SOUTHERN ENVIRONMENTAL LAW CENTER

Telephone 919-967-1450 | 601 WEST ROSEMARY STREET, SUITE 220
CHAPEL HILL, NC 27516-2356 | Facsimile 919-929-9421

April 11, 2014

<u>*Via Electronic Filing*</u>

Ms. Gail Mount
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

RE: Investigation of Integrated Resource Planning in North Carolina - 2013
Docket No. E-100, Sub 137

Dear Ms. Mount:

Enclosed for filing in the referenced docket on behalf of Southern Alliance for Clean Energy and the Sierra Club are the following documents:

- **Confidential Version** of *Initial Comments of Sierra Club and Southern Alliance for Clean Energy*. This document contains confidential data and should be filed under seal. The confidential information is indicated by gray shading in the text of the comments.

- **Redacted Version** of *Initial Comments of Sierra Club and Southern Alliance for Clean Energy*. This version can be made available to the public.

By copy of this letter, I am serving a copy of the Redacted Version of the Comments on all parties of record. Copies of the Confidential Version will be provided upon request to parties who have executed appropriate confidentiality agreements. Please let me know if you have any questions about this filing.

Sincerely,

s/ Robin G. Dunn
Administrative Legal Assistant

RGD
Enclosures
cc: Parties of Record

PUBLIC VERSION—CONTAINS REDACTED INFORMATION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 137

In the Matter of:	)
	) **INITIAL COMMENTS OF**
Investigation of Integrated Resource	) **SIERRA CLUB AND SOUTHERN**
Planning in North Carolina – 2013	) **ALLIANCE FOR CLEAN ENERGY**
	)

PURSUANT TO North Carolina Utilities Commission Rule R8-60(j) and the Commission's March 13, 2014 Order Granting Further Extension of Time, intervenors Southern Alliance for Clean Energy ("SACE") and the Sierra Club, through counsel, file these initial comments on the 2013 Integrated Resource Plans ("IRPs") of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, Inc. ("DEP")(collectively, "Duke Energy" or the "companies").

I. SUMMARY

The DEC and DEP 2013 IRPs contain limited improvements upon the companies' previous IRPs, but unfortunately, they retain most of the flaws of earlier IRPs that prevent meaningful review by the Commission and the ratepaying public. One positive development is the companies' evaluation of an "Environmental Focus Scenario" with increased levels of energy efficiency and renewable energy relative to the business-as-usual "Base Case" plan. This is the first time the companies have evaluated renewable energy as a resource rather than as an add-on strategy for compliance with the North Carolina Renewable and Efficiency Portfolio Standard.

Notwithstanding limited improvements, each company's IRP suffers from flaws that result in a "preferred plan" that is more costly, more risky, and has greater environmental impacts than would be a plan developed using robust assumptions and best practices. Key flaws in the 2013 IRPs include the following:

- DEC and DEP are planning to build too much capacity, while underinvesting in resources that would reduce system costs for all customers.
- As in prior IRPs, DEC and DEP are not planning to capture all cost-effective energy efficiency, the cheapest, cleanest resource.
- DEC and DEP do not plan to maximize cost-effective renewable energy opportunities that reduce risks to customers from rising fuel costs and anticipated regulatory requirements.
- The companies' modeling of the "Environmental Focus Scenarios" has flaws that significantly overstate costs and prevent a fair "apples-to-apples" comparison with their selected, "Base Case" plans.

To correct these flaws and minimize costs and risks to ratepayers, DEC and DEP should implement the following improvements:

- The companies should include higher levels of energy efficiency on par with those of leading utilities in their preferred "Base Case" plans, and should evaluate energy efficiency as a resource that competes on its own merits with supply-side resources.
- The companies should explicitly recognize and incorporate the benefits that renewable energy resources provide in addition to capacity and energy, including hedging against fuel cost and environmental compliance cost risks.
- DEC and DEP should each conduct, and explicitly address in their IRPs, a rigorous evaluation of the economics of continuing to operate scrubbed coal units.
- DEC should eliminate the requirement of backstand reserves for demand response, which could reduce its reserve margin and avoid the need for excess generating capacity and unnecessary costs to ratepayers.
- Each company should conduct a more complete evaluation of the risks of construction delays and cost increases associated with new nuclear generation.

DEC and DEP must cure these deficiencies to fulfill the objectives of the IRP process and provide the Commission and the ratepaying public with a complete understanding of the costs, risks and impacts of their resource plans.

II. LEGAL FRAMEWORK

N.C. Gen. Stat. § 62-110.1(c) requires the Commission to "develop, publicize, and keep current" an analysis of the State's long-range needs for electricity. In North Carolina, electric utility resource planning must result in the "the least cost mix of generation and demand-reduction measures which is achievable . . . ." N.C. Gen. Stat. § 62-2(3a). This "least cost mix" includes the "entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs." Id. As the Commission has explained,

> Integrated resource planning is an overall planning strategy which examines conservation, energy efficiency, load management, and other demand-side measures in addition to utility-owned generating plants, non-utility generation, renewable energy, and other supply-side resources in order to determine the least cost way of providing electric service. The primary purpose of integrated resource planning is to integrate both demand-side and supply-side resource planning into one comprehensive procedure that weighs the costs and benefits of all reasonably available options in order to identify those options which are most cost-effective for ratepayers consistent with the obligation to provide adequate, reliable service.

North Carolina Utilities Commission, Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina (November 7, 2012).

In furtherance of these requirements, the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires each electric utility to file a biennial report of its integrated resource planning process in even-numbered years, and in odd-numbered years, an annual report updating its most recent biennial report. As the Commission stated in its order on the 2009 IRPs, "[t]he biennial reports are to contain all required information, full and robust analyses and sensitivities, which should encompass a range of scenarios including potential regulatory changes." Order Approving Integrated Resource Plans and REPS Compliance Plans, Docket Nos. E-100, Sub 118 and E-100, Sub 124 (Aug. 10, 2010) ("2009 IRP Order") at 20.

Commission Rule R8-60 sets forth certain minimum IRP filing requirements. The rule provides, among other things, that each utility must:

- Provide a 15-year forecast of demand-side resources. Rule R8-60(c)(1).
- Conduct a "comprehensive analysis" of demand-side and supply-side resource options. Rule R8-60(c)(2) and (f).
- "[C]onsider and compare . . . both demand-side and supply side [resource] options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system." Rule R8-60(g).
- "[P]rovide the results of its overall assessment of existing and potential demand-side management programs, including a descriptive summary of each analysis performed or used by the utility in the assessment" as well as "general information on any changes to the methods and assumptions used in the assessment . . ." Rule R8-60(i)(6). The results of the assessment must include programs "evaluated but rejected" by the utility. *Id.*
- Describe and summarize "its analyses of potential resource options and combinations of resource options performed by it . . . to determine its integrated resource plan." Rule R8-60(i)(8).

III. PORTFOLIO MODELING

For their 2013 IRPs, DEC and DEP have adopted new, yet similar resource planning assumptions and methods.[1] The DEC and DEP 2013 IRPs each analyze a Base Case along with an Environmental Focus Scenario and a Joint Planning Scenario. The Environmental Focus Scenarios evaluate higher levels of energy efficiency ("EE") and renewable energy ("RE") than the Base Cases, as well as higher carbon prices and

[1] Some inconsistencies in practices and assumptions, such as the treatment of fixed costs, remain.

slightly lower fuel prices.[2] The Joint Planning Scenario shows the impact of capacity sharing between DEC and DEP.

Each company uses modeling software to develop its IRP. First, DEC and DEP utilize System Optimizer ("SO") software to identify the timing and approximate amount of new capacity needs for their systems. DEC 2013 IRP at 45; DEP 2013 IRP at 42. Second, the utilities use Planning and Risk ("PaR") software to more accurately determine the dispatch and production cost of their system. DEC 2013 IRP at 46; DEP 2013 IRP at 43. Third, DEC and DEP utilize a spreadsheet model to develop a capital cost forecast for the plans modeled in PaR and then combine capital costs with production costs from PaR, resulting in a total system cost estimate.

The result of the modeling process outlined above is presumed to be the least-cost, least-risk plan. However, in their 2013 IRPs DEC and DEP do not give full and fair consideration to cost-effective energy efficiency and renewable energy resources as alternatives to their preferred capacity expansion plans. As a result, DEC and DEP are planning to build too much capacity and are underinvesting in resources that would reduce system costs for all customers.

A. DEC and DEP Have Not Evaluated $7.7 billion in Compliance Costs Associated with Forthcoming Environmental Regulations in Their Base Case Modeling, and Are Therefore Planning to Maintain Uneconomic Coal Units in Operation.

1. <u>DEC and DEP Have Not Comprehensively Evaluated the Costs of Forthcoming Environmental Regulations.</u>

[2] As described later in these comments, the levels of renewable energy described in the 2013 IRPs do not match the capacity included in the production cost model. Also, the fuel prices used in the production cost model appear identical across the different cases.

In response to regulatory developments, persistently low natural gas prices, and recent litigation, DEC and DEP are currently in the process of retiring all of their coal-fired power plants that are not equipped with flue-gas desulfurization equipment, known as scrubbers, to control sulfur dioxide (“SO_2”) pollution. The companies plan to continue operating their “scrubbed” coal-fired units, a total of around 10,500 MW of capacity.

Even scrubbed coal units may be uneconomic to operate, however, in light of tightening environmental standards governing the inherently dirty process of burning coal for electricity. Scrubbed units face regulatory risks posed by existing, pending, and potential environmental standards, including, but not limited to, the Ozone National Ambient Air Quality Standards (“NAAQS”); 1-hour SO_2 NAAQS; Coal combustion waste (“CCW”) regulations; Clean Air Act Section 111 Greenhouse Gas New Source Performance Standards; Clean Water Act Cooling Water Intake Rule; Clean Water Act Steam Electric Effluent Limitation Guidelines; Cross State Air Pollution Rule (in the event the rule is reinstated), and Mercury and Air Toxics Standards (“MATS”). Compliance with these standards at DEC’s and DEP’s coal units will incur significant capital and operating costs, which the companies typically expect ratepayers to bear.

As in their 2012 IRPs, the companies recite and briefly consider a number of these regulatory developments in their short-term action plans and Appendix G of their respective 2013 IRPs. Each company states that its short-term action plan over the next five years includes a commitment to “[c]ontinue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as MATS, the Coal Combustion Residuals rule, the Cross-State Air Pollution Rule (CSAPR) and the new ozone National Ambient Air Quality Standard (NAAQS).” DEC 2013 IRP at 40, DEP 2013 IRP at 37-38.

