PUBLIC VERSION—CONFIDENTIAL INFORMATION REDACTED

STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

DOCKET NO. 2011-10-E

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In the Matter of:	)	
	)	COMMENTS ON DUKE ENERGY
Duke Energy Carolinas, LLC's	)	CAROLINAS, LLC'S 2011
Integrated Resource Plan (IRP)	)	INTEGRATED RESOURCE PLAN
	)	
	)	

Pursuant to South Carolina Public Service Commission ("Commission") Order No. 2010-124 on least cost planning for electric utilities, the Southern Alliance for Clean Energy ("SACE"), South Carolina Coastal Conservation League ("CCL") and Upstate Forever (collectively, "Petitioners"), through counsel, hereby submit comments in the above-captioned docket concerning Duke Energy Carolinas, LLC's ("DEC" or "the Company") 2011 Integrated Resource Plan ("IRP"), filed with the Commission on September 1, 2011.[1]

I. SUMMARY OF CONCLUSIONS.

Based on a review of DEC's 2011 IRP, Petitioners present the following conclusions:

- Regardless of the supply-side resource option, portfolios including DEC's "High DSM" case represent the lowest cost, lowest risk scenario options in the IRP.

- DEC has made progress on efficiency, but did not adequately consider this valuable resource in its evaluation of resource options. In contrast to DEC's higher-than-expected performance in 2010, DEC has reduced the projected long-term impact of energy efficiency in its IRP by 11% without a clear explanation.

- DEC's IRP overstates the Company's need for new generating capacity.

- DEC has prudently decided to retire its existing unscrubbed coal units, but the IRP fails address the economics of the continued operation of scrubbed coal units.

[1]On October 26, 2011, the Commission granted Petitioners' motion for leave to file comments out of time by October 31, 2011. *See* Order No. 2011-789. These comments were prepared with the assistance of John D. Wilson, Director of Research for SACE.

- Duke does not incorporate realistic assumptions about the cost of new nuclear generation in its IRP.

- Modeling of economic impacts should be included to inform the evaluation of resource portfolios.

II. LEGAL FRAMEWORK FOR INTEGRATED RESOURCE PLANNING.

South Carolina electric utilities must prepare integrated resource plans, which may be patterned after the Commission's integrated resource planning process. S.C. Code Ann. § 58-37-40 (2010). Electric utilities regulated by the Commission must submit their IRPs to the State Energy Office on a triennial basis and must update the plans on an annual basis. *Id.* Compliance with the Commission's IRP requirements constitutes compliance with statutory IRP requirements. *Id.*

An IRP must contain the following information:

1. The demand and energy forecast for at least a 15-year period.

2. The supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options.

3. A brief description and summary of cost-benefit analysis, if available, of each option considered, including those not selected.

4. The supplier's and producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and a description of the external, environmental and economic consequences of the plan to the extent practicable.

Commission Order No. 1998-502; S.C. Code Ann. § 58-37-10 (2010). Moreover, the Commission can require additional information in IRP filings and provide it to interested parties if necessary to facilitate the parties' understanding of the above-required information. Commission Order No. 1998-502.

DEC is regulated by the Commission, and therefore is subject to the Commission's integrated resource planning process. S.C. Code Ann. § 58-3-140 (2010). The Commission developed its integrated resource planning process for electric utilities in a least cost planning docket initiated in 1987. *See* Commission Docket No. 1987-223-E. Least cost planning, as the Commission has defined it, "refers to efforts by utilities and regulators to ensure that the lowest cost options to the ratepayers and utilities are integrated into the designing [of] resource plans for the provision of energy services to customers." Order No. 1987-569.

In 1991, the Commission adopted an integrated resource planning process designed to develop a plan that "results in the minimization of the long run total costs of the utility's overall system and produces the least cost to the consumer consistent with the availability of an adequate and reliable supply of electricity while maintaining system flexibility and considering environmental impacts." Appendix A at 1, Order 1991-1002. In 1998, the Commission modified the IRP process to its present form, requiring utilities to file IRPs that contain the four substantive requirements outlined above. *See* Order No. 1998-502.[2] The Commission established procedural requirements for IRP filings in 2010, pursuant to which DEC must file its IRP by September 1 of each year; interested persons are allowed 30 days to file written comments; and Commission Staff must schedule an allowable ex parte briefing within 60 days of the filing. Order No. 2010-124.

For the reasons detailed below, DEC's IRP does not reflect a long-term plan to meet its customers' energy needs in an economic and reliable manner. DEC does not adequately integrate demand-side options, namely energy efficiency, into its long-term resource plan, despite the quantifiable benefits of doing so, and does not evaluate the economic impact of continuing to operate some of its coal units in light of pending and imminent environmental regulations and significant environmental compliance costs. Moreover, DEC does not provide realistic assumptions with respect to new nuclear generation, which could impact the cost and reliability of energy service.

III. DEC SHOULD HAVE PRIORITIZED ITS "HIGH DSM" ALTERNATIVE.

DEC conducts a quantitative analysis of resource options to meet forecasted energy and capacity needs. IRP at 95. DEC assesses its resource needs, identifies and screens resource options, develops and analyzes resource portfolios and then selects a preferred portfolio. *Id.* at 95-107. In its 2011 analysis, DEC modeled several resource portfolios in both base case and sensitivity analyses. IRP at 100. Some of these portfolios used a "High Energy Efficiency" or "High DSM" case sensitivity, which represents increased energy savings from DEC's energy efficiency programs as compared to the base case for DSM. *Id.* at 101. Specifically, the High DSM case is a "sensitivity [that] includes the full target impacts of the Company's save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales every year after that."[3] *Id.* This approach is similar to the one described in DEC's 2010 IRP, in which the Company evaluated an almost-identical "High DSM" scenario in its sensitivity analyses. 2010 IRP at 88.

Based on an analysis of the portfolios presented in DEC's 2010 IRP, Petitioners conclude that portfolios incorporating DEC's High DSM case cost less, have lower risk,

[2]The IRP process was modified in 1993, but the overall framework of the planning process remained intact. Order No. 1993-845. In 1998, however, Appendix A to Order 1991-1002, which detailed the Commission's IRP planning process, was replaced in its entirety by the 1998 Order Modifying Reporting Requirements, Order No. 1998-502, which outline the IRP requirements currently in place.

[3]It is unclear whether DEC has capped the energy efficiency resource by estimates included in the 2007 market potential study. This topic is discussed further in Attachment 1, "Review of Utility Evaluation of Energy Efficiency Resources in the Carolinas (October 2011)."

and appear to result in lower average electricity rates than does any portfolio using base case DSM assumptions. Despite these benefits, however, DEC did not select a portfolio with the "High DSM" case, and as a result, DEC's presented plan does not yield the lowest-cost resource mix.

A. Duke's High DSM case results in lower cost to customers.

DEC tested the following three resource scenarios under base assumptions and sensitivities for fuel costs, load/energy efficiency, CO_2 prices and nuclear capital costs: 1) no new nuclear capacity (the CT/CC portfolio); 2) full ownership of new nuclear capacity (2 unit portfolios); and 3) regional co-ownership of new nuclear capacity. *Id.* at 100-03. DEC selected a 2 Nuclear Unit portfolio as its "optimal plan" based on the relatively small cost advantage that nuclear portfolios have over non-nuclear portfolios in its analysis. *Id.* at104.

DEC does not include the High DSM portfolio in its "optimal plan" even though the cost savings associated with the High DSM case are greater than the cost difference illustrated in the nuclear vs. non-nuclear analysis. Based on DEC's quantitative analysis for its 2010 IRP,[4] ***all portfolios with High DSM cost at least*** [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] ***than the "optimal plan" over the 50-year analysis time frame***.[5] This means that a truly "least cost" resource plan would include the High DSM portfolio, and therefore, Duke should have included the High DSM portfolio in its preferred plan.

B. DEC's High DSM case would expose customers to a lower risk of cost increases.

DEC developed various resource portfolio options "to assess the impact of various risk factors on the costs to serve customers," *id.* at 98, and analyzed the risk associated with the various portfolios by comparing them across a range of sensitivities.

Because fuel and environmental costs are passed through to customers, DEC's customers bear a substantial price risk if fuel prices and environmental costs, such as a price on CO_2 emissions, are higher than anticipated. There is no standard metric to measure customer price risk, but it is possible to compare the risk associated with different levels of investment in competing resources.

DEC's quantitative analysis shows that the High DSM strategy would reduce system risk due to fuel price variability more effectively than would a strategy that favors power plant construction. Under conditions of high fuel and high CO_2 prices, selecting the High DSM strategy results in about [BEGIN CONFIDENTIAL [redacted] END

[4]Petitioners do not have the 2011 IRP data to conduct an analysis similar to the 2010 IRP analysis, but DEC does not describe any substantial changes in its IRP assumptions that would likely result in a different conclusion.

