16,500	10,779	1,664	50,017
2025	21,368	16,801	10,803	1,672	50,643
2026	21,686	17,171	10,828	1,680	51,364
2027	22,004	17,546	10,853	1,688	52,091

Finally, a comparison of PEC's system load and energy forecasts both with and without the total impacts of the DSDR smart grid program is presented in the table below.

PEC System Demand and Energy Forecast – With and Without DSDR

	PEC Annual Peak MW Demand		Annual MWh Energy	
Year	**Without DSDR**	**With DSDR**	**Without DSDR**	**With DSDR**
2013	13,098	12,862	66,115,675	66,066,112
2014	13,261	13,021	66,871,664	66,821,316
2015	13,092	12,848	66,626,450	66,575,415
2016	13,268	13,019	67,571,967	67,520,029
2017	13,438	13,185	68,386,253	68,333,466
2018	13,589	13,332	69,077,950	69,024,352
2019	13,762	13,501	69,921,415	69,866,986
2020	13,941	13,676	70,624,019	70,568,780
2021	14,099	13,830	71,290,303	71,234,318
2022	14,255	13,982	72,036,892	71,980,124
2023	14,421	14,145	72,786,475	72,728,941
2024	14,580	14,300	73,616,558	73,558,256
2025	14,593	14,309	74,230,667	74,171,636
2026	14,786	14,498	75,149,769	75,089,897
2027	14,976	14,684	76,085,608	76,024,889

Discontinued Demand Side Management and Energy Efficiency Programs

Since the last biennial Resource Plan filing, PEC discontinued the following DSM/EE programs or measures.

- The Residential Home Advantage program – PEC determined that the existing program structure would no longer be cost effective due to improved building energy codes as well as more stringent Energy Star® program requirements that phase in during 2012. Therefore, PEC received NCUC approval to close the program to new applications effective March 1, 2012 and cancel the program effective March 1, 2013.
- HVAC Level-1 Tune-up, window replacement and duct testing measures – Effective Jan 31, 2012, the Home Energy Improvement program was modified to remove the HVAC Level-1 Tune-up, window replacement and duct testing measures primarily due to new information and recommendations from program evaluation, measurement and verification results.
- Premium efficiency motor incentive – The adoption of Section 313 of the Energy Independence and Security Act of 2007 regarding new electric efficiency standards for

motors now mandates the electric motor efficiency levels that PEC had been incenting through the CIG Energy Efficiency program. As a result, the program was modified to eliminate the premium efficiency motor incentive effective March 13, 2012.

- Solar Water Heating Pilot Program – This pilot program was completed on February 20, 2012 when the Final Report was submitted to the North Carolina Utility Commission.

Rejected Demand Side Management and Energy Efficiency Programs

Based on the results of PEC's Solar Water Heating Pilot Program which showed that the measure was not cost-effective, PEC will not be offering a retrofit solar thermal program for residential customers.

Current and Anticipated Consumer Education Programs

In addition to the DSM/EE programs previously listed, PEC also has the following informational and educational programs.

- Customized Home Energy Report
- On Line Account Access
- "Lower My Bill" Toolkit
- Online Energy Saving Tips
- Energy Resource Center
- CIG Account Management
- eSMART Kids Website
- Community Events

Customized Home Energy Report

During 2009, PEC launched a new educational tool available to all residential customers called the Customized Home Energy Report. This free tool educates customers about their household energy usage and how to save money by saving energy. The customer answers a questionnaire either online via www.progresscher.com or through the mail, and then receives a report that details their energy usage and educates them on specific ways to reduce their energy consumption. Additionally, the report provides specific information about energy efficiency programs and rebates offered by Progress Energy that are uniquely applicable to the customer based on data obtained within the questionnaire.

On Line Account Access

On Line Account Access provides energy analysis tools to assist customers in gaining a better understanding of their energy usage patterns and identifying opportunities to reduce energy consumption. The service allows customers to view their past 24 months of electric usage including the date the bill was mailed; number of days in the billing cycle; and daily temperature information. 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 reduce energy consumption and lower their utility bills. These range from relatively simple no-cost steps to more extensive actions involving insulation and heating and cooling equipment.

Online Energy Saving Tips

PEC has been providing tips on how to reduce home energy costs since approximately 1981. PEC's web site includes information on 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.

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 a variety of energy efficiency topics such as electric chiller operation, lighting system efficiency, compressed air systems, motor management, variable speed drives and conduct an energy audit.

CIG Account Management

All PEC commercial, industrial, and governmental customers with an electrical demand greater than 200 kW (approximately 4,800 customers) are assigned to a PEC Account Executive (AE). The AEs are available to personally assist customers in evaluating energy improvement opportunities and can bring in other internal resources to provide detailed analyses of energy system upgrades. The AEs provide their customers with a monthly electronic newsletter which includes energy efficiency topics and tips. They also offer numerous educational opportunities in group settings to provide information about PEC's new DSM and EE program offerings and to help ensure the customers are aware of the latest energy improvement and system operational techniques.

e-SMART Kids Website

PEC is offering an educational online resource for teachers and students in our service area called e-SMART Kids. The web site educates students on energy efficiency, conservation, and renewable energy and offers interactive activities in the classroom. It is available on the web at http://progressenergy.e-smartonline.net/.