Each company briefly and dismissively elaborates on environmental compliance costs and risks in Appendix G of its 2013 IRP. For example:

- MATS: Each company states that “Compliance with MATS will also require various changes to units that have had emission controls added over the last several years to meet the emission requirements of the NC [Clean Smokestacks Act].” DEC 2013 IRP at 105, DEP 2013 IRP at 99. Despite this acknowledgment, the DEC and DEP 2013 IRPs do not reflect a comprehensive study of MATS compliance alternatives, including retirement, for the vast majority of units.
- SO_2 NAAQS: Each company claims that “[t]here is no schedule for EPA to propose or finalize the rulemaking, and the outcome of the rulemaking could be different from what EPA put forth in its February 6, 2013 document.” DEC 2013 IRP at 106, DEP 2013 IRP at 100. Regulations are often subject to change, and prudent planning requires the companies to anticipate and discuss the potential costs associated with compliance with the SO_2 NAAQS.
- Coal Combustion Waste (“CCW”): Each company first recounts the devastating Tennessee Valley Authority Kingston coal ash disaster, which compelled the EPA to confront the problems of largely unregulated CCW pollution. See DEC 2013 IRP at 109, DEP 2013 IRP at 103. Each company then recites two possible outcomes of the rule—classifying

> CCW as either (1) hazardous waste under the Resource Conservation and Recovery Act's (RCRA) Subtitle C, or (2) non-hazardous waste under RCRA Subtitle D. DEC 2013 IRP at 109, DEP 2013 IRP at 103. The companies note that either proposal "will likely result in more conversions to dry ash handling, more landfills, the closing or lining of existing ash ponds and the addition of new wastewater treatment systems." Id. Despite the regulatory uncertainty cited by the companies, they acknowledge that "under either option of the proposed rule, the impact to [the Companies] is likely to be significant." Id.

These examples exemplify the companies' cursory discussion of the very real risks and costs facing coal plants, which is inadequate and inconsistent with a robust planning process.

Although they recognize that there will be costs to comply with environmental standards, DEC and DEP have not quantified those costs for specific coal units and taken them into account in their IRP modeling. In response to data requests regarding the 2012 and 2013 IRPs, DEC and DEP provided copies of assessments of the economics and other considerations related to continued operation, conversion, retirement, or life extension of certain coal-fired generating units. DEC and DEP also provided some analyses of the costs to comply with specific regulations at all affected facilities. As indicated in Table 1 below, it appears that there has been no comprehensive analysis of environmental costs at any of the DEC or DEP coal units.

Table 1: DEC and DEP Have Not Comprehensively Analyzed Environmental Control Costs

Plant	Capacity	Baghouse	ACI	Cooling	CCW	Effluent	Sources
Belews Creek 1-2 (DEC)	2,160 MW						(No studies indicating preparation of cost estimates for these units.)
GG Allen 1-5 (DEC)	1,155 MW	Yes					Confidential DEC responses to SACE request 1-6 for 2012 IRP.
JE Rogers 5-6 (DEC)	1,480 MW						(No studies indicating preparation of cost estimates for these units.)
Marshall 1-3 (DEC)	1,348 MW						(No studies indicating preparation of cost estimates for these units.)
Marshall 4 (DEC)	648 MW						(No studies indicating preparation of cost estimates for these units.)
Asheville 1-2 (DEP)	414 MW	Partial	Partial	Partial			Confidential Progress Energy Carolinas responses to SACE requests 1-7 and 1-12a for 2012 IRP.
Mayo 1 (DEP)	736 MW	Partial	Partial	Partial			
Roxboro 1-3 (DEP)	1,813 MW	Partial	Partial	Partial			
Roxboro 4 (DEP)	745 MW	Partial	Partial				

Notes:

a) DEP provided several documents in response to data requests that did not include forward-looking capital, operating, and maintenance costs associated with a retain/retire decision. (1) "2012 Regulated Subtitle D Cost Estimates" included remediation costs for eight coal stations ("Ash Basin Closure Costs Loaded"). (2) "OVERALL MACT_MATS Program Spending Overview Rev6W1 from Walt Crosmer," including capital and O&M costs associated with monitoring, trial/evaluation, and unspecified "Mercury Reduction" costs associated with a "MACT Project" at Mayo and Roxboro. (3) A presentation titled "Proposed Rule: Cooling Water Intake Structure" providing detail regarding compliance strategy, but no cost forecasts. Progress Energy Carolinas responses to SACE request 1-12a for 2012 IRP.

b) DEP provided several spreadsheets related to Robinson and Cape Fear compliance costs. (PEC 1-7 2012 response, workbooks not titled.)

c) DEP provided Electric Power Research Institute, "Closed-Cycle Cooling System Retrofit Study: Capital and Performance Cost Estimates," 2011 Technical Report (January 2011). CAVT does not rely on this study, but instead draws cost assumptions from U.S. Environmental Protection Agency, "Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule," (2011).

2. If DEC and DEP Operate Their Coal Units As Planned, Customers Are at Risk for Nearly $8 billion in Additional Costs.

As discussed above, although the companies acknowledge "significant" costs due to forthcoming environmental regulations, their IRP analyses essentially assume zero costs. An analysis of publicly available data, coupled with data supplied by Duke Energy, shows that in fact, DEC and DEP will need to make billions of dollars in additional capital investments to continue operating their "scrubbed" coal units. Synapse Energy Economics ("Synapse") recently created the Coal Asset Valuation Tool ("CAVT" v.4.25), a database estimating prospective capital and operating expenditures for environmental compliance at coal-fired power plants across the country.[3] Using publicly available cost data and methodologies, CAVT calculates the cost of complying with environmental regulations under various regulatory scenarios through 2042.[4] The environmental compliance costs incorporated in the CAVT model include those for flue gas desulfurization ("FGD");[5] Selective Catalytic Reduction ("SCR");[6] fabric filter baghouses;[7] Activated Carbon Injection (ACI);[8] cooling water intake structures;[9]; Coal Combustion Waste;[10] effluent limitation guidelines;[11] and a carbon price.[12]

[3] Synapse Energy Economics, Inc., *Forecasting Coal Unit Competitiveness: Coal Retirement Assessment Using Synapse's Coal Asset Valuation Tool (CAVT)* (October 2013); Synapse Energy Economics, Inc., *Coal Asset Valuation Tool v. 4.25* (April 2014).

[4] The CAVT database aggregates publicly available data and cost methodologies from the U.S. Environmental Protection Agency, Sargent & Lundy, the Electric Power Research Institute, and the Edison Electric Institute.

[5] CAVT medium scenario assumes installation by 2025, but all Duke Energy coal plants already have FGDs or an equivalent technology so no FGD costs are included in CAVT output.

[6] CAVT medium scenario assumes installation by 2019, but all Duke Energy coal plants already have SCRs or an equivalent technology so no SCR costs are included in CAVT output.

[7] CAVT assumes installation by 2018. Duke Energy's existing environmental control costs specified in its IRP financial models includes operating costs associated with electrostatic precipitators (ESPs). ESPs would likely be removed if baghouses were installed. However, ESP operating cost savings (which are confidential data) would have a negligible effect relative to the cost to install and operate baghouses. CAVT costs are from Sargent & Lundy, *IPM Model – Updates to Cost and Performance for APC*

Using CAVT, it appears that DEC and DEP have failed to include about ***$7.7 billion*** in environmental compliance costs—about $5.5 billion in capital costs and $2.2 billion in operating costs–that would be incurred if the companies continue to operate their coal units. These environmental compliance costs would be recovered from customers through 2042. As illustrated in Table 2, below, the present value of environmental compliance costs at individual units averages $732 per kW, and ranges from $363 per kW at DEC's J.E. Rogers (formerly Cliffside) Unit 6 to $1,364 per kW at DEP's Asheville Unit 2.

Technologies: Mercury Control Cost Development Methodology, report to US Environmental Protection Agency (March 2013).

[8] CAVT medium scenario controls assumed for installation in 2016. CAVT costs are from Sargent & Lundy, *IPM Model – Updates to Cost and Performance for APC Technologies: Particulate Control Cost Development Methodology,* report to US Environmental Protection Agency (March 2013).

[9] CAVT medium scenario control assumptions, such as impingement or wet cooling towers, vary based on unit characteristics and are assumed to be installed in 2019. CAVT costs are from U.S. Environmental Protection Agency, *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule,* EPA-821-R-11-001 (March 2011).

[10] CAVT medium scenario control assumptions based on non-hazardous "Subtitle D" controls installed in 2019. CAVT costs are from Electric Power Research Institute (EPRI), *Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act* (November 2010). (Note that the EPRI report also includes costs for Subtitle D, the report title notwithstanding.) CAVT costs also referenced to Edison Electric Institute, *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*, prepared by ICF International (January 2011).

[11] CAVT medium scenario control assumptions based on EPA "option 3" installed in 2019, requiring chemical precipitation, biological treatment, and zero-discharge dry handling for certain wastewater. CAVT costs are from U.S. Environmental Protection Agency, *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category,* EPA-821-R-13-002 (April 2013).

[12] Duke Energy's IRP analysis assumes a carbon price, so no carbon costs are included in CAVT output.

Table 2: CAVT Forecast of Operating and Environmental Control Costs, 2013-42

Coal Unit	Operating Costs, Current Controls ($/MWh fuel + VOM)	Environmental Control Costs (Capital, Fixed O&M, Variable O&M)		
		PV ($ million)	Energy ($ / MWh)	Capacity ($ / kW)
Belews Creek 1 (DEC)	41.18	758	5.69	702
Belews Creek 2 (DEC)	41.16	743	6.46	688
GG Allen 1 (DEC)	50.64	171	25.72	1,038
GG Allen 2 (DEC)	50.67	170	29.77	1,029
GG Allen 3 (DEC)	50.82	249	14.40	907
GG Allen 4 (DEC)	50.81	252	12.93	917
GG Allen 5 (DEC)	50.67	246	16.63	896
JE Rogers 5 (DEC)	47.97	377	10.79	660
JE Rogers 6 (DEC)	50.72	330	2.76	363
Marshall 1 (DEC)	43.95	286	11.63	818
Marshall 2 (DEC)	43.93	311	11.22	888
Marshall 3 (DEC)	43.79	494	7.73	763
Marshall 4 (DEC)	44.18	503	7.08	775
Asheville 1 (DEP)	48.77	278	16.42	1,347
Asheville 2 (DEP)	48.80	282	17.74	1,364
Mayo 1 (DEP)	49.54	586	8.83	796
Roxboro 1 (DEP)	45.55	292	8.12	711
Roxboro 2 (DEP)	45.55	409	6.92	622
Roxboro 3 (DEP)	45.56	478	7.09	642
Roxboro 4 (DEP)	45.51	473	6.85	635
DEC Subtotal	$ 45.02	$ 4,891	$ 7.48	$ 720
DEP Subtotal	$ 46.66	$ 2,798	$ 8.46	$ 755
Duke Energy Total	**$ 45.57**	**$ 7,690**	**$ 7.81**	**$ 732**

Source: Synapse Coal Asset Valuation Tool (v. 4.25), assuming "medium" scenario without CO_2 costs. Fixed O&M, which represent about 16% of the CAVT estimate of production costs for Duke Energy's fleet, are not included in "Operating Costs" as summarized here.