[5]For a detailed cost comparison of DEC's "High DSM" and "Base DSM" portfolios, *see* Attachment 2.

CONFIDENTIAL] in price spike mitigation.[6] This is true regardless of the type or level of supply-side investment under consideration.

Another source of risk is construction (or capital) cost increases. Both nuclear and DSM have relatively low annual expenses (fuel and operating costs) as compared to fossil fuel generation, and the capital cost risk constitutes the bulk of the cost risk for these resources. DEC did not perform capital cost sensitivity analysis for the High DSM resource, but it is likely that capital cost risk associated with DSM is significantly lower than that associated with nuclear power. Using a paired-comparison analysis, the replacement of one nuclear unit with the High DSM strategy can save an estimated [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] in capital costs.[7] Since the capacity provided by both the nuclear unit and the High DSM case are similar, the base case assumption for DSM costs is about [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] percent less than the equivalent in nuclear capacity.[8]

Based on the [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] percent discount and the capacity cost comparison, it appears that the High DSM resource has a present value cost on the order of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL]. Even if this cost were to double or triple (a capital cost sensitivity of 200-300 percent), the "High DSM" resource investment would still cost less and be more effective than nuclear plants at mitigating the impact of fuel price variability, higher CO_2 prices, and other variable cost risks.

Another reason that DSM has less risk than nuclear power is that the investment occurs in smaller increments. It is relatively straightforward—and inexpensive—for an energy efficiency program to be cancelled or modified as compared to a large nuclear power plant.

The major risk factor of the "High DSM" case is the impact of market or regulatory barriers to development of the efficiency resource. For example, the ability of industrial customers to "opt-out" of utility energy efficiency and demand response programs, combined with a lack of external accountability for self-directed industrial energy efficiency programs, may impede the development of the efficiency resource. On the other hand, the numerous obstacles to the timely, safe and cost-effective development of nuclear power units are also well documented, as discussed later in these comments. DEC does not explain why obstacles to developing aggressive demand-side resources are

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[6]This price spike mitigation is in addition to the cost advantage demonstrated for High DSM resources in the base case.

[7]The PVRR of the capital cost is also affected by the slight decrease in natural gas (CT) units and the different construction schedule for natural gas units. The direction of the PVRR impact could not be inferred from available data due to the significantly different construction schedules. However, because the capital cost of nuclear plants is at least 4 times greater than that of gas units, it likely would be a relatively small adjustment.

[8]*See* Attachment 2, Cost Comparison of Duke's "High DSM" and "Base DSM" Portfolios.

greater than obstacles to the development of supply-side resources, such as nuclear power, and the available evidence indicates that the obstacles for demand-side resources are in fact smaller.

C. The qualitative advantages cited for the regional nuclear approach also favor the High DSM alternative.

In its discussion of a regional nuclear approach, DEC cites load growth, financial impact, and regulatory uncertainty as reasons that favor a regional approach over a single utility development. *Id* at 104. Each of these factors also favors the High DSM alternative over the base case.

First, DEC states that under regional nuclear approach "[s]maller blocks of base load generation brought on-line over a period of years would more closely match projected load growth." *Id.* Because the High DSM alternative strategy develops system resources on an annual basis, it even more closely matches projected load growth than would a regional nuclear approach.

Second, the regional nuclear approach, according to DEC, has a financial advantage because"[t]he substantial capital cost would be phased in over a longer period of time and would spread the risk if there were cost increases." *Id.* Again, the "High DSM" alternative strategy also has a financial edge because it has significantly lower capital costs than the equivalent nuclear resource; is phased in over a longer period of time than any of the nuclear resource options[9]; and is far less sensitive to risk of cost increases than is new nuclear capacity.

It should be noted that energy efficiency could also benefit financially from a regional approach, although DEC does not discuss this in its IRP. Regional marketing and partnerships with key efficiency vendors can help improve the effectiveness of programs in reaching customers and trade partners. For example, the Northwest Energy Efficiency Alliance currently manages six regional initiatives cooperatively funded by Bonneville Power Administration (representing approximately 130 public utilities), the Energy Trust of Oregon (working on behalf of Portland General Electric and Pacific Power) and 12 individual utilities.[10] The Northwest ENERGY STAR Homes Program resulted in a 13% electricity and 10% natural gas savings per ENERGY STAR certified home, with homes located in most or all utility service territories.[11]

Third, DEC states that a regional approach "would allow utilities to better optimize their portfolios as legislation or regulation change over time." *Id.* at 104. All of

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[9]In fact, about half of the capacity additions included in the High DSM alternative strategy occur in 2021 or later, after capital costs for the first nuclear units are fully committed. *See* 2011 IRP, Tables 4.A and 4.B at 34-35.

[10] Northwest Energy Efficiency Alliance, *A New Era of Energy Efficiency: 2009 Annual Report* (August 2010).

[11]KEMA, Inc., *Northwest ENERGY STAR Homes Energy Analysis: 2006-2007*, Northwest Energy Efficiency Alliance Report #10-217 (August 2010).

the portfolios DEC considered as alternatives to meet legislative or regulatory requirements included the High DSM strategy. Therefore, this third advantage is shared by the High DSM strategy.

D. The High DSM alternative would likely result in lower electric rates.

In addition to offering lower overall system costs, the High DSM alternative would likely reduce electric rates by as much as [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] in present value terms as compared to the "optimal plan," as illustrated by Table 1.

Table 1: Rate Impact of "Optimal" v. "High DSM" Plans[12]

[TABLE CONTAINS CONFIDENTIAL INFORMATION]

	"Optimal Plan"	"High DSM"	Difference
Cost	[redacted]	[redacted]	[redacted]
Cost per year (50 years)	[redacted]	[redacted]	[redacted]
Average Retail Sales (2015-2025)	[redacted]	[redacted]	[redacted]
Rate	[redacted]	[redacted]	[redacted]

Source: 2010 IRP Tables 4.1 and 4.2, DEC responses to data requests.

This rate reduction means that a decrease in DEC's revenue requirement due to lost sales is outweighed by the capital and production cost savings associated with selecting the High DSM strategy over the "optimal plan."

In light of the aforementioned benefits of DEC's High DSM case, DEC should have selected a preferred resource plan that incorporated an increased efficiency alternative, rather than the base case DSM assumptions.

IV. DEC FAILED TO PROPERLY CONSIDER ENERGY EFFICIENCY IN ITS EVALUATION OF RESOURCE OPTIONS.

Energy efficiency is the least-cost system resource. Unlike supply-side resources, energy efficiency, even at aggressive levels, reduces customer utility bills.[13] Energy efficiency can also moderate rate increases in the long-term by reducing or delaying the need for new generating capacity.[14] In fact, several states with leading energy efficiency programs have electricity rates comparable to, or even lower than, rates in South Carolina.[15] In addition to lower customer bills and long-term rate moderation, energy

[12]Table 1 uses the High DSM/Gas model results. Note that rate savings would be slightly higher with the High DSM/2N model results using 2010 IRP data.

[13]*See, e.g.* Marilyn A. Brown et al., Energy Efficiency in the South, Southeast Energy Efficiency Alliance (April, 12, 2010), http://www.seealliance.org/se_efficiency_study/full_report_efficiency_in_the_south.pdf.

[14]*Id.*

[15]John D. Wilson, Energy Efficiency Program Impacts and Policies in the Southeast (May 2009) at 4, http://www.cleanenergy.org/images/files/SACE_Energy_Efficiency_Southeast_May_20091.pdf.

efficiency reduces environmental impact and compliance costs, conserves water, reduces energy market prices, lowers portfolio risk, promotes local economic development and job growth, and assists low-income populations.[16]

Despite these benefits and the positive first-year results of its efficiency programs, DEC significantly underestimates the potential energy efficiency savings in its IRP. What follows is a brief discussion of DEC's efficiency program results and the role of efficiency in its long-term resource planning. A detailed analysis of DEC's energy savings and the integration of energy efficiency in its resource planning is provided in Attachment 1, "Review of Utility Evaluation of Energy Efficiency Resources in the Carolinas (October 2011)."

A. DEC's energy efficiency programs are off to an impressive start.

DEC is delivering good energy efficiency programs at low cost. In 2010, DEC exceeded its 2010 energy savings goals at a very low cost—the Company spent about two-third of its forecasted cost on a per-kWh basis, or $57 million, to achieve about 577 GWh of energy savings, or 0.7 percent of retail sales.