SunSense Schools Program

The SunSense Schools program was a one-time program available to schools in the PEC service territory during the 2009-2010 school-year. This solar education program was the first of its kind in the Carolinas, and was designed to give middle and high school students and faculty a unique, hands-on opportunity to learn more about solar energy. Five winning schools received a two-kilowatt solar photovoltaic system installed on their campus along with internet-based tracking equipment that shows the real-time energy output. Progress Energy was proud to bring this exciting opportunity to local schools. Details on the winning schools and their solar arrays are available at www.progress-energy.com/sunsense.

Community Events

PEC representatives participated in community events across the service territory to educate customers about PEC's energy efficiency programs and rebates and to share practical energy saving tips. PEC energy experts attended events and forums to host informational tables and displays, and distributed handout materials directly encouraging customers to learn more about and sign up for approved DSM/EE energy saving programs.

Discontinued Consumer Education Programs

PEC discontinued the following educational programs since the last biennial Resource Plan filing.

- Save the Watts – Save the Watts was a branded name for PEC's effort to educate customers about energy efficiency and conservation. While the term "Save the Watts" is no longer used, PEC continues to promote all of the same efficiency and conservation information through the brand "Save Energy and Money."
- Wind for Schools – Wind for Schools was a one-time project implemented in collaboration with Mountain Valleys Resource Conservation and Development, Appalachian State University and Madison County Schools. The constructed turbine continues to produce electricity for Hot Springs Elementary School, and the school continues to use the turbine for renewable energy education purposes. However, since

this one-time project was completed in 2008, PEC chose not to list it as “current” program in this year’s IRP.

- SunSense Schools – The SunSense Schools program was a one-time program available to schools in the PEC service territory during the 2009-2010 school year. This solar education program was the first of its kind in the Carolinas and was designed to give middle and high school students and faculty a unique, hands-on opportunity to learn more about solar energy. Five winning schools received a two-kilowatt solar photovoltaic system installed on their campus along with internet-based tracking equipment that shows the real-time energy output. Progress Energy was proud to bring this exciting opportunity to local schools. Details on the winning schools and their solar arrays are available at www.progress-energy.com/sunsense.
- Newspapers in Education – Newspapers in Education is an opportunity to present energy education material as an insert in newspapers across the service territory. PEC was not approached by the media partner to offer this program in 2012.

The Value of Activating DSM Resources to Achieve Lower Fuel Costs

On October 26, 2011, the North Carolina Utilities Commission issued an "Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans" in Docket No. E-100, Sub 128, which ordered:

> *"That each IOU and EMC shall investigate the value of activating DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources. This issue shall be addressed as a specific item in their 2012 biennial IRP reports."*

PEC's investigation involved:

1. Estimating the fuel cost impacts associated with actual historical and projected future summer activations of the EnergyWise Home^{SM} (EWH) program, and
2. Developing an estimate of the cost impacts associated with program attrition (i.e., participants leaving the programs) due to the use of load control to curtail customer's electrical equipment.

Fuel Cost Impacts

PEC evaluated the fuel cost savings from DR program activations on an hourly basis for (1) actual historical events during the 2009-2011 programs years and (2) projected future events in 2012-2014. The first step of the methodology involved determining the system marginal fuel cost in $/MWh (i.e., system lambda) on an hourly basis for each day of load control using the PCI GenTrader® model. PCI GenTrader® is a detailed production cost simulation model that can be used to simulate generation system operations on an hourly basis. For the evaluation of actual historical events, the inputs to PCI GenTrader® included actual operating conditions at the time of each event, including actual weather, system load, generating unit availabilities and operating characteristics, wholesale market transactions, etc. However, during the hours affected by a DR event the model was simulated to represent what would have occurred without the DR program activation. This provided the most appropriate measure of the base case system marginal fuel cost that could be avoided by activating the DR program. During the projection period, typical peak day conditions were assumed for the purpose of estimating the base case marginal costs.

The second step consisted of determining the hourly MW impacts associated with actual and projected activation of the EWH program. This included estimating the impacts of each individual hour of load control and the hours immediately following release of the load control to account for an expected snapback effect. In this case, snapback refers to the ability of a DR program to shift load from one time period to a later period of time. Thus, while there are load reductions and fuel cost savings during the hours when a load control event is curtailing customers' electrical equipment, there can also be load and fuel cost increases during those hours immediately following a load control event as customers' electrical equipment works harder to return to normal operations. Actual event dates, start-times, stop-times and weather conditions were used to estimate the MW impacts of DR program activation during the period of historical load control events. The evaluation also accounted for program activation limits as specified by the DR program tariff. The timing of projected DR activations was assumed to coincide with the dates and times of the greatest fuel savings opportunities, i.e., during the highest system marginal costs.

Finally, total fuel cost savings were developed by multiplying system marginal fuel cost in $/MWh by the corresponding MW load reduction (or increase during periods of snapback) for each hour impacted by activation of the DR program, and summing across all event hours. This was performed for each actual and projected DR event.