Based on a review of responses to data requests provided by DEC or DEP, the cost estimates in Synapse's CAVT model appear to be reasonable, even conservative. DEC and DEP did provide some environmental cost forecasts, as summarized in Table 1. Although there are some differences, on balance, the costs included in CAVT appear to be generally consistent with the costs estimated by DEC and DEP. The CAVT costs demonstrate the magnitude of the costs that DEC and DEP are likely to incur in order to maintain these coal units in operation as planned in their IRPs. DEC and DEP should develop their own cost estimates for use in modeling for their 2014 IRPs, and should also include in the 2014 IRPs a detailed discussion of the results of their modeling.

As illustrated in Table 3, below, the CAVT environmental compliance cost data suggest that DEC and DEP have omitted significant future control costs associated with major forthcoming environmental regulations. The largest share of these costs is from baghouses and CCW handling and disposal, which account for about two-thirds of the projected $7.7 billion in capital, operating, and maintenance costs through 2042.[13] These costs are generally omitted from the IRP analysis, however. Moreover, for some coal units, fixed costs that Duke is currently incurring were also omitted from model inputs. Because these capital, fixed, and variable costs are not factored into the resource plan, the DEC and DEP 2013 IRPs fail to demonstrate if it would be more economic for the company to continue operating existing coal plants or invest in alternatives.

[13] According to the data sources used in CAVT, baghouse installation costs are typically on the order of $100 million per unit, and mid-range estimates for coal combustion waste compliance costs are on the order of $75 million per facility.

Table 3: Environmental Controls Included in CAVT Financial Analysis for Duke Energy with Applicable Regulations[14]

Regulation	Baghouse	ACI	Cooling	CCW[15]	Effluent	Total
Ozone NAAQS						
Coal Combustion Waste Regulations				X		
Clean Water Act Cooling Water Intake Rule			X			
Clean Water Act Steam Electric Effluent Limitation Guidelines					X	
Cross State Air Pollution Rule (if reinstated)	X					
Mercury and Air Toxics Standard ("MATS")	X	X				
DEC Compliance Cost	$ 1,889	$ 658	$ 606	$ 1,346	$ 392	**$ 4,891**
DEP Compliance Cost	$ 1,260	$ 366	$ 67	$ 811	$ 294	**$ 2,798**
Total, 2013-42 (NPV $ million)	**$ 3,149**	**$ 1,024**	**$ 673**	**$ 2,157**	**$ 687**	**$ 7,690**

Source: Synapse Coal Asset Valuation Tool (v. 4.25), assuming "medium" scenario without CO_2 costs. See footnote **Error! Bookmark not defined.** for sources of data used to develop these estimates.

[14] Carbon-related costs are not considered since DEC and DEP included these costs in their resource planning models. Controls related to compliance with 1-hour Sulfur Dioxide NAAQS (e.g., FGD) have been installed at all DEC and DEP units, and are thus excluded from this table.

[15] The "medium" scenario developed by Synapse assumes that CCW regulations will designate coal ash as nonhazardous, consistent with the anticipated outcome described by Keith Trent, EVP and COO, Regulated Utilities, for Duke Energy. Duke Energy, Transcript of Q4 2013 Duke Energy Corporation Earnings Conference call (February 18, 2014), p. 20.

DEC and DEP did not dispute that they have not factored the cost of compliance with forthcoming environmental regulations into the resource planning process. In fact, they have acknowledged that the "capital cost associated with future environmental control requirements were not considered in the filing of the 2013 IRP."[16] In defense of this decision to omit these enormous potential costs from the IRP analysis, the utilities go so far as to assert that "it would have been ***imprudent*** to include large capital costs for compliance" in their IRPs.[17]

Contrary to their assertion that it would be "imprudent" to plan in advance to avoid, rather than incur, environmental compliance (or cleanup) costs, it is DEC's and DEP's exclusion of environmental costs from the IRP economic modeling that is imprudent. The IRPs filed with state regulators stand in stark contrast to statements made to financial analysts, in which Duke Energy acknowledges billions of dollars in looming environmental costs. In its most recent "Earnings Review and Business Update," Duke Energy estimated $2.9 billion in environmental expenditures (or "investments") in the Carolinas for 2014-2023, including $375 million for DEC and $650 million for DEP for 2014-18.[18] None of these capital costs were evaluated in the 2013 IRP economic models.

Despite its failure to plan for the costs of environmental compliance—or better yet, plan to avoid them-- Duke Energy expects that the customers of its Carolinas operating utilities will bear these costs. During a recent call with financial analysts, Duke Energy CEO Lynn Good stated that the company's estimated environmental compliance expenditures included the costs of ash pond closures and conversion to dry handling, and touted the "good history of

[16] Duke Energy, Response to SACE DR 2-5.
[17] Duke Energy Response to Comments by SACE, CCL and Upstate Forever on 2013 Integrated Resource Plan, SC PSC Docket No. 2013-8-E and 2013-10-E (March 12, 2014) ("SC Response to Comments") p. 2. (emphasis added).
[18] Duke Energy, "Earnings Review and Business Update: Fourth Quarter 2013" (February 18, 2014) p. 47, 51.

environmental recovery" in the Carolinas.[19] In its financial planning, Duke Energy appears to be banking on incurring these environmental costs and recovering them from customers.

To suggest that including future environmental compliance costs in resource planning would be "imprudent" flies in the face of prudent resource planning, which after all is intended to minimize the long-run cost to customers of producing electricity. Prudent resource planning should include the costs of complying with foreseeable environmental regulations and the costs of ensuring that customers will not pay for avoidable environmental disasters.

3. Considering a Comprehensive Forecast of Coal Unit Compliance Costs, DEC and DEP Should Reconsider Decisions to Retain Coal Units.

Duke Energy's planning process is headed in the direction of overcharging customers. By failing to model environmental compliance costs in their IRP analyses (with the exception of carbon-related costs), DEC and DEP are putting their customers on the hook for these costs. The cumulative compliance costs will not be known until the companies seek to recover them in general rate cases—and even worse, if each individual compliance cost is considered independently of the others, the cumulative investments in some units may exceed the actual value of those units to the system.

DEC's resistance to incorporating the cost of compliance with forthcoming environmental regulations is not new. In the proceeding on the 2010 IRPs, in response to comments by SACE that its IRP failed to evaluate the economics of continuing to operate its coal plants, DEC stated that, "To the extent such resources become less economic to operate … [DEC] will make all necessary adjustments to ensure that its generation system is being planned,

[19] Duke Energy, Transcript of Q4 2013 Duke Energy Corporation Earnings Conference call (February 18, 2014), p. 18-19.

constructed and operated at the least reasonable cost to its customers."[20] Even without considering the CAVT cost estimates, Duke Energy now has ample data that its coal resources have become "less economic to operate." Contrary to DEC's expectations just three years ago, the economics of its coal fleet are not improving, but in fact continuing to erode.

While in 2011, DEC argued that its current coal fleet includes some of the most economic units on the system, as evidenced by the high capacity factor projections in the 2010 IRP,"[21] the 2013 IRPs indicate that many of the plants that have not yet been retired are now forecast to have low capacity factors. Under the DEC and DEP Base Cases, the capacity factor of the utilities' combined coal fleet is projected to [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL], averaging [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] over the [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] time period, as illustrated in Figure #, below. Ten units representing a combined capacity of about 4,300 MW, including Allen 1-5, JE Rogers 5, Marshall 1, Mayo 1, and Roxboro 3-4, are forecast to operate generally at capacity factors of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] beginning in [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL]. The remaining 10 units, representing about 6,200 MW, are forecast to average operating at a capacity factor [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] during that time period, with only Asheville 1-2 and J.E. Rogers 6 forecast to often exceed a [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] capacity factor. In the Environmental Focus Scenarios, the forecast capacity factor averages [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] than in the Base Cases, with most of the [BEGIN

[20] Duke Energy Carolinas, Reply Comments, NCUC Docket No. E-100, Sub 128 (March 1, 2011), p. 27.
[21] Duke Energy Carolinas, Reply Comments, NCUC Docket No. E-100, Sub 128 (March 1, 2011), p. 27.

CONFIDENTIAL END CONFIDENTIAL], as illustrated in Figure1, below. Beginning in [BEGIN CONFIDENTIAL END CONFIDENTIAL], in addition to the 10 units just mentioned, Marshall 2 is forecast to operate at a typical capacity factor of [BEGIN CONFIDENTIAL END CONFIDENTIAL]. The capacity factors forecast for Asheville 1-2 and JE Rogers 6 generally [BEGIN CONFIDENTIAL END CONFIDENTIAL].

Figure 1: Forecast Capacity Factor, Duke Energy Coal Fleet [BEGIN CONFIDENTIAL

END CONFIDENTIAL] Source: Duke Energy response to SACE DR 2-10.

As the average capacity factor of Duke Energy's Carolinas coal fleet is forecast to [BEGIN CONFIDENTIAL END CONFIDENTIAL], the costs associated with forthcoming environmental regulations will result in a revenue requirement that is spread across [BEGIN CONFIDENTIAL END CONFIDENTIAL] generation. This will, in turn, make these units [BEGIN CONFIDENTIAL END CONFIDENTIAL] to dispatch.