As discussed in Attachment 1, DEC achieved most of the energy and cost savings by investing heavily in residential lighting programs. DEC's success in delivering residential lighting savings demonstrates good program management: DEC used several different marketing and outreach techniques, which drove cost down and customer participation up, and resulted in impressive energy savings for a first-year effort. Petitioners applaud DEC for its program performance and urge the Company to continue its efforts.

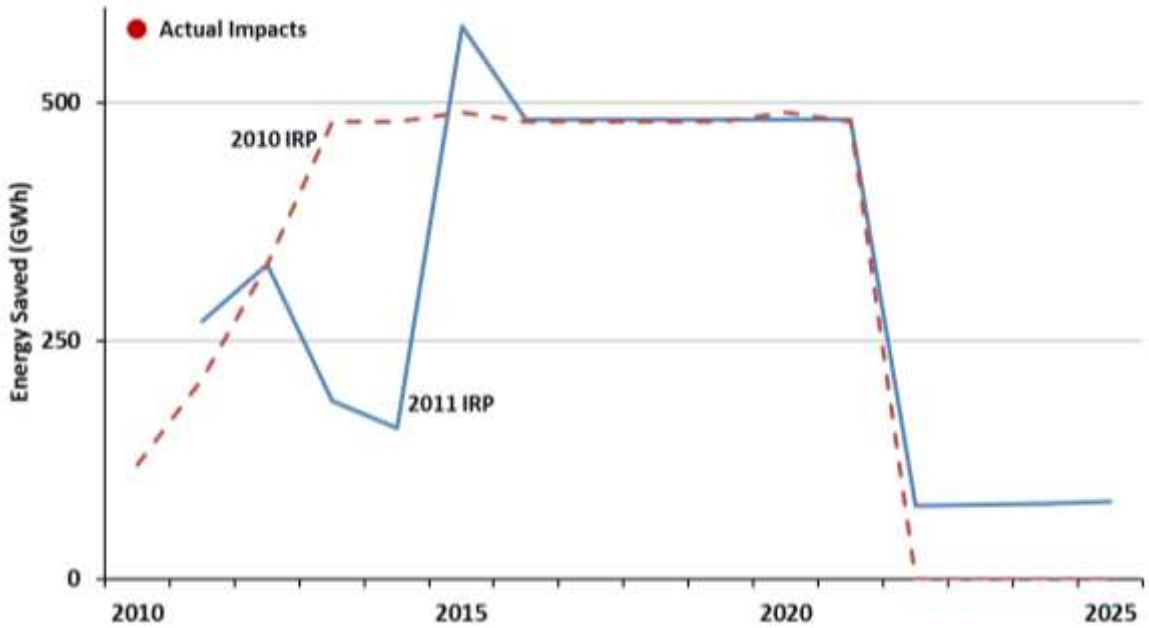
B. DEC's resource plan undervalues energy efficiency and projects a troubling decrease in efficiency in the long-term.

Despite the system-wide benefits of efficiency and impressive first-year performance, DEC's resource plan undervalues energy efficiency and suggests a significant decrease in efficiency savings over the planning period. DEC's resource plan reflects a long-term energy savings rate that is half the rate the Company achieved in 2010. Extrapolated over 15 years, the savings equivalent to 0.7 percent of retail sales that DEC achieved in 2010 would reach 11 percent by 2025, slightly more than the 10.6 percent savings that Duke considered in its High DSM portfolio and nearly two times greater than the 5.6 percent savings estimate represented by the Base DSM portfolio in the Company's selected plan. Thus, there is a stark and troubling contrast between the energy savings DEC could achieve by building upon its successful first year of efficiency programs versus what it has projected in its 2011 resource plan.

[16] *Supra* note 13. *See also Analyzing and Managing Bill Impacts of Energy Efficiency Programs: Principles and Recommendations,* Utility Motivation and Energy Efficiency Working Group, State and Local Energy Efficiency Action Network (July 2011) at 6, note 4.

Moreover, DEC's 2011 IRP reduces and delays the impact of energy efficiency resources as compared to the Company's 2010 IRP. As Figure 1 illustrates, DEC reduced its projected energy efficiency savings for the 2013-14 timeframe, even though actual program impacts in 2010 far exceeded the 2010 IRP estimates.[17] Compared to the 2010 IRP Base Case, the 2011 IRP Base Case (plus the actual impacts for 2010) reflect an 11 percent reduction in cumulative savings for the 2010-25 period.

Figure 1: Energy Savings as Estimated in Duke's 2010 and 2011 IRPs



Source: DEC 2010 IRP at 69-70; Duke 2011 IRP at 21, 23; and Direct Testimony of Timothy Duff, Exh. 2, DEC's Application for Approval of DSM and EE Cost Recovery Rider, NCUC Docket No. E-7, Sub 979.

DEC does not adequately explain these changes from the 2010 IRP. Although such projected changes in energy savings may not necessarily signal an actual change in DEC's medium-term plans for energy efficiency, they should be explained.[18] Figure 1 suggests that DEC's plans for energy efficiency include a two-year decrease in load impact (reduced energy savings from 2013-2014) followed by a more-than-doubling of impacts in 2015. It seems unlikely that DEC is planning its marketing and implementation contracts with slowdowns and ramp-ups in close succession. Therefore, we strongly recommend that DEC explain these changes.

[17] DEC made several additional adjustments to its Base and High DSM forecasts. For example, DEC aligned its High Case with the Base Case forecast in the near term. This is an appropriate planning practice, but the High DSM forecast is well below the medium- and long-term potential for energy savings.

[18] Indeed, if the change in energy savings forecasts from the 2010 to 2011 IRP does not represent DEC's efficiency plans, *i.e.* if DEC is managing the timing of and investment in its energy efficiency resources differently than it represents in this resource plan, this would suggest that DEC is not treating its demand-side resources on an equivalent basis with supply-side resources in its resource planning process.

In sum, DEC's resource plan for energy efficiency underestimates the opportunity for DEC to work with its customers to achieve energy efficiency savings. By discounting and constraining the role of the lowest-cost resource available to DEC and its customers, DEC's IRP could lead to unnecessarily-high capacity investments, with adverse impacts on customer costs, risks, and rates.

V. DEC OVERSTATES ITS NEED FOR NEW CAPACITY.

A. DEC uses an unreasonably high 17 percent reserve margin.

Duke assumes a 17 percent reserve margin over the planning period in its assessments of its load and resources and its need for new capacity. This reserve margin appears excessive when compared to reserve margins used by comparable utilities, such as Progress Energy Carolinas, Inc.'s ("PEC") 14-15 percent reserve margin.[19] Moreover, DEC has not shown that it needs a 17 percent reserve margin to ensure its ability to meet customer loads.

By using a more reasonable reserve margin, DEC could significantly reduce the need for new capacity while maintaining reliability. The use of a 15 percent reserve margin, for example, could reduce DEC's need for capacity by approximately 400 to 450 MW each year during the planning period.

In its Order on the 2010 North Carolina electric utility IRPs, the North Carolina Utilities Commission held that DEC (and PEC) should prepare a comprehensive reserve margin requirement study to be included as part of the 2012 IRP.[20]

B. DEC treats demand response as a resource option with its own reserve requirement, rather than as a load adjustment.

DEC's PowerManager, Interruptible Power Service, and Standby Generator Control programs are all load curtailment programs that are designed to reduce the Company's loads when necessary. 2011 IRP at 25-26. In calculating its system resource needs, DEC applies its 17 percent reserve margin to all of its loads, including those that will be curtailed under its demand response programs. After determining its required resources, which amounts to 1.17 times the load, DEC applies the demand response programs as a supply-side resource. This methodology of applying the reserve margin to demand response programs ignores the fact that these programs reduce load, and therefore results in overestimation of required reserves. Table 2 presents a hypothetical example assuming that DEC and PEC each has a load of 1000 MW and a reserve margin

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[19] DEC's affiliates in Indiana and Ohio use 13.8 percent and 15.3 percent reserve margin, respectively. *See, e.g.* Duke Energy Ohio's October 7, 2010 *Revised 2010 Electric Long-Term Forecast Report and Resource Plan*, at 144 and 145. Dominion North Carolina Power uses the 15.3 percent reserve margin recommended by PJM to develop "an effective 11 percent" reserve margin. *Dominion North Carolina and Dominion Virginia Power's Report of Its Integrated Resource Plan*, (September 1, 2010) at 4-3 and 4-4. SCE&G has determined that the appropriate level of reserves for its system is in the range of 12 percent to 18 percent. *See SCE&G's Integrated Resource Plan*, SCPSC Docket No. 2011-9-E (February 28, 2011) at 23.

[20] Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans, NCUC E-100 Sub 128 (October 26, 2011) at 7.

of 17%. As illustrated in Table 2, DEC's methodology results in a 16% increase in required reserves.