The EWH program was launched in April 2009 and since that time the summer load control capability of the program has grown to just over 90 MW by the end of 2011. The total number of demand response events has also increased each year as the program has matured and garnered greater participation and load reduction capability. Table E-1 presents the actual summer demand response activation events that occurred from 2009 through 2011 as part of the EWH program, as well as PEC's estimate of the fuel savings associated with those events. During the past three summer seasons (2009-2011) load control under the EWH program was activated on thirteen days for a total of 34 hours. PEC estimates fuel cost savings from those activation events totaled $53,202, or $4,092 per event day.

Table E-1: EWH Summer Demand Response Events – Actual 2009-2011

Event Date	**Event Times (Start-Stop)**	**Duration (Minutes)**	**Maximum MW Load Reduction**	**Estimated Fuel Cost Savings ($)**
8/5/2009	14:00 - 18:00	240	3.4	$274
8/10/2009	15:00 - 18:00	180	4.4	$1,020
2009 Total Summer Fuel Savings				**$1,294**
5/6/2010	14:30 - 18:30	240	18.0	$1,234
6/24/2010	15:00 - 17:07	127	28.6	$2,131
7/7/2010	15:00 - 17:30	150	34.1	$16,366
8/11/2010	15:00 - 18:00	180	40.8	$1,897

Event Date	Event Times (Start-Stop)	Duration (Minutes)	Maximum MW Load Reduction	Estimated Fuel Cost Savings ($)
2010 Total Summer Fuel Savings				**$21,628**
5/31/2011	16:00 - 17:30	90	71.5	$3,228
6/1/2011	16:00 - 18:00	120	58.9	$6,479
7/12/2011	15:00 - 18:00	180	76.0	$4,260
7/22/2011	15:00 - 17:30	150	82.0	$4,369
7/29/2011	15:00 - 17:30	150	82.9	$4,951
8/4/2011	15:00 - 18:00	180	69.9	$4,863
8/8/2011	15:00 - 18:00	180	72.9	$2,130
2011 Total Summer Fuel Savings				**$30,280**
2009-2011 Total Summer Fuel Savings				**$53,202**

For the projection period spanning the years 2012 through 2014, PEC assumed there would be fifteen summer season load control event days each year and that those events would occur on days with the highest average system lambda. General event characteristics were standardized, such as assuming that each and every load control event would (1) have the same start and stop times of hour-ending 14:00-17:00, (2) have the same 3-hour duration and (3) achieve the maximum load reduction capability available at that time during each hour of load control. The EWH program was also assumed to continue to grow over time in terms of adding new participants each month which served to expand its maximum load reduction capability. These assumptions, along with having advance knowledge regarding the optimal dates, times and conditions for activating the DR programs, are expected to result in the projection period having the most optimistic outlook for fuel savings, especially when compared to the results obtained during the actual 2009-2011 period when activation decisions were based solely on historical information and short-term forecasts.

Since the projection period assumed the same number of events per year, the same event timing and the same event duration, Table E-2 below just presents an annual summary of EWH program activation and fuel savings forecasts. Fuel savings over the entire three projected summer seasons are $1,001,113, or $22,247 per event day when spread over all forty-five load control days.

Table E-2: EWH Summer Fuel Cost Estimates – Projected 2012-2014

Year	Number of Events	Event Times (Start-Stop)	Duration (Minutes)	Average MW Load Reduction	Estimated Fuel Cost Savings ($)
2012	15	14:00 - 17:00	180	100.0	$190,562
2013	15	14:00 - 17:00	180	117.4	$370,033
2014	15	14:00 - 17:00	180	138.3	$440,518
2012-2014 Total Summer Fuel Savings					**$1,001,113**

Program Cost Impacts

The actual cost of activating load control under the EWH program is relatively insignificant. More important are the costs associated with the effect DR program activations have on the program participants. For example, the use of load control to curtail air conditioning use during peak periods may negatively affect a customer's comfort to the point that the customer requests to be removed from the DR program. In this case, the customer has two options: (1) request to deactivate DR program service but keep the load control equipment at the residence, or (2) request removal of all PEC load control equipment installed at the residence. The latter option is clearly the most expensive since it requires traveling to and from the customer's residence and physically removing the load control equipment. In addition to the direct costs of removing equipment, there is also the cost of replacing the program participant in order to retain the same load reduction capability of the program.

To evaluate program cost impacts of program activation, PEC analyzed EWH program participation and cancellation data for fourteen summer load control events that occurred from May 2010 through July 2012. Table E-3 below provides summary information for each event. By the end of July 2012, the EWH had approximately 81,500 program participants. PEC estimates that a total of 712 participants cancelled their participation in the program due to appliance interruptions during the fourteen load control events.