Assuming dispatch as forecast in Duke Energy's Base Case will [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] the average levelized revenue requirement associated with its coal fleet by [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL], expressed on an energy basis (per megawatt-hour or "MWh"). Thus, rather than costing [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] utilizing the CAVT historical capacity factor assumption, the cost of environmental controls at Duke Energy's forecast average capacity factor results in a revenue requirement of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL].

As noted above, DEC and DEP's IRPs lack sufficient information to determine whether each coal unit is more economical to continue operating (after investing in environmental controls), or to replace with alternatives. However, the CAVT estimates of the costs to invest in environmental upgrades can be benchmarked against industry cost estimates to determine whether continued operation of each unit or an alternative will be more economical. Two common benchmarks for the cost of new capacity are natural gas combustion turbine (peaking) and natural gas combined cycle (intermediate/baseload) gas units. According to the most recent Energy Information Administration cost estimates, the total overnight cost of capacity in 2012 dollars is $673 per kW for a combustion turbine unit and $1,022 per kW for a combined cycle unit.[22]

The 20 coal units currently planned for long-term operation by DEC and DEP can be placed in four groups based on the CAVT estimates of environmental compliance costs and the units' forecast operating characteristics, which we designate Groups A-D:

[22] Energy Information Administration, *Annual Energy Outlook 2014*, Early Release Electricity Market Module, Table 8.2 (January 2014).

Group A includes about 4,650 MW at 11 units (Allen 1-5, J.E. Rogers 5, Marshall 1-2, Mayo 1, and Roxboro 3-4) whose capacity factors [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] in the Environmental Focus Scenario. Because these eleven units are forecast by Duke Energy to transition to [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] capacity factors, their [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] will be more comparable to gas peaking units than to intermediate or baseload units. According to the cost estimates from CAVT, the cost to build and operate environmental controls at these units over the 2014-42 timeframe ranges from $635 to $1,038 per kW, which is similar to or more than the current estimated $673 per kW cost of gas combustion turbine unit capacity. Applying the capacity factors from DEC and DEP's IRP models, updating these 11 units will cost [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL]. In fact, environmental controls at each of [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] will actually cost [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] per MWh [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL].

Group B includes 2,800 MW at four units (Belews Creek 2, Marshall 4, and Roxboro 1-2) whose capacity factors are forecast by Duke Energy to be generally between [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] beginning about 2023. According to the cost estimates from CAVT, the cost to build and operate environmental controls at these units over the 2014-42 timeframe ranges from $622 to $775 per kW, which is similar to the cost of gas combustion turbine unit capacity but less than that of combined cycle unit capacity. Applying the capacity factors from DEC and DEP's IRP models, these four units will cost [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] to update.

Group C includes 2,640 MW at three units (Belews Creek 1, Marshall 3, and J.E. Rogers 6) whose capacity factors are forecast by Duke Energy to [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] after 2023 to generally between [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL]. According to the cost estimates from CAVT, the cost to build and operate environmental controls at these units over the 2014-42 timeframe ranges from $363 to $763 per kW, which is less than the cost of combined cycle capacity. Applying the capacity factors from DEC and DEP's IRP models, these three units will cost [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] to update.

Group D includes about 415 MW at two units (Asheville 1-2) whose capacity factors are forecast by Duke Energy to be similar to those in Group C. For those two units, however, the cost to build and operate environmental controls over the 2014-42 timeframe is over $1,300 per kW, substantially more than the cost of combined cycle capacity. Again applying the capacity factors from DEC and DEP's IRP models, these two units will cost [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] to update.

Table 4: Forecast of Operating and Environmental Control Costs Using Duke Energy Forecast of Capacity Factors, 2013-42

Coal Unit	**Unit Capacity** (MW)	**Operating Costs, Current Controls** ($/MWh fuel + VOM)	**Environmental Control Costs** (Capital, Fixed O&M, Variable O&M)				
			Assuming CAVT Historical Capacity Factor		**Assuming Duke Energy Forecast Capacity Factor [**BEGIN CONFIDENTIAL		**Difference in Energy Cost** (Percent Increase) [CONFIDENTIAL]
			Capacity Factor	**Energy Cost** ($ / MWh)	**Capacity Factor**	**Energy Cost** ($ / MWh)	
Belews Creek 1 (DEC)	1,080	41.18	84%	5.69	[redacted]	[redacted]	[redacted]
Belews Creek 2 (DEC)	1,080	41.16	73%	6.46	[redacted]	[redacted]	[redacted]
GG Allen 1 (DEC)	165	50.64	28%	25.72	[redacted]	[redacted]	[redacted]
GG Allen 2 (DEC)	165	50.67	24%	29.77	[redacted]	[redacted]	[redacted]
GG Allen 3 (DEC)	275	50.82	43%	14.40	[redacted]	[redacted]	[redacted]
GG Allen 4 (DEC)	275	50.81	49%	12.93	[redacted]	[redacted]	[redacted]
GG Allen 5 (DEC)	275	50.67	37%	16.63	[redacted]	[redacted]	[redacted]
JE Rogers 5 (DEC)	571	47.97	42%	10.79	[redacted]	[redacted]	[redacted]
JE Rogers 6 (DEC)	910	50.72	90%[23]	2.76	[redacted]	[redacted]	[redacted]
Marshall 1 (DEC)	350	43.95	48%	11.63	[redacted]	[redacted]	[redacted]
Marshall 2 (DEC)	350	43.93	54%	11.22	[redacted]	[redacted]	[redacted]
Marshall 3 (DEC)	648	43.79	68%	7.73	[redacted]	[redacted]	[redacted]
Marshall 4 (DEC)	648	44.18	75%	7.08	[redacted]	[redacted]	[redacted]
Asheville 1 (DEP)	207	48.77	56%	16.42	[redacted]	[redacted]	[redacted]
Asheville 2 (DEP)	207	48.80	53%	17.74	[redacted]	[redacted]	[redacted]
Mayo 1 (DEP)	736	49.54	62%	8.83	[redacted]	[redacted]	[redacted]
Roxboro 1 (DEP)	411	45.55	60%	8.12	[redacted]	[redacted]	[redacted]
Roxboro 2 (DEP)	657	45.55	62%	6.92	[redacted]	[redacted]	[redacted]
Roxboro 3 (DEP)	745	45.56	62%	7.09	[redacted]	[redacted]	[redacted]
Roxboro 4 (DEP)	745	45.51	63%	6.85	[redacted]	[redacted]	[redacted]

[23] Due to its recent in-service date, CAVT did not have a historical basis for assuming a capacity factor. In order to present the plant's forward-going costs in the most favorable light, a 90% capacity factor was selected, understanding that it likely exceeds the unit's future utilization rate.

DEC Subtotal	6,792	$ 45.02	66%	$ 7.48		[redacted]			[redacted]			[redacted]	
DEP Subtotal	3,708	$ 46.66	61%	$ 8.46		[redacted]			[redacted]			[redacted]	
Duke Energy Total	**10,499**	**$ 45.57**	**64%**	**$ 7.81**		[redacted]			[redacted]			[redacted]	

END CONFIDENTIAL]

Source: Synapse Coal Asset Valuation Tool (v. 4.25), assuming “medium” scenario without CO_2 costs.

Using simple capacity cost benchmarks, it appears fairly certain that the long-run capital and operating costs of necessary environmental upgrades will make it uneconomic to invest in required environmental controls for over 5,000 MW—roughly 50% of DEC and DEP's remaining coal capacity—including the following units:

- Allen 1-5, Cliffside 5, Marshall 1-2, Mayo 1, and Roxboro 3-4: As discussed above, the 4,650 MW of capacity (Group A) at these 11 units will be more expensive to maintain than to replace with a new peaking gas unit.
- Asheville 1-2: As discussed above, the 415 MW of capacity (Group D) at these two units will be more expensive to maintain than to replace with a combined cycle gas unit.

Building and operating environmental controls at these 13 units will cost customers about $3.5 billion, which is highly likely to exceed the cost of alternatives, including energy efficiency and renewable energy, which DEC and DEP have not evaluated in a head-to-head comparison with decisions to continue operating these facilities. Whether or not any of the other seven units are cost-effective to upgrade is less clear using simple benchmarks. Only with a comprehensive, accurate assessment of the economic viability of Duke Energy's Carolinas coal fleet will it be possible to determine precisely which units should be retired.

Because DEC and DEP did not include accurate cost inputs regarding these costs in their expansion planning models, DEC and DEP are imprudently proceeding with the assumption that these coal units will continue to operate for the next 15 years, and implicitly assuming that any required investments are cost-effective enough to not affect their short-term action plans. Our analysis strongly suggests that retirement of a minimum 5,000 MW of coal capacity is likely to be the most cost-effective solution. The question should be not whether additional coal capacity should be slated for retirement, but how much and when.

DEC and DEP should each conduct a rigorous assessment of the costs to comply with all current and imminent regulations, and whether those costs render their existing coal units uneconomical. To the extent they have not conducted such an assessment, they should do so, and discuss it in their IRPs. We recommend that the Commission order DEC and DEP to comprehensively evaluate the costs of compliance with forthcoming environmental regulations, including appropriate "lenient" and "strict" sensitivities, in the 2014 IRPs. Further, as discussed elsewhere in our comments, neither energy efficiency nor renewable energy were allowed to compete with natural gas or coal plants in the IRP modeling. Rigorous analysis of the economics of operating scrubbed coal units should be coupled with consideration of whether clean energy resources such as energy efficiency and renewable energy could assist in lowering the overall cost to customers of compliance with environmental regulations.

B. DEC and DEP Have Not Fairly Evaluated Energy Efficiency and Renewable Energy in Their Base Case Modeling, and Are Therefore Planning T11qo Build Excess Capacity.

Unreasonable planning assumptions and methods used to develop the IRPs resulted in Base Case plans with excess generating capacity. DEC's and DEP's Base Cases result in the wrong balance of system resources because they rely on planning assumptions and methods that unreasonably restrict the evaluation of energy efficiency and renewable energy resources. As in prior IRPs, DEC and DEP are not planning to capture all cost-effective energy efficiency, the cheapest, cleanest resource. Nor do DEC and DEP plan to maximize cost-effective RE opportunities that could reduce risks to customers from variable fuel costs and other factors. Furthermore, the load forecasts used in the IRPs may not reflect the companies' own realistic expectations for growth. If DEC and DEP incorporate all cost-effective energy efficiency and renewable energy into their IRPs, as well as realistic load forecasts, they can defer or avoid planned new generation—and the costs and risks that it represents for customers.