Table 2: Reserve Requirement Methodology

Reserve Requirement Method:	Duke	PEC*
Reserve margin	17%	17% (hypothetical)
Total load (hypothetical)**	1000	1000
Demand response as a reduction in load		75
Net load	1000	925
Required reserves	1170	1082
Current supply-side resources	1000	1000
Demand response as a supply side option	75	
Additional resources required	95	82
Percent of resource requirement related to applying demand response as a reduction in load	16%	

* The reserve requirement method used by PEC is shown using Duke's 17% reserve margin for illustrative purposes.

**The total system load is assumed to be 1000 MW in each instance.

Instead of applying the reserve margin to demand response programs, DEC should calculate its reserves, capacity margins and reserve margins on the basis of its firm loads, after accounting for demand response. In other words, demand response programs should reduce the load side of the calculation, which is the methodology employed by PEC. *See* PEC 2011 IRP at 26. Using this approach, DEC would reduce its required reserves and need for new capacity by about 160 MW beginning in 2015.[21]

VI. DEC SHOULD EVALUATE THE PRUDENCY OF CONTINUED OPERATION OF SCRUBBED COAL UNITS.

DEC currently owns eight coal-fired stations with a combined capacity of 7,535 MW in North and South Carolina. IRP at 13. Pursuant to the certificate of public convenience and necessity and air permits for Cliffside Unit 6, DEC must (1) retire Cliffside Units 1-4 upon starting up Unit 6; (2) retire an additional 800 MWs of coal capacity in 3 stages; and (3) take the additional steps needed to render Unit 6 carbon neutral by 2018. *Id.* at 48, 166. Based upon these legal requirements, and because of economic considerations, DEC plans to retire all of its remaining coal units without SO_2 scrubbers by 2015, although it allows itself some flexibility in terms of the specific units to be retired and/or their exact retirement dates. *Id.* at 48-50. While the retirement of

[21] DEC assumes that its demand response programs will total over 980 MW each summer beginning in 2015. 2011 IRP at 87.

old, unscrubbed coal units makes clear economic sense, the continued operation of certain scrubbed coal-fired units may also be imprudent.

There are several pending and imminent EPA regulations that would render it economically unwise to continue to operate many of these units, including EPA's forthcoming Utility Maximum Achievable Control Technology ("Utility MACT") rule. *Id.* at 7. The final Utility MACT rule is expected later this year. Once EPA promulgates the Utility MACT rule, the Clean Air Act mandates that all covered sources must comply with its provisions within 3 years, or by 2015. The Utility MACT is just one of the regulatory risks facing existing coal-fired units that will require capital investments and increase operating expenses. Other EPA regulations impacting existing coal units include greenhouse gas regulations, regulations under Section 316(b) of the Clean Water Act, new steam electric effluent guideline, the Cross State Air Pollution Rule, National Ambient Air Quality standards for ozone and SO_2 and new coal combustion waste regulations

DEC discusses the legislative and regulatory risks facing the Company's coal-fired units, and sensibly concludes that all unscrubbed coal will be retired by 2015. 2011 IRP at 7-8. However, these risks are not confined to unscrubbed existing coal units. Scrubbed units face many of the same risks as do the unscrubbed units that DEC is planning to retire, including but not limited to the need to further reduce their emissions of mercury and other hazardous air pollutants, the need to convert from once-through to closed-cycle cooling, and the need to update liquid and solid waste handling techniques.

DEC's IRP contains no analysis of the risks faced by its existing scrubbed coal plants or assessment of what additional pollution controls, such as baghouses and activated carbon injection, will be needed at each of these units. This is a serious flaw. DEC must "meet[] the requirements shown in its forecast in an economic and reliable manner."[22] It therefore should account for all the cost and risk that its coal units bear. The IRP should reflect an evaluation of whether it will be more economic to retire certain scrubbed coal units, or repower them, rather than investing significant capital in pollution control equipment and other infrastructure necessary to comply with impending regulations.

[22] Commission Order No. 1998-502; S.C. Code Ann. § 58-37-10 (2010).

VII. DEC HAS UNREALISTIC ASSUMPTIONS ABOUT NUCLEAR GENERATION.

A. DEC's assumptions about the timing of new nuclear units are unrealistic.

According to the IRP, DEC plans to begin operations at Lee Station Units 1 and 2 in 2021 and 2023, respectively.[23] This schedule is highly uncertain for several reasons:

- The Advanced Light Water Reactor designs currently being considered for construction in the region (including the AP1000 design being considered by DEC, as well as by SCE&G and Southern Company) are untested designs – design certification by the Nuclear Regulatory Commission ("NRC") does not guarantee that the total plant design will be without flaws or that significant problems will not be experienced during construction.
- It is uncertain when the NRC will issue a Combined Construction and Operation License for the Lee Nuclear Station or other nuclear power plants in the region and, consequently, when major construction actually will begin.
- Supply chain bottlenecks or constraints and/or transportation delays may lead to longer than expected lead times for critical plant equipment, especially if multiple nuclear construction projects are competing for limited engineering and construction resources and limited equipment manufacturing capacity.

New generation nuclear plants have experienced significant construction delays. For example, the Olkiluoto 3 power plant in Finland, the first "new generation" nuclear unit to begin construction, broke ground in 2005 with a scheduled completion date of 2009. The plant, which uses a European Pressurized Water Reactor ("EPR") design, has experienced many problems, and its estimated completion date has been pushed back to the end of 2012, with a scheduled start of operations in early 2013.[24] Additionally, the projected cost of the plant has increased by more than 70 percent or about $4 billion.[25] A second EPR project in France, the Flamanville plant, has also experienced significant construction and schedule problems.[26] Construction on that plant began in late 2007 and was expected to last until mid-2012. As of 2010, the estimated cost of the Flamanville project has increased by 50 percent to 5 billion euros and the start of commercial operations has been delayed by approximately two years until 2014.[27] Based on the

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[23] DEC also assumes that it could add substantial amounts of new nuclear capacity as early as 2016 and 2017 in at least one of its sensitivity analyses. This is highly unlikely because the Company does not even plan to begin site preparations at the Lee Nuclear Station until around 2014.

[24] http://www.world-nuclear-news.org/NN-Startup_of_Finnish_EPR_pushed_back_to_2013-0806104.html

[25] *Id.*

[26] *See, e.g.,* "Regulator stops flow of concrete at Flamanville," *Nuclear Engineering International* (June 18, 2008) at 4.

[27] Tara Patel, "French Nuclear Watchdog Says EDF Has Problems With Flamanville EPR Liner," Bloomberg, (August 30, 2010), http://www.bloomberg.com/news/2010-08-30/edf-has-welding-problems-at-flamanville-epr-reactor-french-watchdog-says.html.

foregoing, DEC's ambitious schedule for Lee is far from certain, and that uncertainty should be acknowledged as a matter of sound planning practice.

B. The cost of new nuclear units will likely be significantly higher than the amount DEC assumes in its resource planning analyses.

DEC assumes that the cost of building twin AP1000 nuclear units at the proposed Lee Nuclear Station site in South Carolina will cost $11 billion in 2010 dollars. Even if DEC has correctly estimated the "overnight" cost of new nuclear units, when financing costs and the impacts of inflation are added, the total cost of a two-unit nuclear plant far exceed this amount. DEC has not provided any supporting evidence that form the basis of its cost estimate.

Starting in the 1970s, the costs of building new nuclear power plants began to increase significantly. Actual costs of new plants were two to three times higher than the cost estimates provided during licensing or at the start of construction. The nuclear industry has a poor track record in predicting plant construction costs and avoiding cost overruns. Indeed, as Table 3 illustrates, a U.S. Department of Energy study shows that the costs overrun for the construction of 75 nuclear power plants was more than 200 percent above initial cost estimates.

Table 3[28]

Projected and Actual Construction Costs for Nuclear Power Plants

Construction Starts		Average Overnight Costs[a]		
Year Initiated	Number of Plants[b]	Utilities' Projections (Thousands of dollars per MW)	Actual (Thousands of dollars per MW)	Overrun (Percent)
1966 to 1967	11	612	1,279	109
1968 to 1969	26	741	2,180	194
1970 to 1971	12	829	2889	248
1972 to 1973	7	1,220	3,882	218
1974 to 1975	14	1,263	4,817	281
1976 to 1977	5	1,630	4,377	169
Overall Average	**13**	**938**	**2,959**	**207**

Source: Congressional Budget Office (CBO) based on data from Energy Information Administration, An Analysis of Nuclear Power Plant Construction Costs, Technical Report DOE/EIA-0485 (January 1, 1986).