Table E-3: Actual 2010-2012 PEC EWH Program Events and Participation

Event Date	Event Times (Start-Stop)	Duration (Minutes)	Avg. System Temperature (Degrees F)	Total Program Participants	Program Cancellations Due to Event	Program Cancellation Rate (%)
5/6/2010	14:30 - 18:30	240	90	20,555	11	0.0535%
6/24/2010	15:00 - 17:07	127	96	26,400	14	0.0530%
7/7/2010	15:00 - 17:30	150	100	27,662	21	0.0759%
8/11/2010	15:00 - 18:00	180	97	31,597	29	0.0918%
5/31/2011	16:00 - 17:30	90	98	57,662	14	0.0243%
6/1/2011	16:00 - 18:00	120	93	57,732	32	0.0554%
7/12/2011	15:00 - 18:00	180	98	61,292	69	0.1126%
7/22/2011	15:00 - 17:30	150	100	62,230	78	0.1253%
7/29/2011	15:00 - 17:30	150	100	62,829	80	0.1273%
8/4/2011	15:00 - 18:00	180	95	63,244	79	0.1249%
8/8/2011	15:00 - 18:00	180	96	63,366	70	0.1105%
5/2/2012	15:30 - 17:30	120	90	81,260	41	0.0505%
7/6/2012	15:00 - 17:00	120	97	81,217	64	0.0788%
7/26/2012	15:00 - 18:00	180	98	81,487	110	0.1350%
2010-2012 Total EWH Cancellations					**712**	
Average Cancellation Rate per-event						**0.0871%**

Of those 712 customer cancellations, roughly 60% simply requested deactivation of the load control service (without equipment removal) and about 40% requested the equipment be removed. PEC then performed a cost evaluation of the various cancellation options and determined that the average incremental program cost of deactivating and replacing an EWH program participant was $205. Thus, the total program cost associated with participants leaving the EWH program due to actual DR program activations during the June 2010 through July 2012 time frame is $145,960 (i.e., 712 participant cancellations multiplied by the $205 average cost-per-customer). PEC also estimated the total program costs for the same 2009-2011 actual period that was used to develop the estimates of fuel cost savings by removing the customer cancellations that occurred during the three 2012 events and assuming no cancellations for the two 2009 events when the program was just starting up. The resulting 2009-2011 program cost estimate of $101,885 provides a more direct apples-to-apples basis for comparison with the actual period fuel cost savings results.

PEC also developed program cost estimates during the same 2012-2014 projection period used to determine projected fuel savings by applying the average cancellation rate-per-event of 0.0871%

to the number of program participants at the time of all projected EWH load control events. The total program cost for removing/replacing participants lost due to EWH program activations during the entire 2012-2014 projection period is $793,760. There is a risk, however, that the cancellation rate in the projection period may actually be higher than the average historical value due to the much higher number of program activation events assumed in the future, where fourteen events are expected each year which is more than double the number of events in 2011. PEC, therefore, also evaluated the projected program cost to remove/replace participants assuming a slightly higher 0.1% cancellation rate. This resulted in a total 2012-2014 program cost of $910,200 to remove/replace EWH participants.

Conclusion

PEC's EWH program was originally designed as an alternative to building supply-side resources and, as such, to provide a different type of capacity resource that could be dispatched as needed to support overall system reliability during times of peak load and capacity constraints. Consequently, it is primarily the capacity value of the DR program that makes it such a cost-effective resource option. While economic dispatch of the program for the purpose of reducing fuel costs is a reasonable application of the program, it should be a secondary objective to the main goal of ensuring sufficient capacity to meet system reliability needs. Dispatching DR resources purely for economics poses the risk of overuse, such as using it for three or more consecutive days when a hot, dry spell settles into the area and causes peak load conditions that require the use of expensive oil CT generation. However, these peak usage periods are also the times when customers most need cooling from their air conditioning equipment, so excessive curtailments of that end-use can cause sufficient customer discomfort and dissatisfaction that they decide to leave the program.

When considering how EWH program activations affect both the potential for fuel cost savings and program costs incurred as a result of customer cancellations, the actual net savings was a negative $48,683 during the 2009-2011 actual period. Even with the use of perfect information and substantially more activations during the 2012-2014 projection period, estimated net savings ranged only between a positive $207,353 and a positive $90,913 over the entire three year time frame. Thus, activating the EWH program for economic purposes appears to provide little or no additional value beyond the substantial amount of capacity value provided by the program, especially given the uncertainty associated with customer acceptance and retention posing a risk to actually realizing net benefits. Over the past four years a weak economy, flat load growth and increasing reserve margins have not been conducive for reliability-based DR program activations. However, as economic conditions improve and load growth increases in the future, the likelihood of needing to use the program more often to support system reliability will also increase, thereby reducing the number of opportunities to use the program for economics.

This doesn't necessarily preclude using the EWH program for economic purposes. PEC just believes that the economic dispatch of DR requires a balanced operational strategy – one that balances the need to maintain a stable long-term capacity resource with the desire to achieve near-term production cost savings. Program activations, whether for economics or reliability, must avoid overuse, minimize customer discomfort associated with load control and ultimately keep customers from leaving the program.

Progress Energy Carolinas

Integrated Resource Plan

Appendix F
Environmental Regulations and Climate Change

November 2012

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 has significantly reduced SO_2 and NOx emissions from its NC coal-fired units. By 2013, PEC projects SO_2 emissions will be reduced by approximately 93% and NOx emissions will be reduced by approximately 88% from their year 2000 levels. Further reduction is expected in 2014 by retiring the Lee and Sutton coal units and replace them by state-of-the-art gas-fired combined cycle units.