1. DEC and DEP's modeling uses flawed assumptions about the cost of energy efficiency.

DEC and DEP's efficiency cost projections are excessive and flawed, for several reasons.[24] First, DEC's long-term energy efficiency cost projection, beginning in 2018 for the Base Case and in 2014 for the Environmental Focus Scenario relies on total resource costs instead of utility costs. DEC's cost projections are based on the measure costs included in its potential study that relied on total resource costs, which include costs incurred by the customer.[25] However, because DEC uses its energy efficiency cost forecast as part of its revenue requirement estimate, DEC should only include utility costs—those costs that are incurred by the utility and passed through to customers. For example, if DEC offered customers a 25% incentive to install LED exit signs, then only $250 of every $1,000 spent on the signs would be reimbursed by the utility and thus part

[24] DEC and DEP did not align their respective long-term forecasts for the cost of energy efficiency programs for the 2013 IRPs. DEP's forecasting method, while more reasonable than the method used by DEC, appears to be a placeholder and not likely to be retained for future IRPs. Accordingly, these comments focus on the method used for DEC's long-term projection of efficiency costs, as described in response to a data request, SACE DR 2-13.

[25] Forefront Economics Inc. and H. Gil Peach & Associates LLC, *Duke Energy Carolinas: Market Assessment and Action Plan for Electric DSM Programs North Carolina* (February 2012), p. 28. NCUC Docket E7 Sub 1032.

of the revenue requirement. However, DEC's long-term cost forecast in this example would include the full $1,000 in the cost of the measure, thus counting in the revenue requirement the costs that are spent by the customer. Because DEC's 2013 IRP utilizes total resource costs rather than utility costs in its long-term efficiency forecast, DEC's levelized cost of energy efficiency increases from about 2 cents per kWh in 2013 to about 37 cents per kWh in 2032.[26]

With the limited information provided by DEC, it is impossible to quantify what the utility share of the total resource cost should be. Furthermore, the answer to this question depends on the design of DEC's programs and would likely change over time to the degree that DEC successfully educates consumers and achieves market transformation, thus reducing the need for financial incentives.

DEC used four other flawed assumptions and methods in its projection of long-term energy efficiency program costs further distort the future cost of efficiency. These flaws are rooted in a misuse of certain assumptions in DEC's energy efficiency market potential study, which according to its authors, "is expected to help inform utility planners regarding the extent of DSM opportunities and to provide broadly defined approaches for acquiring savings *over the short term*."[27]

First, DEC assumes that each specific measure reaches 60% market saturation and no more.[28] This means that for a more aggressive energy efficiency program, rather than

[26] Duke Energy response to SACE DR 2-13.
[27] Forefront Economics Inc. and H. Gil Peach & Associates LLC, *Duke Energy Carolinas: Market Assessment and Action Plan for Electric DSM Programs North Carolina* (February 2012), NCUC Docket E7 Sub 1032, p. 1 (emphasis added).
[28] Duke Energy response to SACE DR 2-13.

lower-cost measures achieving a higher market saturation, the program shifts to higher-cost measures.

Second, the potential study is based on measures available in 2012, with no provision for the introduction of new energy efficient technology through 2028 or reduction in costs for technologies available in 2012.[29] It is very unlikely that innovation to achieve energy efficiency will come to a complete stop. While this assumption may be reasonable for some planning purposes, it is not a reasonable basis for assuming extraordinarily high program costs beginning in 2019.

Third, the market potential study indicates that "the marginal cost of acquiring additional customers into a program rises as more and more customers from the target customer segment are treated by the program."[30] In fact, economies of scale serve to reduce program costs per kWh saved: as utility programs scale up to higher levels of market penetration, every dollar in program costs can achieve more savings.[31] DEC's short-term program cost forecasts, which show overhead (administrative and "other" costs) declining from 20% to 10% of program costs, underscore this principle.[32]

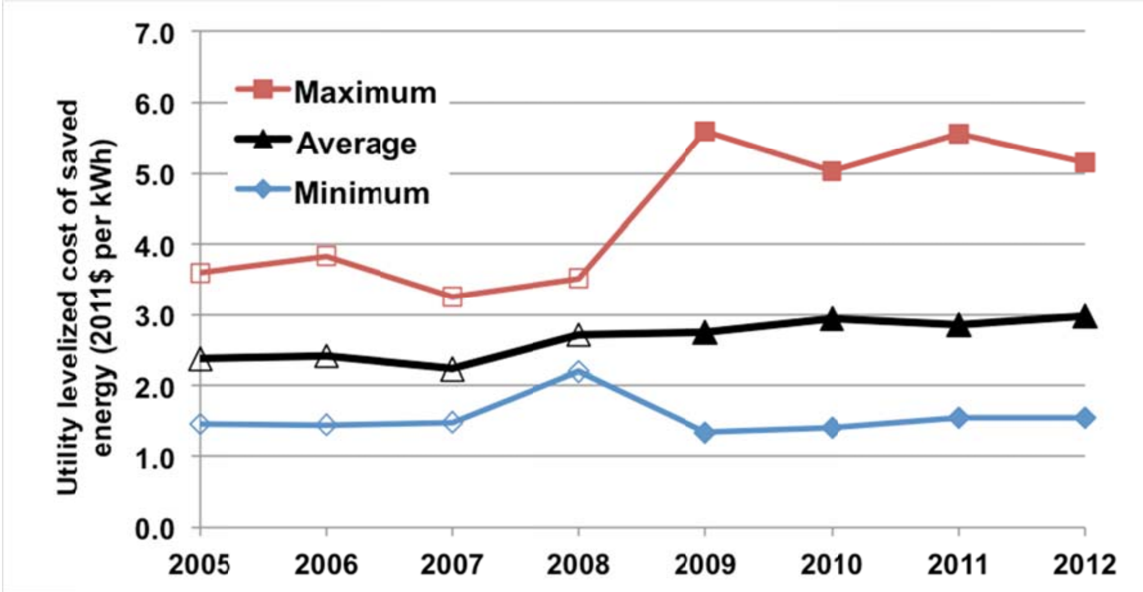
Fourth, and finally, DEC assumes a 30% program cost overhead based on a rough estimate discussed in the potential study.[33] The rough estimate is approximately double the average program overhead cost included in DEC's short-term cost projection.

[29] Duke Energy response to SACE DR 2-13.
[30] Forefront Economics Inc. and H. Gil Peach & Associates LLC, *Duke Energy Carolinas: Market Assessment and Action Plan for Electric DSM Programs North Carolina* (February 2012), p. 34. NCUC Docket E7 Sub 1032
[31] Takahashi, K and D Nichols, *The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date,* 2008 ACEEE Summer Conference, August 2008.
[32] Duke Energy response to SACE DR 1-19.
[33] Duke Energy response to SACE DR 2-13.

Examples of other long-running efficiency programs do not support DEC's long-term cost assumptions. DEC's projection of a 190% increase (adjusted for inflation) in the cost of energy efficiency over the first decade of the Environmental Focus Scenario is at odds with the experience of well-established, long-running energy efficiency programs. For example, Energy Trust of Oregon has tracked Oregon's energy efficiency program costs using a consistent method for over a decade, and found that those costs have increased by only about 25% over a decade, most of which occurred during a single year of program expansion.[34] Moreover, the American Council for an Energy-Efficient Economy (ACEEE) recently published a nationwide, eight-year trend of utility energy efficiency program costs, which suggests that average national energy efficiency program costs have increased by roughly 25% (adjusted for inflation) as illustrated in Figure 2, below.

[34] Energy Trust of Oregon, "Briefing Paper: Energy Trust of Oregon Energy Efficiency Programs" (June 2013), p 22. According to Ted Light at ETO, the roughly 50% increase in levelized energy efficiency program costs are nominal costs; adjusting for inflation, the ten-year trend represents a roughly 25% increase in costs.

Figure 2: Levelized Cost of Energy Efficiency Programs (Nationwide, by ACEEE) [35]



ACEEE also analyzed whether increasing the scale of energy efficiency programs results in higher average costs. The study found a "low or weak correlation between [the cost of saved energy] and electricity savings as a percentage of sales," and goes on to conclude that utility energy efficiency programs "… are exceeding 1% or 1.5% savings as a percentage of sales while maintaining a cost-effective portfolio."[36] Thus, even after many years of offering energy efficiency programs, the cost to offer energy efficiency programs increases very slowly, as shown by the ACEEE and Oregon data. Yet under DEC's Environmental Focus Scenario, costs increase from roughly 2 to 7 cents per kWh levelized over the first decade, double the escalation rate indicated in the ACEEE study.[37]

---

[35] Maggie Molina, *The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs*, American Council for an Energy-Efficient Economy Report U1402 (March 2014), p. 37.
[36] Maggie Molina, *The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs*, American Council for an Energy-Efficient Economy Report U1402 (March 2014), p. 30.
[37] Duke Energy response to SACE DR 2-13.

A recent nationwide forecast of the cost of saved energy by Lawrence Berkeley National Laboratory ("LBNL"), like the ACEEE study, reached a very different conclusion about long-term costs than that reached by DEC.[38] LBNL estimated that nominal energy efficiency program spending costs would increase at an annual rate of 1.78% for North and South Carolina.[39] We applied Duke's inflation rate and the 1.78% annual escalation factor from LBNL (adjusted to also include inflation) to Duke's short-term (five-year) costs of the Base Case programs and the additional Environmental Focus Case programs to create a long-term program cost forecast. The differences between projected program costs using the LBNL escalation rate and the costs projected by Duke Energy are substantial, as summarized in Table 5 and illustrated in Figure 3, both below. The cost differences are particularly large in DEC's Environmental Focus Scenario, where application of the LBNL escalation rate reduces the projected revenue requirement associated with DEC's energy efficiency program costs from $3.4 billion to $2.1 billion.