Notes: Electricity-generating capacity is measured in megawatts (MW); the electrical power generated by that capacity is measured in megawatt hours (MWh). During a full hour of operation, 1 MW of capacity produces 1 MWh of electricity, which can power roughly 800 average households.
The data underlying CBO's analysis include only plants on which construction was begun after 1965 and completed by 1986.
Data are expressed in 1982 dollars and adjusted to 2006 dollars using the Bureau of Economic Analysis's price index for private fixed investment in electricity-generating structures. Averages are weighted by the number of plants.

a. Overnight construction costs do not include financing charges.
b. In this study, a nuclear power plant is defined as having one reactor. (For example, if a utility built two reactors at the same site, that configuration would be considered two additional power plants.)

[28]Congressional Budget Office, *Nuclear Power's Role in Generating Electricity,* May 2008, at 17.

Nuclear cost estimates are highly uncertain. DEC has a +20 /-10 percent sensitivity range for the cost of the Lee Nuclear Station. IRP at 100. However, based on the significant cost overruns discussed about, this range appears to be insufficient.[29] Sound resource planning would acknowledge these significant uncertainties and the likelihood of cost escalations.

VIII. MODELING OF ECONOMIC IMPACTS WOULD INFORM THE EVALUATION OF RESOURCE PORTFOLIOS.

IRPs must include a description of the economic consequences of the plan to the extent practicable. *See* Commission Order No. 1998-502; S.C. Code Ann. § 58-37-10 (2010). Major utilities across the country perform modeling and analyses to estimate the economic impacts of their resource planning decisions, and DEC and its ratepayers would be well served if that approach were adopted in DEC's IRP. Information about economic impacts would assist DEC, the commissions and interested parties in understanding the broader implications of the Company's resource planning decisions.

Specifically, DEC should consider using the REMI Policy Insight model, a tool for conducting economic impacts analyses of resource planning portfolios that has been called the "most sophisticated" approach for conducting economic analysis of energy policies or projects.[30]

A 2010 study on Wisconsin's energy efficiency and renewable energy programs illustrates how the REMI Policy Insight model can be used to cover "all aspects of changes in the economy," including changes in business sales, gross regional product, real after-tax income, and jobs.[31] In that study, the REMI model showed various economic development impacts of efficiency and renewable energy programs, including lower energy costs, increased "business competitiveness," and a lower cost of living, which in turn increased the attractiveness of the state as a place to live and work.[32] Figure 2 shows the REMI model estimates of the job impacts of Wisconsin energy efficiency and renewable energy programs.

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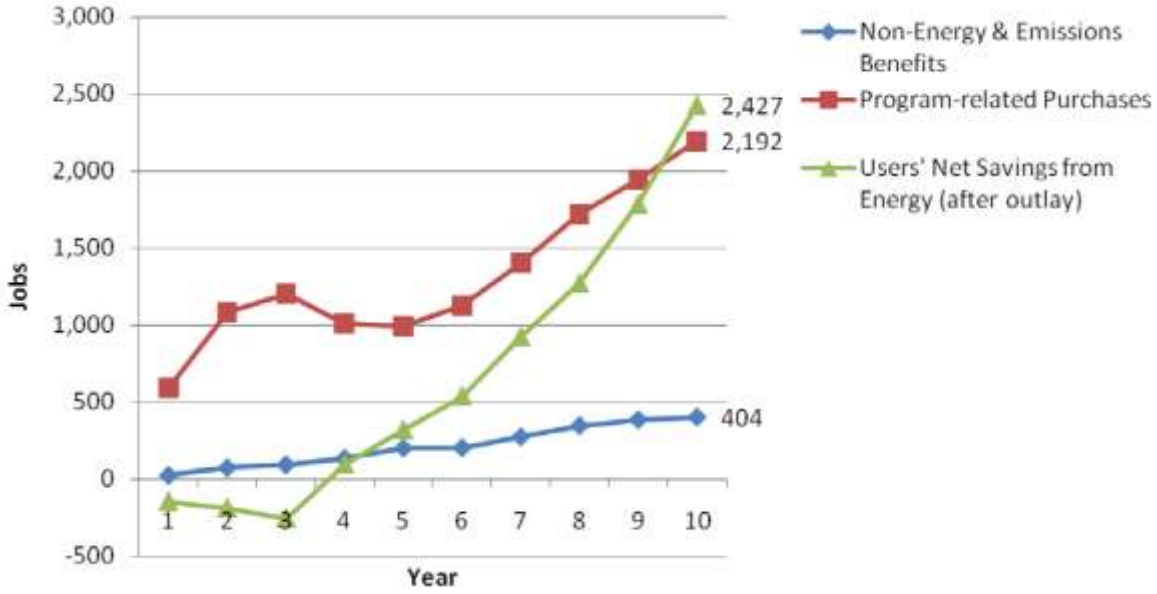
[29] Indeed, former Duke Chief Operating Officer and Group Executive Vice President, James Turner, noted that it is not unreasonable for Duke assume and plan for significant cost overruns, in the 40-50% range, for its proposed Lee units. *See* DEC Reply Comments, NCUC Docket No. E-100, Sub 128 (March 1, 2011) at 32.

[30] U.S. Environmental Protection Agency, *Assessing the Multiple Benefits of Clean Energy: A Resource for States*, Climate Protection Partnerships Division. EPA also has noted that REMI Policy Insight model must be used with care so as to avoid unreliable findings, as seen in the Tennessee Valley Authority's draft resource planning documents recently presented for public comment.

[31] Economic Development Research Group (EDRG), *Focus on Energy Evaluation, Economic Development Benefits: CY09 Economic Impacts*, report to Public Service Commission of Wisconsin, March 2, 2010.

[32] *Id.*

Figure 2: REMI Model Estimates of Job Impacts of Wisconsin EE/RE Programs



Economic Development Research Group (EDRG), *Focus on Energy Evaluation, Economic Development Benefits: CY09 Economic Impacts*, report to Public Service Commission of Wisconsin, March 2, 2010.

Similar information on the economic impacts of DEC's IRP would help the Company evaluate, estimate and describe the economic consequences of its resource options.

In conclusion, DEC's 2011 IRP does not reflect a long-term plan to meet its customers' energy needs in the most economic and reliable manner. While DEC's energy efficiency programs are performing well, and we support the Company's efforts, DEC declined to select an aggressive efficiency case that would lower customer cost and risks. In fact, DEC's plan reduces the long-term savings impact of energy efficiency by 11% as compared to the 2010 IRP. On the supply side, DEC overstates the Company's need for new generating capacity due in part to high reserve margins; does not adequately address the economics of the continued operation of scrubbed coal units; and adopts unrealistic assumptions about the cost of new nuclear generation in its IRP. A proper analysis of alternative resource mixes would result in a preferred resource portfolio that reflects, among other things, increased energy efficiency in the long-term, a reduced need for additional generation, and retirement of uneconomical existing coal units.

Respectfully submitted this 31st day of October, 2011.

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Attachment 1

Review of Utility Evaluation of Energy Efficiency Resources in the Carolinas (October 2011)[1]

Energy efficiency is the least-cost electric system resource. Unlike supply-side resources, energy efficiency, even at aggressive levels, reduces customer utility bills.[2] Energy efficiency also moderates rate increases by reducing or delaying the need for new generating capacity.[3] In fact, states with leading energy efficiency programs often have electricity rates that are comparable to, or even lower than, rates in North and South Carolina.[4] In addition to lower customer bills and rate moderation, the numerous benefits of energy efficiency include environmental quality improvements, water conservation, energy market price reductions, lower portfolio risk, economic development and job growth, and assistance for low-income populations.[5]

Despite these well-recognized benefits, electric utilities in North and South Carolina ("Carolinas utilities")[6] significantly underestimate and underutilize the energy efficiency resource in their integrated resource plans ("IRPs"). Best IRP practices evaluate the efficiency resource on an equivalent basis with supply-side resources.[7] Carolinas utilities do not implement these best practices in a systematic way, however, and therefore fail to give due consideration to available and emerging energy efficiency resource opportunities. As a result, Carolinas utilities continue to develop IRPs that favor more expensive, risky supply-side resources and do not result in the "least-cost mix" of resource options. Leading utilities in many states expect to achieve more energy efficiency savings in the next five years than Carolinas utilities anticipate achieving in the next ten or even fifteen years. Carolinas utilities can and should do better.

What follows is a review of the manner in which Carolinas utilities consider energy efficiency as a resource. The following conclusions and recommendations are presented:

- Long-term efficiency savings projections of DEC and PEC lag behind those of leading utilities, even though DEC and PEC achieved impressive first-year savings impacts. DEC and PEC must build upon their first-year results to realize

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[1]This review was conducted by the Southern Alliance for Clean Energy.