Cross-State Air Pollution Rule (CSAPR)

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 emissions in two phases beginning in 2009 and 2015, respectively, and reduce SO_2 in two phases beginning in 2010 and 2015, respectively. States were required to adopt rules implementing the CAIR. The EPA approved both the North and South Carolina CAIR rules 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 ruled that the CAIR would remain in effect until EPA revised or replaced it with a regulation that complies with the Court's decision. On July 7, 2011, the EPA issued the final Cross-State Air Pollution Rule (CSAPR), which is the regulatory program that replaces the CAIR. The CSAPR contains limited intrastate emissions trading programs for NOx and SO_2 emissions and significantly more stringent overall emissions targets. PEC is reviewing the impacts of the CSAPR on the generating fleet, and additional reductions may be needed at some of PEC's units. On December 30, 2011, the D.C. Court of

Appeals stayed the CSAPR, leaving the CAIR in effect until litigation of the CSAPR is resolved. On August 21, 2012 the D.C. Circuit issued its judgment and opinion in the CSAPR litigation, vacating CSAPR and the CSAPR federal implementation plans (FIPs) and directing EPA to continue administering the Clean Air Interstate Rule (CAIR) pending completion of a remand rulemaking to replace CSAPR with a valid 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 fulfills the BART requirements.

Mercury Regulation

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. As a result, the EPA subsequently announced that it will develop a MACT standard consistent with the agency's original listing determination. The United States District Court for the District of Columbia has issued an order requiring the EPA to issue a final MACT standard for power plants by November 16, 2011. On February 16, 2012 EPA published the final MACT rule to regulate mercury and other hazardous air pollutants from coal- and oil-fired electric utility steam generating units (also known as the Mercury and Air Toxics Standards or MATS rule). The rule establishes strict emission standards for mercury, hydrogen chloride (HCl, as a surrogate for acid gases), and particulate matter (as a surrogate for non-mercury metals). The MATS rule may require additional emission controls at PEC's coal-fired facilities. Although the federal CAMR was vacated, state-specific mercury control requirements 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. As a result of legal action regarding the revised standard, in September 2009 the EPA announced that it is reconsidering the level of the ozone NAAQS. On January 7, 2010, the EPA announced a proposed revision to the primary ozone NAAQS. However, in September 2011, the EPA withdrew the proposed revision, and it is now in the process of implementing the 2008 NAAQS. The currently are no ozone nonattainment areas in PEC's service territory.

On October 15, 2008, the EPA revised the NAAQS for lead to 0.15 micrograms per cubic meter on a rolling 3-month average basis. The revision is not expected to have a material impact on PEC's operations.

On January 25, 2010, the EPA announced a revision to the primary NAAQS for NOx. Since 1971, when the first NAAQS were promulgated, the standard for NOx has been an annual average. The EPA has retained the annual standard and added a new 1-hour NAAQS. In conjunction with proposing changes to the standard, the EPA is also requiring an increase in the coverage of the monitoring network, particularly near roadways where the highest concentrations are expected to occur due to traffic emissions. Currently, there are no monitors reporting violation of the new standard in PEC's service territories, but the expanded monitoring network will provide additional data, which could result in additional nonattainment areas.

On June 22, 2010, the EPA published a final new 1-hour NAAQS for SO_2, which sets the limit at 75 parts per billion. The primary NAAQS on a 24-hour average basis and annual average will be eliminated under the new rule. The new 1-hour standard is a significant increase in the stringency of the standard and increases the risk of nonattainment, especially near uncontrolled coal-fired facilities. In addition, for the first time the EPA plans to use air quality modeling in addition to monitor data in determining whether areas are attaining the new standard, which is likely to expand the number of nonattainment areas. EPA is scheduled to designate nonattainment areas by June 3, 2013. Should additional nonattainment areas be designated in PEC's service territories, PEC may be required to install additional emission controls at some of its facilities.

Global Climate Change

PEC has identified principles that should be incorporated into any global climate change policy. In addition to reports issued in 2006 and 2008, PEC issued updated reports on global climate change in 2010, 2011, and 2012 as part of its annual Corporate Responsibility Report, which further evaluates this dynamic issue. While PEC participates in the development of a national climate change policy framework, it will continue to actively engage others in its region to develop consensus-based solutions, as was done with the NC Clean Smokestacks Act. In North Carolina, PEC participated in the Legislative Commission on Global Climate Change, which developed recommendations on how the state should address the issue. In South Carolina, PEC participated in 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 (CAA) to regulate CO_2 emissions from new automobiles. On December 15, 2009, the EPA announced that six Greenhouse Gases (GHGs) (CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride) pose a threat to public health and welfare under the CAA. A number of parties filed petitions for review of this finding in the D.C. Court of Appeals, and on June 25, 2012 the court ruled against the petitioners, leaving the EPA's finding and the associated regulations in effect.

On April 1, 2010, the EPA and the National Highway Transportation Safety Administration jointly announced the first regulation of GHG emissions from new vehicles. The EPA is regulating mobile source GHG emissions under Section 202 of the CAA, which, according to the EPA, also results in stationary sources, such as coal-fired power plants, being subject to regulation of GHG emissions under the CAA. On March 29, 2010, the EPA issued an interpretation that stationary source GHG emissions will be subject to regulation under the CAA beginning in January 2011. On May 13, 2010, the EPA issued the final "tailoring rule", which establishes the thresholds for applicability of Prevention of Significant Deterioration (PSD) permitting requirements for GHG emissions from stationary sources such as power plants and manufacturing facilities. The rule establishes the GHG permitting threshold at 75,000 tons per year, and the permitting requirements for GHG emissions from stationary sources began January 2, 2011. These developments may require PEC to address GHG emissions in air quality permits.