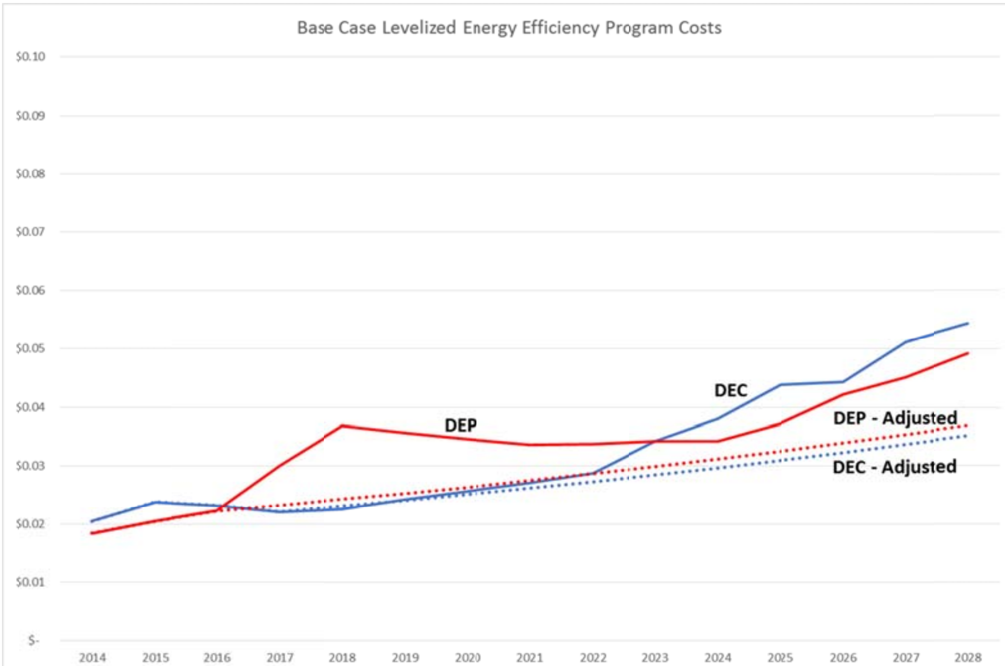
Table 5: Comparison of Energy Efficiency Program Cost Projections[40]

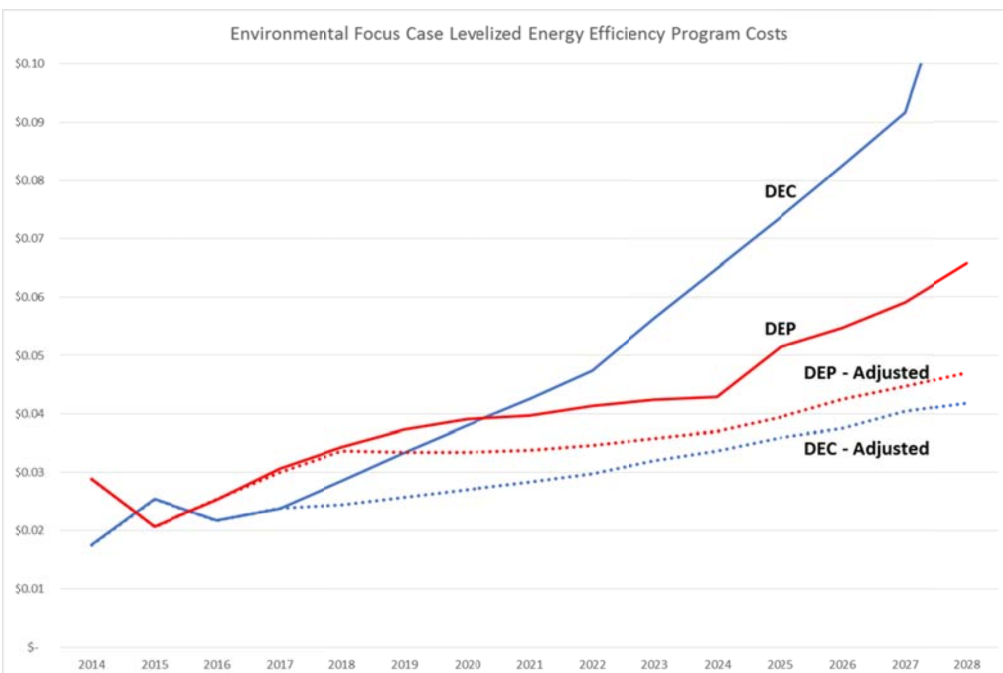
	Duke Energy Carolinas		**Duke Energy Progress**	
	Company Forecast	**Inflation + LBNL Rate**	**Company Forecast**	**Inflation + LBNL Rate**
2028 Levelized Energy Efficiency Program Costs (cents per kWh)				
Base Case	5.4	3.5	4.9	3.7
Environmental Focus Scenario	12.5	4.2	6.6	4.7
2014-28 Revenue Requirement ($billions, net present value)				
Base Case	1.5	1.3	0.7	0.6
Environmental Focus	3.4	2.1	1.7	1.5

[38] Galen L. Barbose et al., *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025*, LBNL-5803E (January 2013).
[39] Galen L. Barbose et al., *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025*, LBNL-5803E (January 2013).
[40] Duke Energy data calculated from data provided in response to SACE DR 2-13.

Scenario				

Figure 3: Adjustment of Energy Efficiency Program Costs Escalation to Inflation[41]





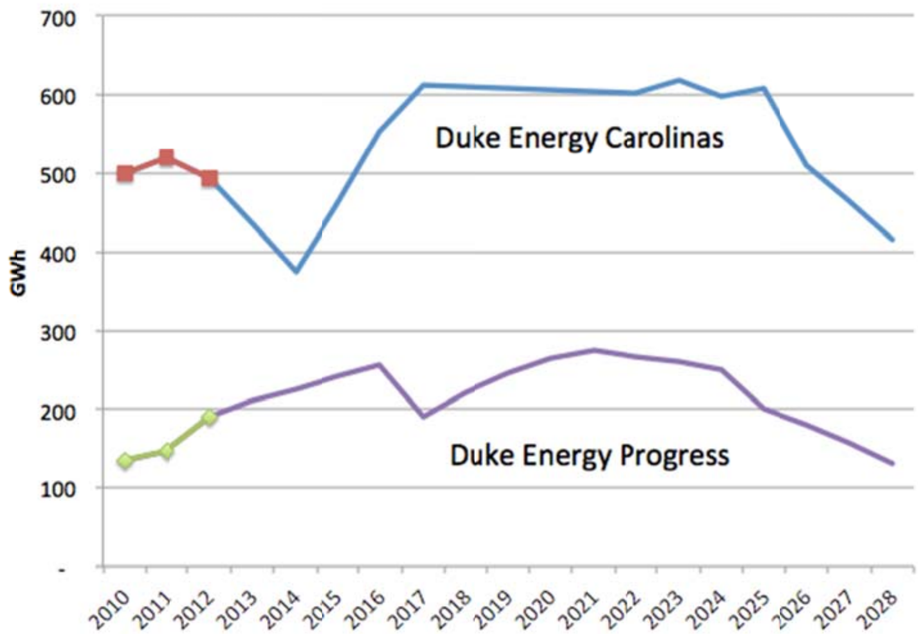
[41] Program Costs Expressed as $ per kWh saved. Levelization assumes a 10-year measure life.

In summary, the Commission should not rely on Duke Energy's long-term program cost forecasts, particularly when evaluating the Environmental Focus Scenario. As summarized in Table 5 above, rather than the $5.1 billion estimated by DEC and DEP, a more reasonable forecast of energy efficiency program costs in the Environmental Focus Scenario is about $3.6 billion, including $2.1 billion for DEC and $1.5 billion for DEP.

2. <u>DEC and DEP's modeling of efficiency is inadequate because they do not plan for growth of the efficiency resource.</u>

DEC's actual energy savings impacts are higher than the projected EE/DSM impacts in its Base Cases for 2013- 2015, while DEP's projections drop below the actual savings in 2017. Figure 4, below, shows DEC's actual energy savings impacts in 2010-2012, represented by the three squares on the left of the graph, and DEP's savings impacts, represented by the three diamonds. As shown in Figure 4, after leveling off in the middle years, both DEC and DEP's long-term energy efficiency forecasts decline in the later years of the IRP planning horizon. This decline is hard to reconcile with the fact that emerging technologies and new efficiency measures will allow the companies to not only maintain, but increase their savings.

Figure 4: Duke Energy Actual and Forecasted Base Case EE Impacts, 2010-2028

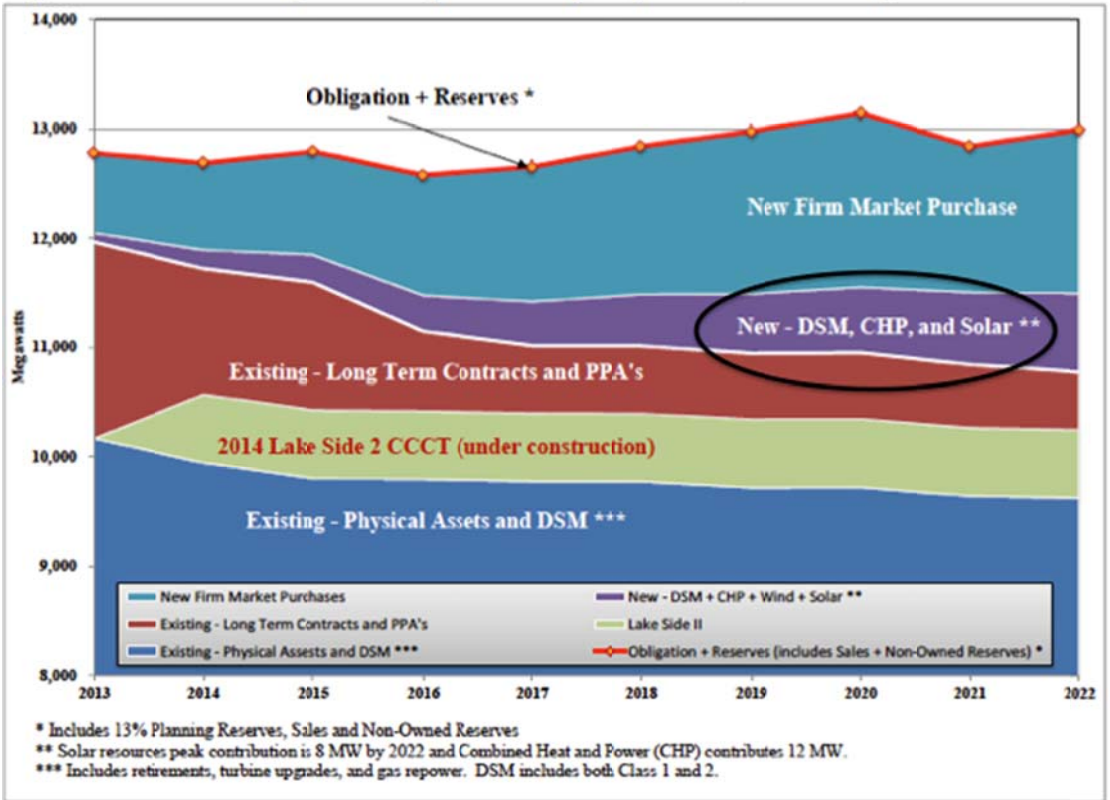


DEC and DEP should improve their efficiency modeling to allow the resource to grow in the long term, consistent with the long-term efficiency forecasts of electric utilities that have successfully delivered efficiency savings for decades. The Northwest Power and Conservation Council, for example, concluded that at least 85% of the projected 20-year energy savings estimates in its first regional plan were realized, demonstrating that long-term planning and results can be achieved.[42] One of the utilities affected by those regional plans, PacifiCorp, anticipates sustained growth of the contribution of DSM resources in its IRP, as illustrated in Figure 5.