[2] *See, e.g.*, Marilyn A. Brown et al., Energy Efficiency in the South, Southeast Energy Efficiency Alliance (April, 12, 2010), http://www.seealliance.org/se_efficiency_study/full_report_efficiency_in_the_south.pdf.

[3] *Id.*

[4]John D. Wilson, Energy Efficiency Program Impacts and Policies in the Southeast (May 2009) at 4, http://www.cleanenergy.org/images/files/SACE_Energy_Efficiency_Southeast_May_20091.pdf.

[5]*Supra* note 2.

[6]Unless otherwise noted, the current version of this review covers Duke Energy Carolinas, LLC ("DEC") and Progress Energy Carolinas, Inc. ("PEC") only. Future versions will cover additional electric utilities.

[7]S*ee* National Action Plan for Energy Efficiency Leadership Group, *National Action Plan for Energy Efficiency* (July 2006), Chapter 3.

the cumulative savings potential of energy efficiency, and the long-term system-wide benefits it offers customers and utilities.

- Industrial opt-out provisions create a lost energy savings opportunity. DEC and PEC should improve the quality of their programs directed to large commercial and industrial customers to realize the significant savings potential of this energy-intensive customer sector. Additionally, industrial customers who opt-out must implement their own efficiency measures, and the program impacts should be accounted for in the utilities' resource plans.

- DEC and PEC have not used a complete energy efficiency resource analysis in developing their IRPs. Utilities must rely on both existing and new energy efficiency technologies throughout their resource planning horizons. They should conduct comprehensive, independent energy efficiency potential studies and/or set energy savings goals based on available evidence regarding the amount of cost-effective energy efficiency that is achievable.

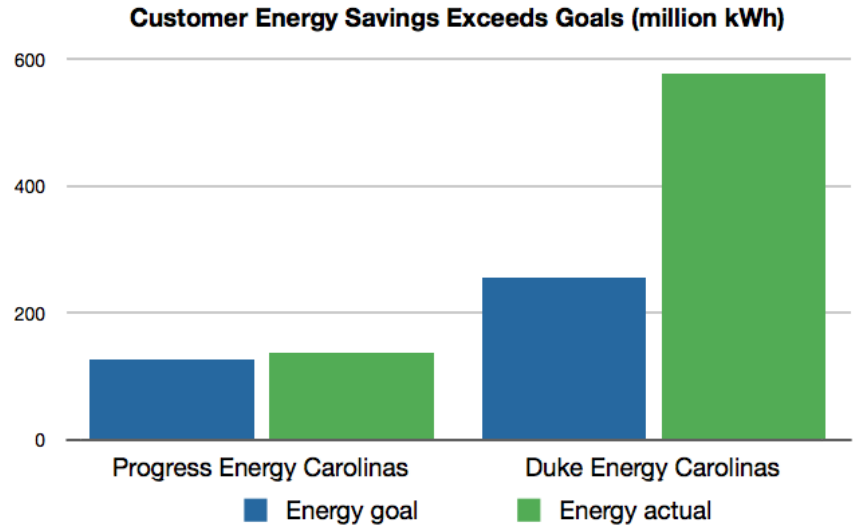
- Utility resource planning models do not optimize cost-effective energy efficiency in portfolio outputs. Rather than treating efficiency as a fixed load modifier, DEC and PEC should use an approach that models energy efficiency as a resource, just as generating plants are modeled on the supply side, such as the two-supply curve approach used by the Northwest Power and Conservation Council.

1. DEC and PEC have achieved substantial first-year efficiency savings but their long-term savings projections lag behind those of leading utilities.

The cumulative impact of DEC's and PEC's energy efficiency programs could reach the levels achieved by leading utilities over the next ten to fifteen years if DEC and PEC adequately analyze and forecast demand-side resources. While DEC and PEC have improved their consideration of energy efficiency in selecting near-term resource options, they still do not adequately consider energy efficiency in the long-term.

DEC and PEC have begun to invest in energy efficiency at meaningful levels. For their first full program year, DEC and PEC exceeded their energy savings targets, as illustrated in Figure 1.

Figure 1: Energy Efficiency Program Impacts, First Full Program Year



Source: SACE analysis of PEC and DEC compliance filings in North and South Carolina. PEC data cover April 2010-March 2011; DEC data cover calendar year 2010.

Typically, ambitious new programs save 0.2 – 0.5% of retail electricity sales in their first full program year. As Table 1 shows, DEC and PEC's first year program impact are within or exceed this range. DEC is outperforming PEC in terms of energy efficiency savings, mostly due to DEC's aggressive residential lighting efforts.

Table 1: Energy Efficiency Program Impacts, First Full Program Year

Program impact (relative to electricity sales)	**PEC**	**DEC**
Efficiency from residential lighting programs	0.20%	0.52%
Efficiency from all other programs	0.13%	0.13%
Total efficiency savings	**0.33%**	**0.65%**

Source: SACE analysis of PEC and DEC compliance filings in North and South Carolina. PEC data cover April 2010-March 2011; DEC data cover calendar year 2010.

Both utilities have made residential lighting incentives, which focus on CFL bulbs, their largest and lowest-cost efficiency program. Over the next decade, federal lighting standards will increase the efficiency of many bulbs, which will benefit consumers, but also raise the bar for utilities to capture lighting savings because the utility will get credit only for energy savings that go beyond existing standards.

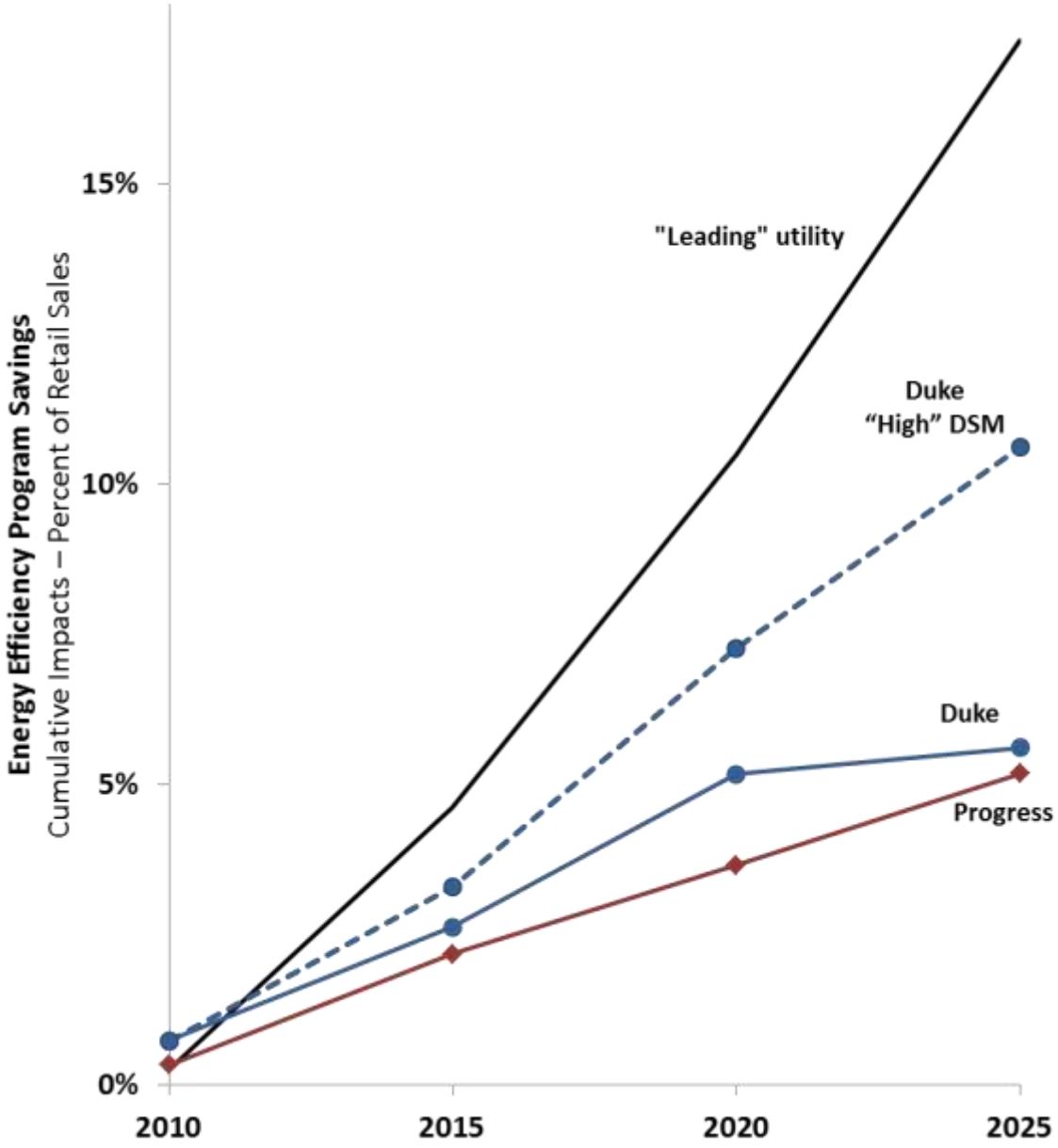
Despite the initial success of the DEC and PEC programs, the Carolinas remain in the bottom quarter compared to states with energy efficiency standards. PEC and DEC expect to achieve about 3.7% and 5.2%, respectively, in cumulative energy savings from energy efficiency programs by 2020. These forecasts are equivalent to annual energy savings of 0.37% and 0.52%—significantly below the levels achieved by national leaders. Figure 2 compares projected energy efficiency savings of DEC and PEC to that of a "leading" utility from the average "top ten" state, which is anticipated to achieve at

least 1% annual energy savings per year.[8] A 1% annual savings goal is consistent with the findings of recent studies, including a 2010 Georgia Tech meta-analysis of several potential studies in the South, which found that the achievable electric efficiency potential ranges from 7.2 to 13.6% after 10 years.[9]