In December 2010, the EPA announced a settlement with environmental groups and several states that established a schedule by which EPA would promulgate New Source Performance Standards (NSPS) for GHG emissions from new and modified electric utility units. On April 13, 2012, the EPA proposed GHG NSPS that would adopt a single, fuel-neutral CO_2 emission standard for new fossil fuel-fired units that is based on the emission rate from a natural gas-fired, combined-cycle facility. The EPA is not expected to finalize the NSPS until after the 2012 election.

Although Congressional activity on climate change has decreased, Congress may consider passing GHG emissions legislation in the future. The full impact of such legislation, if enacted, and additional regulation resulting from other federal GHG initiatives cannot be determined at this time; however, PEC anticipates that it could result in significant cost increases over time.

Coal Combustion Residuals (CCR) Proposed Regulations

On June 21, 2010, EPA proposed two approaches for regulating disposal of Coal Combustion Residuals (CCR) under the Resource Conservation and Recovery Act (RCRA) to address the risks from the disposal of CCRs generated from the combustion of coal at electric utilities and independent power producers. The Agency is considering primarily two options in this proposal and, thus, is proposing two alternative regulations.

1. Subtitle C approach:

   Under the first proposal, EPA would reverse its August 1993 and May 2000 Bevill Regulatory Determinations regarding coal combustion residuals (CCRs) and list these residuals as special wastes subject to regulation under subtitle C of RCRA (hazardous wastes), when they are destined for disposal in landfills or surface impoundments.

2. Subtitle D approach:

   Under the second proposal, EPA would leave the Bevill determination in place and regulate disposal of such materials under subtitle D of RCRA (non-hazardous wastes) by issuing national minimum criteria.

Engineering requirements (e.g., liners, groundwater monitoring) of the two options are very similar; differences are primarily in enforcement and implementation. Exemption from the hazardous waste regulations under RCRA, Section 3001(b)(3)(A), would remain in place for beneficial uses of CCRs. Mine filling is not covered by the proposal. Under both alternatives, EPA is proposing to establish dam safety requirements to address the structural integrity of surface impoundments to prevent catastrophic releases, as well as imposing new federal requirements for siting of disposal facilities and possible groundwater corrective measures. Under the proposed hazardous waste rules landfill siting, material handling, and transportation costs would be significantly greater. Regulation as a hazardous waste will likely impose a stigma that would impair the market for beneficial uses. This would also increase the quantity and cost of disposal (landfill) and ash pond closure. There is a recent lawsuit by environmental groups hoping to get a settlement for a final rule date as early as possible. However, there is no statutory or judicial deadline for a final rule.

Clean Water Act (CWA), Section 316 (b) Proposed Regulations for Cooling Water Intake Structures at Existing Facilities

In accordance with a court-approved settlement agreement, EPA released its proposed regulations addressing cooling water intake structures at existing power generating facilities on March 28, 2011. The proposal is applicable to facilities that are designed to withdraw more than 2 million gallons per day (MGD) of water from waters of the U.S. and use at least 25 percent of the water withdrawn for cooling purposes. Existing facilities that currently use closed-cycle cooling and withdraw more than 2 MGD would be subject to the rule but would have streamlined information submission requirements.

The rule is intended to minimize environmental impact resulting from the mortality or injury to aquatic organisms that would otherwise be entrained into cooling water systems or impinged against screens or other devices at the entrance of cooling water intake structures.

Performance standards for impingement mortality. An existing facility would comply with either of the following standards:

- Impingement mortality must not exceed 12% as an annual average or 31% as a monthly average. This standard is based on the use of modified traveling screens with a fish handling and return system.
- The maximum cooling water intake velocity shall not exceed 0.5 feet per second.

Performance standards for entrainment mortality. Standards for entrainment mortality would be determined on a case-by-case basis. Facilities that withdrawal more than 125 MGD must prepare the following:

- entrainment characterization study;
- comprehensive technical feasibility and cost evaluation study that, as a minimum, must evaluate the technical feasibility of closed-cycle, recirculation systems (cooling towers) and fine mesh screens with a mesh size of 2 mm or smaller,
- benefits valuation study that evaluates the magnitude of water quality benefits, both monetized and non-monetized, of the candidate entrainment mortality reduction technologies and operational measures; and
- non-water quality and other environmental impacts study that addresses onsite changes in energy consumption, impacts to grid reliability, estimates of air pollutant emissions changes, changes in noise, etc.

State permitting agencies would be required to establish case-by-case entrainment mortality controls. These entrainment mortality controls would reflect a determination of the maximum reduction in entrainment mortality warranted after consideration of nine factors specified in the rule including numbers and types of organisms entrained, impacts to the source water body, land availability, impacts to reliability of energy delivery, impacts on water consumption, remaining useful plant life, etc.