[42] 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 5: PacifiCorp Preferred Resource Portfolio, 2013 IRP

Figure 8.30 – Addressing PacifiCorp's Peak Capacity Deficit, 2013 through 2022



PacifiCorp, 2013 Integrated Resource Plan, 2013. Volume I at 231.

One major barrier to proper integration of EE into the DEC and DEP 2013 IRPs is DEC and DEP's modeling of energy efficiency as a fixed model input, best characterized as an adjustment to the load forecast rather than as a resource that may be optimized during the modeling process. While this treatment is appropriate for demand response measures, the industry best practice is to treat energy efficiency investments as equal or even preferred to supply-side resources for planning purposes.[43]

[43] 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.

DEC and DEP 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 uses two supply curves for energy efficiency in the model that develops least-cost portfolios.[44] The use of two supply curves allows for different treatment of discretionary and lost-opportunity energy efficiency resources.[45] 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 that DEC and DEP use does not allow this distinction to be made.

3. Increased Levels of Energy Efficiency Could Avoid at Least Two NGCC Units.

The 2013 DEC and DEP IRPs show that, taken together, Duke Energy's operating utilities in the Carolinas are planning to build 7,442 megawatts ("MW") of new conventional generating capacity over the 15-year planning horizon, including five NGCC units over the next decade, and two new nuclear units in 2024 and 2026. DEC 2013 IRP at 36. While it is unlikely that all of the forecasted NGCC units can be avoided through energy efficiency alone, aggressive but achievable levels of energy efficiency could avoid the 1,800 MW that DEC and DEP have identified in needed capacity by 2022.

In its 2013 IRP, DEC projects energy efficiency programs will reduce demand and load by about 6% of retail sales by 2022, or about 950 MW; DEP projects about 5%

[44] Id. at 71.

[45] 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.

by 2022, or about 450 MW. Achieving just this 1,400 MW of savings, as planned, will enable DEC and DEP to avoid building at least one large and one small generating unit. The companies can and should achieve greater energy savings, however.

DEC and DEP should develop energy efficiency programs designed to achieve at least 1% retail savings per year, amounting to a roughly 10% reduction in demand and load over a 10-year period—a rate achieved by numerous utilities across the nation, as discussed later in these comments. Achieving this 10% benchmark would require DEC and DEP to roughly double their energy efficiency program impacts, resulting in roughly 1,100 MW of *additional* avoided capacity by 2022, as illustrated in Table 6, below.[46] Based on this rough forecast, DEC and DEP could reduce the five planned NGCC units to only three such units over the next decade.

Table 6: 2022 Energy Efficiency Projections by Utility

Energy Efficiency Savings	Duke Energy Carolinas	Duke Energy Progress	Duke Energy System
Base Case Energy Savings (Percent of Retail Sales)	6.1%	4.6%	5.6%
Base Case Capacity Avoided (MW)	949 MW	451 MW	1,400 MW
10% Energy Savings Capacity Avoided (MW)	1,556 MW	980 MW	2,535 MW

Duke Energy argues that the premise that higher levels of energy efficiency are achievable is in conflict with the estimate of achievable efficiency potential provided by

[46] Achieving this rough 10% benchmark would be a slightly more aggressive goal than the amount studied by Duke Energy in its Environmental Focus scenarios. Those scenarios studied 1,311 MW and 863 MW of peak energy efficiency impacts in 2022 for DEC and DEP, respectively. The impact of the total 2,174 MW of energy savings capacity avoided on the capacity expansion plans is described in the IRPs. While the 10% benchmark is more aggressive than the amount studied by DEC and DEP, it is not as aggressive as the goals already agreed to by DEC and DEP in the merger settlement, which included a 7% cumulative savings goal for just the five years 2014-2018.

Forefront Economics in its market potential study.[47] However, as acknowledged by Forefront, the study "has not been designed to provide detailed specifications and work plans required for program implementation. Accordingly, this study provides *part* of the information to use in setting DSM savings goals or targets."[48] The report goes on to state, "Although the five-year plan reflects a significant increase in DSM, it is not meant to provide an estimate of maximum achievable potential."[49] Thus, the potential study is avowedly conservative, and not indicative of all of the cost-effective, achievable savings available to Duke Energy.

Duke Energy has also insinuated that only states with high electricity rates have achieved high levels of energy efficiency savings .[50] To the contrary, several states, such as Minnesota, New Mexico, and Washington have lower average electricity prices than North Carolina and demonstrate a history of achieving higher annual energy efficiency impacts.[51]

What Duke Energy does not contest is that its IRP methods did not select an "optimum" level of energy efficiency in balance with other resources. The two levels

[47] SC Response to Comments, p. 6-7.
[48] Duke Energy Carolinas: Market Assessment and Action Plan for Electric DSM Programs North Carolina. Prepared by Forefront Economics, Inc and H.Gil Peach & Associates LLC. February 23, 2012. Page 1. NCUC Docket No E-7 Sub 1032 (emphasis added).
[49] Duke Energy Carolinas: Market Assessment and Action Plan for Electric DSM Programs North Carolina. Prepared by Forefront Economics, Inc and H.Gil Peach & Associates LLC. February 23, 2012. Page 3. NCUC Docket No E-7 Sub 1032
[50] "The states listed as examples of this level of achievement … have some of the highest electricity prices …" Duke Energy, SC Response to Comments, p. 7. Although witnesses for Duke Energy Carolinas and Progress Energy Carolinas argued vigorously that electricity prices and energy efficiency achievement were related in 2010, the NCUC did not adopt that argument in its decision to accept the utilities' 2009 energy efficiency savings forecast. Instead, the NCUC noted that the programs are "in their early stages" and took note of the opt-out provision of North Carolina Senate Bill 3. NCUC Order, Docket E-100 Sub 118 and Sub 124, August 10, 2010 p. 14-15.
[51] Energy Information Administration, State Electricity Profiles. Available at http://www.eia.gov/electricity/state/; Downs, Annie, et al. American Council for an Energy Efficient Economy, The 2013 State Energy Efficiency Scorecard. Table 14. 2011 Net Incremental Electricity Savings by State.

studied in the modeling represent planning assumptions that were input as adjustments to the load forecast. These assumptions are based on Duke Energy's opinion regarding the "expected rate of adoption of EE measures by customers," an outcome that Duke Energy is uniquely positioned to influence. The Commission has not reached any specific findings or even opined on whether Duke Energy's planning assumptions reflect consideration of any and all energy efficiency programs with the highest reasonably achievable customer response rates to cost-effective offers.[52]

In fact, DEC has a track record of achieving higher levels of energy efficiency than its conservative planning practices forecast. While exceeding expectations is generally commendable, when conservative planning assumptions are repeatedly exceeded, they can no longer be considered "conservative" and should instead be considered unrealistic and indefensible. The result is a planning process in which excessive amounts of new generation are deemed necessary when in fact reasonable, cost-effective alternatives exist.

It would be possible to model EE as a resource that could be selected by the model, or to model various levels of EE as sensitivities to identify the point at which EE becomes less cost-effective to the system. Without considering a broader range of energy efficiency resource opportunities, the utilities have placed unreasonable limitations on their resource planning process.

[52] In its order on the 2012 IRPs, the Commission simply found that, "the IOUs have included an adequate discussion of their market potential studies, including updates, for DSM and EE programs in their 2012 IRPs." NCUC Order, Docket E-100 Sub 137, October 14, 2013 p. 31. This topic was not discussed in preceding orders, see: NCUC Order, Docket E-100 Sub 118 and Sub 124, August 10, 2010 p. 14-15; E-100 Sub 128 October 21, 2011 p. 33. May 30, 2012.

Many utilities—both in states with higher rates and in states with rates comparable to or even lower than those in the Carolinas—are achieving higher levels of energy efficiency than DEC and DEP. By increasing their energy savings, DEC and DEP could defer and eventually avoid even more of the planned generation capacity in their IRPs. Instead, by failing to act on these opportunities year after year, DEC and DEP are gradually and imprudently foreclosing less costly alternatives to building new generation or extending the operating lifetime of existing generation.

4. Increased Levels of Renewable Energy Could Substantially Alter the Utilities' Capacity Plans.

Due to deficient evaluation of renewable energy resources in their past and current IRPs, it is unclear how much of the company's identified need for additional capacity through 2022 could be met with RE resources like wind and solar. Only in the 2013 IRPs have DEC and DEP provided any evaluation of RE as a resource (as opposed to a compliance strategy), but even this evaluation is lacking in crucial respects.

For the Base Case, DEC and DEP restrict their analysis of solar and wind energy resources to compliance with the North Carolina Renewable Energy Portfolio Standard ("REPS"). In contrast, another major electric utility in the region, Georgia Power, plans to have over 750 MW of solar on its system by 2018. Notably, a 2012 report from the South Carolina Public Utility Review Committee ("PURC") Energy Advisory Council ("EAC") concluded that there is up to 1,700 megawatts of near-term solar potential available in South Carolina.