[8]The "leading" utility is represented as the average of the top ten states as reported in Sciortino, M. *et al*., *Energy Efficiency Resource Standards: A Progress Report on State Experience*, American Council for an Energy-Efficient Economy, Research Report U112 (June 2011).

[9]Chandler, S. and M.A. Brown, "Meta-Review of Efficiency Potential Studies and Their Implications for the South," Working Paper # 51 (August 2009). *See also* American Council for an Energy-Efficient Economy, "North Carolina's Energy Future: Electricity, Water, and Transportation Efficiency," Report Number E102, March 2010, at 15 (finding that the "medium case" energy savings potential for utility-led energy efficiency programs is approximately 17% by 2025).

Figure 2: Energy Efficiency Savings Impacts of DEC and PEC Compared to "Leading" Utility



Source: DEC 2011 IRP at 23, 119-121; PEC 2011 IRP at 8, E-9; and Sciortino, M. *et al*, *Energy Efficiency Resource Standards: A Progress Report on State Experience*, American Council for an Energy-Efficient Economy, Research Report U112 (June 2011).

Figure 2 shows that Carolinas utilities lag significantly behind the typical leading utility, regardless of which baseline is used. DEC's energy efficiency program impacts appear to grow during the first decade of the planning horizon, but level off in the second decade. PEC projects increased energy savings in the second decade of its planning horizon, but only enough to account for slow growth in its efficiency program impacts in the first decade. As a result, while aggressive levels of energy efficiency may be sufficient to eliminate a large amount of load growth through about 2020, the efficiency

projections in DEC's and PEC's IRPs favor supply-side additions in the second decade of the planning period, despite available, additional savings opportunities from energy efficiency. Energy efficiency, if properly integrated into a long-term resource plan, can result in steady, significant energy savings growth over the planning horizons. DEC and PEC should build upon their successful first-year energy savings results to realize the long-term system-wide benefits of efficiency, which will lower cost and risk to both customers and the utilities.

2. Industrial opt-out provisions create a lost energy savings opportunity.

In both North and South Carolina, industrial customers can choose to opt out of utility-sponsored energy efficiency programs, and not bear the costs of new programs, if they implement their own energy efficiency programs. Opt-out provisions do not exempt industrial customers from engaging in energy efficiency efforts altogether. Instead, they allow industrial customers to opt out of utility programs only if they implement their own energy efficiency programs.

It does not appear that the load impact from industrial energy efficiency efforts is reflected in the utilities' IRPs. While DEC accounts for the impact of federal lighting standards on its load forecasts,[10] it does not make a similar adjustment for the impact of energy efficiency programs adopted by industrial customers that have opted out of its programs. (PEC does not make this adjustment either). Moreover, PEC appears to have no expectation that customers eligible to opt-out will implement all cost-effective energy efficiency: its energy efficiency study excludes the participation of ***all customers*** eligible to opt-out of DSM programs.[11]

Industrial and large commercial sectors represent a large resource opportunity: more than half of the cost-effective energy efficiency potential. Failure to utilize this resource opportunity increases system costs for all classes of customers.

DEC's discussion of the cost difference between its "base" and "high" energy efficiency cases illustrates the significance of this lost opportunity. DEC acknowledges that "[t]he high energy efficiency sensitivity is cost effective if there is an equal participation between residential and non-residential customers" but that "[i]f a significant number of non-residential customers opt out, then the high EE case may no longer be cost effective."[12] Indeed, DEC's supporting data suggests that if more industrial customers were to participate in DEC's efficiency programs, DEC could increase energy efficiency savings from about 5% to about 11%, and reduce or delay costly new supply-side resources.[13]

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[10]Duke 2011 IRP at 110.
[11]ICF International, *Progress Energy Carolinas DSM Potential Study* (March 16, 2009) at 2-13.
[12]Duke 2010 IRP at 95.

[13]Initial Comments of Southern Alliance for Clean Energy, *In re: Investigation of Integrated Resource Planning in North Carolina–2010*, North Carolina Utilities Commission Docket No. E-100, Sub 128 (February 10, 2011) at 11.

Several steps could be taken to address the impact of industrial opt-outs. First, the electric utilities could, at their own initiative or at the direction of state commissions, improve the quality of their programs directed to large commercial and industrial customers. The increasing number of "opt-ins" indicates that the utilities have made some efforts in this regard, and we encourage DEC and PEC to continue this effort. Second, the commissions or the utilities could initiate a process to ensure that industrial customers who opt-out actually implement their own efficiency measures, as required. Third, industrial customers or their customer associations could work to provide to the electric utilities firmer estimates of their energy efficiency plans and projected impacts on energy use and demand. Fourth, utilities, industrial customers and others could work together to develop more attractive programs that meet the needs of industrial customers.

3. DEC and PEC do not conduct complete energy efficiency resource analyses in developing their IRPs.

DEC and PEC are not using a comprehensive energy efficiency potential study, or a consistent standard in determining the amount of energy savings that can be achieved, in their resource planning processes.

For its 2010 IRP, DEC limited the program potential of its "high energy efficiency" forecast to the "economic potential identified by the 2007 market potential study."[14] In a recent hearing before the North Carolina Utilities Commission, DEC Witness Richard Stevie testified that this study is "out of date" and that DEC is "continuing to look at additional programs" that were not analyzed in the potential study.[15] While the "high energy efficiency" forecast in the DEC 2011 IRP has a similar level of cumulative savings, it is unclear whether DEC continues to limits its program potential by the amount identified in the 2007 market potential study.[16]

For its 2010 and 2011 IRPs, PEC limits its program potential to the "cost-effective, realistically achievable potential" in its "updated potential study."[17] While the scope of PEC's updated study appears to be broader than that of the earlier version, the study appears to suffer from the same fundamental shortcomings as the earlier study, which include:

- The potential study indicates that the findings were benchmarked against other utilities but no benchmarking is disclosed.
- Energy savings practices, measures and entire sectors remain excluded from the scope of study.

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[14] Duke 2010 IRP at 68.

[15] North Carolina 2008 and 2009 IRP hearing, Transcript Vol. 4, pp. 31 and 39.

[16] *Compare* Duke 2011 IRP at 34 (describing the high EE load impact scenario as using the full target impacts of the Save-A-Watt programs for the first five years and then increasing the load impacts at 1% of retail sales *every year after that until 2030*) *with* Duke 2011 IRP at 101 (defining the High DSM case as the full target impacts of Save-A-Watt for the first five years and then increasing load impacts at 1% of retail sales every year after that *until the load impacts reach the economic potential identified by the 2007 market potential study*).

[17] Progress 2010 IRP at E-7.

- It is not evident from the resource plan that PEC has made effective use of the insights offered by its consultant in the potential study. It does not appear that PEC has adopted some highly cost-effective programs and strategies included in PEC's market potential study, such as an ENERGY STAR Appliance program and certain non-residential incentive programs.