The rule attempts to clarify the definitions of “new” versus “existing.” EPA proposes to establish January 17, 2002 as the date for distinguishing existing facilities from new facilities. An upgraded unit, a replacement unit or repowered unit, as distinct from constructing an additional unit, would not be treated as a new unit. New units using existing intake structures must reduce actual intake flow to a level commensurate with a closed-cycle recirculation cooling system.

The final regulations are due in June 2013 and become effective 60 days after publication in the *Federal Register*. In accordance with the proposed rule, facilities must comply with the impingement mortality standard as soon as possible and, in all cases, within eight years of the effective date of the rule. Compliance with the entrainment mortality standard may extend beyond eight years with approval by State NPDES permitting agencies. State NPDES permitting agencies may also impose a shorter timeline for compliance with either standard. Significant portions of the permit application requirements, including a proposed impingement mortality reduction plan, would be due within six months of the effective date of the regulations. Other application requirements addressing entrainment have phased-in due dates extending out as long as five years.

Progress Energy Carolinas

Integrated Resource Plan

Appendix G
Transmission and NC Rule R8-62

November 2012

This appendix lists the planned transmission line and substation additions, and includes a discussion of the adequacy of PEC's transmission system. The transmission additions are sub-divided into three (3) tables. Table 1 lists the transmission line projects that PEC has agreed to construct as part of its merger commitments. Table 2 and Table 3 list the line and substation projects that were planned pre-merger. This appendix also provides information pursuant to the North Carolina Utilities Commission Rule R8-62.

Table 1: PEC Merger Mitigation Line Additions

	LOCATION				
YEAR	FROM	TO	CAPACITY MVA	VOLTAGE KV	COMMENTS
2014	Lilesville	Rockingham	793	230	New
2014	Greenville	Kinston Dupont	1195	230	New*
2014	Kinston Dupont	Wommack	1195	230	Uprate
2014	Wake	Carson(DVP)	3442	500	Uprate
2014	Durham	E. Durham(Duke)	1077	230	Uprate
2014	Roxboro S.E.P	E. Danville(AEP) South	960	230	Modification

*The Greenville-Kinston Dupont 230 kV line was planned for 2017 pre-merger and is now planned for 2014

Table 2: PEC Transmission Line Additions (Non merger related)

	LOCATION				
YEAR	FROM	TO	CAPACITY MVA	VOLTAGE KV	COMMENTS
2014	Harris	RTP Switching Sta.	1195	230	New
2018	Richmond	Raeford	1195	230	Relocate, new
2018	Ft. Bragg Woodruff St.	Raeford	1195	230	Relocate, new

Table 3: PEC Substation Additions (Non merger related)

YEAR	SUBSTATION NAME	COUNTY	STATE	VOLTAGE (KV)	MVA	COMMENTS
2012	West End	Moore	NC	230/115	600	Uprate
	Lee Sub	Wayne	NC	230/115	N/A	Modification
	Folkstone	Onslow	NC	230/115	200	New
2013	Jacksonville	Onslow	NC	230	300	New
	Sumter	Sumter	SC	230	N/A	Modification
	Selma	Johnston	NC	230/115	400	Uprate
	Sutton Plant	Brunswick	NC	230/115	N/A	Modification
2014	Fayetteville	Cumberland	NC	230/115	600	Uprate
2016	Falls	Wake	NC	230/115	600	Uprate
2018	Raeford	Hoke	NC	230/115	600	Uprate

Rule R8-62 Requirements

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.

Please refer to the Company's FERC Form No. 1 filed with NCUC in April, 2012.

(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.

Lilesville – Rockingham 230 kV Line

Project Description: Construct approximately 14 miles of new 230 kV transmission line from the Lilesville 230 kV Substation in Anson County to the Rockingham 230 kV Substation in Richmond County.

a. Commission docket number; NCUC Docket No. E2, Sub 922
b. County location of end point(s); Anson and Richmond Counties
c. Approximate length; 14 Miles
d. Typical right-of-way width for proposed type of line; 100 Feet
e. Typical tower height for proposed type of line; 80 - 120 Feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 793 MVA
i. Date construction started; July 2012
j. Estimated in-service date; June 2014

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. Pursuant to N.C.G.S. 62-101, no Certificate of Environmental Compatibility and Public Convenience and Necessity is required because the rights-of-way for this line were acquired prior to March 6, 1989.

a. N/A – ROW acquired prior to March 6, 1989
b. County location of end point(s); Lenoir and Pitt Counties
c. Approximate length; 25.3 Miles
d. Typical right-of-way width for proposed type of line; 100 Feet
e. Typical tower height for proposed type of line; 80 - 120 Feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 1195 MVA
i. Date construction started; July 2012
j. Estimated in-service date; June 2014

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 in service and built on self-supporting single poles. The remaining construction is planned to be placed in service 6/2014 and consists 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.

a. Commission docket number; NCUC Docket No. E2, Sub 914
b. County location of end point(s); Wake
c. Approximate length; 22 miles
d. Range of right-of-way width; 70 feet
e. Range of tower heights; 100 feet
f. Number of circuits; 1
g. Operating voltage; 230 kV
h. Design capacity; 1195 MVA
i. Date construction started; 2010- RTP-Amberly 230 kV Section in-service, Amberly-Green Level Section is Cleared, 2011- Construction of line resumed.
j. Projected in-service date; June 2014

(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.

Richmond – Raeford 230 kV Line loop-in

Project Description: Loop-In the existing 230 kV transmission line from the Richmond 230 kV Substation in Richmond County to the Ft. Bragg Woodruff St 230 kV Substation in Cumberland County at Raeford 230 kV Substation in Hoke County.

a. County location of end point(s); Hoke County
b. Approximate length; 5 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; 1195 MVA
h. Estimated date for starting construction; March 2015
i. Estimated in-service date; June 2018

Ft. Bragg Woodruff St – Raeford 230 kV Line loop-in

Project Description: Loop-In the existing 230 kV transmission line from the Richmond 230 kV Substation in Richmond County to the Ft. Bragg Woodruff St 230 kV Substation in Cumberland County at Raeford 230 kV Substation in Hoke County.

a. County location of end point(s); Hoke County
b. Approximate length; 5 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; 1195 MVA
h. Estimated date for starting construction; March 2015
i. Estimated in-service date; June 2018

Discussion of the adequacy of the PEC transmission system

The PEC transmission system consists of approximately 6,200 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 Energy Carolinas, 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 Corporation (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 service area is within the SERC Reliability Corporation (SERC) Region. SERC annually checks for compliance and conducts detailed audits of standards compliance every three years. The most recent PEC audit, in the spring of 2011, 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 SERC Intra-regional Long-Term Study Group (LTSG) and the SERC Intra-regional Near-Term Study Group (NTSG). For inter-regional studies PEC actively participates on the Eastern Interconnection Reliability Assessment Group (ERAG).

The transmission system is planned to ensure that no equipment overloads and adequate voltage is maintained to provide reliable service. 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 called the NCTPC (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. The NCTPC has a data exchange agreement with PJM to share planning data.

PEC also participates in the SIRPP (Southeastern Inter-regional Participation Process) and the EIPC (Eastern Interconnection Planning Collaborative) inter-regional efforts.

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 Carolinas

Integrated Resource Plan

Appendix H
Short Term Action Plan

November 2012

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. Miscellaneous unit uprates (see 2012 IRP)
2. Wayne County CC – A Certificate of Public Convenience and Necessity was approved on October 22, 2009. The plant is on schedule for a January 1, 2013 in-service date.
3. Sutton CC – A Certificate of Public Convenience and Necessity was approved on June 9, 2010. The plant is on schedule for a December 1, 2013 in-service date.

Near Term, Known Resource Retirements

1. Lee Coal Units 1-3 – 09/2012
2. Cape Fear Coal Units 5 & 6 – 10/2012
3. Sutton Coal Units 1-3 – 12/2013
4. Robinson 1 Coal Unit 1 – 10/2012
5. Lee CT Units 1-4 – 10/2012
6. Morehead CT Unit 1 – 10/2012
7. Cape Fear CT Unit 2B – 10/2012

New DSM and EE

PEC's DSM/EE portfolio currently consists of the following programs as approved by the North Carolina Utilities Commission and/or the Public Service Commission of South Carolina:

1. Residential Home Energy Improvement Program
2. Residential Home Advantage Program (Closed to New Participants)
3. Residential New Construction Program
4. Neighborhood Energy Saver (Low-Income) Program
5. Residential Lighting Program
6. Appliance Recycling Program
7. Residential Energy Efficient Benchmarking Program
8. Commercial, Industrial, and Governmental (CIG) Energy Efficiency Program
9. Small Business Energy Saver Program
10. Residential EnergyWise℠ Program
11. Commercial, Industrial, and Governmental (CIG) Demand Response Program
12. Distribution System Demand Response (DSDR) Program
13. Residential Prepay Pilot Program

PEC is continually seeking to enhance its DSM/EE portfolio by: (1) adding new or expanding existing programs to include additional measures, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results, and (3), other

EE research & development pilots. The following projects represent program enhancements that are currently underway and expected to be implemented within the biennium for which this IRP is filed.

- Residential Lighting Program -- PEC is planning to broaden the availability of measures provided under its Residential Lighting Program to include other efficient lighting technologies, such as LEDs, 2X incandescent and CFL fixtures.
- Neighborhood Energy Saver Program -- PEC is evaluating various options for expanding its existing low-income energy efficiency program including but not limited to consideration for additional measures, broader reaching efforts, and additional delivery/implementation channels. PEC is currently achieving 85% penetration levels in targeted neighborhoods within its Neighborhood Energy Saver program and desires to further build upon this success with additional energy savings enhancements that are in the continued best interest of the company and its customers.
- Residential New Construction Program -- PEC has received approval in South Carolina for this replacement to the now closed Residential Home Advantage program and has submitted the program for approval in North Carolina.
- Small Business Energy Saver Program -- PEC has received approval for this direct-install EE program in South Carolina and has submitted the program for approval in North Carolina.

Alternative Supply Resources (Incremental Renewables)

The 2012 Integrated Resource Plan includes the following near term assumptions for additional renewable resources:

1. 54 MW of poultry waste generation online by 2016
2. Approximately 6.4 MW of biomass generation online in 2013

Negotiations for these and other projects are ongoing.

For more detail on all of these ongoing activities, please see PEC’s 2012 IRP.