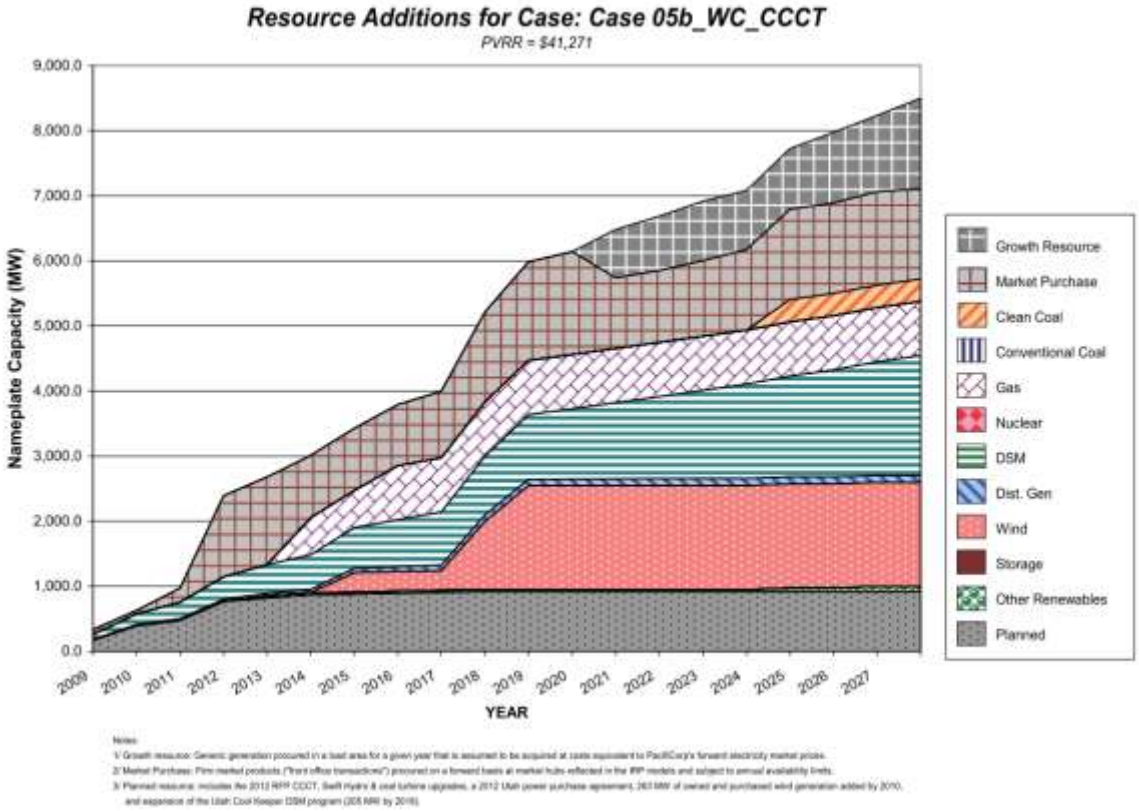
In its IRP, PEC effectively assumes no further technological progress or development of new energy-saving practices. DEC is more confident about advances in efficiency, although this is not fully reflected in its long-term resource plan.

Utilities across the country that have a serious commitment[18] to efficiency, rely on both existing and new energy efficiency technologies throughout their resource planning horizons to achieve energy savings in both the near- and long-term. The Northwest Power and Conservation Council, for example, has concluded that at least 85% of the projected 20-year energy savings estimates in its first regional plan were realized.[19] One of the utilities affected by those regional plans, PacifiCorp, anticipates continued growth of the contribution of DSM resources in its IRP, as illustrated in Figure 3.

[18] The term "serious commitment" is used to reflect a plan to achieve more than 3% energy savings over 10 years – a relatively low threshold.

[19] Northwest Power and Conservation Council, *Achievable Savings: A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions*, Council document 2007-13, August 2007.

Figure 3: PacifiCorp Preferred Resource Portfolio, 2008 IRP



PacifiCorp, *2008 Integrated Resource* Plan, May 2009, Volume I, at 239 and Appendix A, at 31.

DEC and PEC can and should do the same. Indeed, "[m]ost utilities have an established approach to forecast long-term market prices, and the same forecasting technique and assumptions should be used for energy efficiency as are used to evaluate supply-side resource options."[20]

There are several steps that could be taken to help utilities in the Carolinas move toward a more complete energy efficiency analysis. One option is to rely upon a comprehensive, independent energy efficiency potential study. Such a study should be conducted without incorporating utility biases that could constrain the findings; should recognize the limitations inherent in such studies, particularly with respect to quantifying what is "achievable"; and should make reasonable assumptions about long-term technological and program development prospects.

Second, the utilities could conduct more limited studies to address specific shortcomings, such as the failure to study different business sectors for energy savings opportunities. This would partially address the gaps in the existing studies and could lead more directly into program development.

[20]National Action Plan for Energy Efficiency Leadership Group, *National Action Plan for Energy Efficiency* (July 2006), at 3-4.

A third option is to set an energy savings goal. Such a goal may be set by the state legislature or by a regulatory commission, for example, and would be based on available evidence regarding what level of cost-effective energy efficiency is achievable, and would be subject to future revision. Although there may be imprecision and a potential for bias or error, a goal can be implemented in a constructive and positive manner, with flexibility and accountability for results that are truly in the public interest.

4. Utility resource planning models do not optimize cost-effective energy efficiency in portfolio outputs.

In their resource planning modeling, DEC and PEC integrate energy efficiency as a fixed model input, best characterized as a load adjustment. As a result, the resource planning model works around the limited efficiency input, selecting resources to meet the utility's adjusted load. While this treatment is appropriate for demand response, industry best practice is to treat energy efficiency as equal or even preferred to supply-side resources for planning purposes.[21]

Utilities in the Carolinas should use an approach that models energy efficiency as a resource, just as generating plants are modeled on the supply side. For example, the Northwest Power and Conservation Council has pioneered an approach that uses two supply curves for energy efficiency in the model that develops least-cost portfolios.[22] The use of two supply curves allows for different treatment of discretionary and lost-opportunity energy efficiency resources.[23] Just as utilities use short-term market power purchases for different purposes than investments in new power plants, a sophisticated energy efficiency planning process distinguishes between discretionary and lost-opportunity resources. The load-adjustment approach does not allow this distinction to be made.

Unless an aggressive energy savings target is set by a legislature or commission, we recommend that utilities in the Carolinas adopt a two-supply-curve approach to evaluate the energy efficiency resource in their IRP processes. At a minimum, the utilities should model energy efficiency on an equivalent basis to supply-side resources. This would be preferable to the "adjusted load" method that does not account for all cost-effective energy efficiency and therefore leads to resource portfolios with unnecessarily high levels of both cost and risk.

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[21] *See, e.g.*, Aspen Environmental Group and Energy and Environmental Economics, Inc. (Aspen/E3), *Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California: Final Report and Appendices*, prepared for California Public Utilities Commission, April 2009, http://docs.cpuc.ca.gov/published/Graphics/103213.PDF.

[22] *Id.* at 71.

[23] Discretionary energy efficiency resources are investments that can be advanced or deferred based on near-term market decisions, such as a CFL market promotion. Lost-opportunity energy efficiency resources are programs that take advantage of opportunities due to market or customer circumstances, such as new construction and replace-on-burnout programs.

Attachment 2
Cost Comparison of Duke's "High DSM" and "Base DSM" Portfolios

Year	Selected "Base DSM" Portfolios				Selected "High DSM" Portfolios					
	CT/CC	2N 2021-2023, "Optimal Plan"	2N 2026-2028	1N 2027	HDSM Gas	HDSM 2N 2021-2023	HDSM 2N 2026-2028	HDSM 1N 2027	Clean Energy Gas	Clean Energy 1N
2011-16										
2017	CC	CT	CT	CT						
2018					CC	CT	CT	CC		
2019	CT	CT	CT	CT					CC	CC
2020					CT	CT (PPA)	CT	CT	CT	CT
2021	CC	N	CC	CC		N				
2022										N
2023	CC	N	CC	CC	CC	N		CT	CC	
2024										
2025	CC		CT(PPA)	CC	CT					
2026	CC		N				N	CT(PPA)		
2027		CC		N				N		
2028	CT		N		CC		N		CT	CT
2029		CC		CT		CT				
2030	CT	CT	CT	CT	CT	CT		CT	CT	CT
CT	2,050 MW	1,780 MW	1,780 MW	2,240 MW	1,890 MW	1,600 MW	2,200 MW	2,070 MW	1,690 MW	1,880 MW
CC	3,250 MW	1,300 MW	1,300 MW	1,950 MW	1,950 MW	0 MW	0 MW	650 MW	1,950 MW	650 MW
Nuclear	-	2,234 MW	2,234 MW	1,117 MW	0 MW	2,234 MW	2,234 MW	1,117 MW	-	1,117 MW
N. Uprate	204 MW	204 MW	204 MW	204 MW	204 MW	204 MW	204 MW	204 MW	204 MW	204 MW
Retire	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW	2,017 MW
DSM	1,900 MW	1,900 MW	1,900 MW	1,900 MW	3,188 MW	3,188 MW	3,188 MW	3,188 MW	1,900 MW	3,188 MW
Portfolio NPV Costs ($million)										
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NPV Cost Difference ($billion) (higher values in parentheses represent greater cost savings relative to the "Optimal Plan")										
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]