In their modeling, the utilities stacked the deck against renewable energy: Both utilities claim to have considered solar and wind energy in their "expansion planning model." DEC 2013 IRP at 22 and 44; DEP 2013 IRP at 22 and 41. In fact, renewable energy resources were effectively excluded from the Base Case, whose model input files did not include any solar or wind resource capacity options. Renewable energy resources were input into the System Optimizer ("SO") model according to specified capacity and schedule, without flexibility to increase, decrease, or reschedule those resources.[53] DEC's Vice President for Integrated Resource Planning and Analytics, Janice D. Hager, acknowledged in testimony before the South Carolina Public Service Commission that, while DEC's IRP model could pick from various supply-side resource options, **DEC did not allow its capacity expansion model to select solar or energy efficiency resources**.[54]

DEC has also acknowledged that intermittent resources are compatible with new combined cycle plants such as those included in its IRP. During the hearing referenced in the preceding paragraph, DEC Director of Project Development and Initiation, Mark Landseidel, testified that "the intermediate capability of the [natural gas combined cycle] plant allows it to fluctuate as needed to meet the system needs," which could vary for reasons "including intermittent power sources," such as solar, and that operating the unit at a lower output would not decrease the facility's useful life since the plant is designed

[53] In addition to the exclusion of renewable energy as a resource available to the model, Duke Energy's SO model files include two technical errors related to renewable energy modeling, which have been confirmed by Duke Energy verbally and in response to Data Request 2-8. The resource "Solar Fixed REN DEC" was set up with a 100% capacity factor, resulting in a small amount of extra solar energy being included in the SO runs. The resources "DEP Solar no FITC 2" "DEP Wind no FITC 2" were set up with BookLife equal to 1 rather than 60, resulting in no solar or wind energy from these resources being produced after the initial year 2028 (the resources were only included in the Environmental Focus scenarios). While neither of these errors was likely consequential, the oversight suggests that Duke Energy analysts did not scrutinize the modeling of RE resources closely enough to determine whether these resources were performing cost-effectively.

[54] South Carolina Public Service Commission Docket No. 2013-392-E, Tr. Vol. 2 at 109:20-23; 111:24-2; id. at 139:5-9.

with the capability for cycling and operation at minimum loads,.[55] Mr. Landseidel also recognized that operating the unit at a lower output would reduce water use, as well as air emissions.[56] Thus, in addition to offering the opportunity to reduce plant operating costs, solar (and wind) power resources reduce environmental impacts.

a. *Wind energy development costs are decreasing, not increasing.*

Duke Energy's 2013 Supply Side Data Manual indicates that Duke Energy estimates wind development costs to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] per kW in 2013, declining to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] per kW in "2015 and beyond." These estimates are slightly higher than the $1,500 to $2,000 per kW estimated by Lazard, an independent financial advisory and asset management firm.[57] The 2013 capital cost input into SO by Duke Energy is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] per kW for wind power, roughly in the midpoint of the Lazard range. An inflation factor is applied to this estimate so that the 2015 SO capital cost input is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] per kW, which exceeds Duke Energy's data manual forecast for wind resource costs for that year and, due to the use of the annual inflation factor, beyond.

Any projection of wind development costs must explore several interrelated trends. Three key trends characterize the recent wind power market:

- Modestly declining project development costs;

[55] Tr. Vol. 2 at 166:5-8; 165:7-13.
[56] Tr. Vol. 2 at 166:23; 167:18.
[57] Lazard, *Levelized Cost of Energy Analysis – Version 7.0* (August 2013). Earlier versions of this report have been provided by Duke Energy in a response to data requests for relevant cost source material.

- Turbine design changes have boosted project capacity factors; and
- Project siting in lower-quality wind resource drove down project capacity factors.

Taken together, these three factors have resulted in gradually declining power purchase agreement ("PPA") prices.[58] These prices are generally expected to continue declining.[59] Thus, while Duke Energy selected a reasonable starting point for its wind resource development cost forecast, the overall wind cost trend used in the 2013 IRPs appears contrary to both its own data manual as well as findings by national energy laboratory experts.

b. *Solar energy development costs are decreasing, not increasing.*

Duke Energy anticipates solar resource costs to decline. Internal studies and external references, as well as the 2013 Supply Side Data Manual, reflect this projected decline. Moreover, Paul Newton, Duke Energy President – North Carolina, recently spoke before the North Carolina Joint Legislative Commission on Energy Policy and indicated that Duke Energy forecasts declining solar prices.

DEC and DEP did not employ this assumption of declining solar prices in their expansion planning modeling, however. Instead, solar resource costs were input into System Optimizer with an inflation factor so that costs increase, rather than decline, beginning in 2014. The 2013 capital cost input into SO by Duke Energy is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] per kW for solar power, significantly lower than the [BEGIN CONFIDENTIAL] [redacted] [END

[58] Lawrence Berkeley National Laboratory, *2012 Wind Technologies Market Report* (August 2013).
[59] National Renewable Energy Laboratory, *IEA Wind Task 26: The Past and Future Cost of Wind Energy*, NREL/TP-6A20-53510 (May 2012).

CONFIDENTIAL] per kW indicated in the data manual, but at the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] end of the $1,750 to $2,000 per kW range in the Lazard report.[60] After application of the annual inflation factor, the 2015 SO capital cost input is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] per kW, which exceeds Duke Energy's data manual forecast of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] per kW. As with wind power, the discrepancy grows as the application of inflation runs counter to a declining solar cost trend.

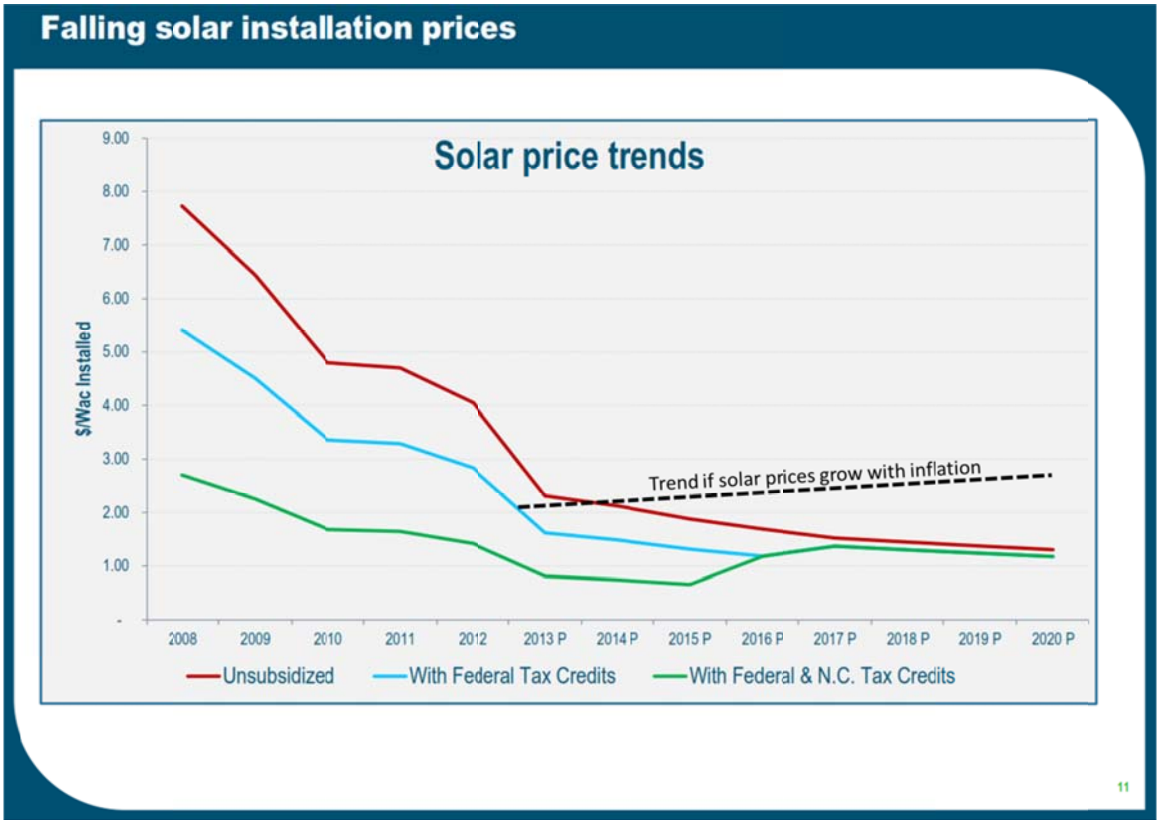
The contrast between the inflation-based cost escalation and forecasts of solar development costs based on market data is illustrated in Figure 6 below, adapted from Mr. Newton's presentation.[61] Superimposed on the "solar price trends" described by Mr. Newton, the SO model's application of a standard inflation rate to solar energy results in costs that are roughly twice as high for 2020.

---

[60] Lazard, *Levelized Cost of Energy Analysis – Version 7.0* (August 2013). Earlier versions of this report have been provided by Duke Energy in a response to data requests for relevant cost source material.

[61] Paul Newton, "Duke Energy in North Carolina," presentation to the Joint Legislative Commission on Energy Policy, January 7, 2014, available at http://www.ncleg.net/documentsites/committees/BCCI-6576/4%20-%20Jan.%207,%202014/Presentations%20and%20Handouts/3%20-%20Newton%20-%20Duke%20Energy%20Overview.pdf. The "Trend if solar prices grow with inflation" was added to Duke Energy's illustration for comparison purposes.

Figure 6: Duke Energy Forecast for Solar Installation Prices



Prices may be headed even lower than Duke Energy forecasts. The long-term forecast in DEC and DEP's data manual bottoms out above the midpoint of Lazard's estimate of 2013 solar power development costs. A "low" estimate included in Duke Energy's data manual (but not applied to its actual forecast) cites credible evidence from a neighboring utility that the cost of solar energy development is actually much lower than Duke Energy's data manual forecast. In addition to declining costs, capacity factors are on the rise: Lawrence Berkeley National Laboratory ("LBNL") reports that some solar energy projects have been built with "oversized" PV panel arrays, resulting in a higher capacity factor.[62] These higher capacity factors can translate into lower delivered costs of generated electricity.

Although the company is well aware that solar and wind costs are rapidly declining, Duke Energy's capacity planning modeling assumed immediate and sustained escalation in wind and solar costs. As a result, these resources are overpriced and undervalued throughout the most important part of the planning period. Correcting this faulty assumption would increase the level of solar power identified as cost-effective by the resource planning models—if DEC and DEP configure the models to offer flexibility in the time and amount of renewable energy capacity investments.

c. *Market-driven solar energy development is on the rise.*

Another way that renewable energy development could substantially alter DEC and DEP's capacity expansion plans is through the market-driven growth in installation of solar power by their customers. This trend has been acknowledged by the utilities: their load forecast captures distributed generation as a net load reduction, represented as a forecast that net metering of solar systems will grow from 8 MW in 2013 to 248 MW by 2028. While this may appear to be a large increase, the resulting 413 GWh of generation in 2028 would still represent only 0.2% of total generation on the DEC and DEP systems. Neither DEC nor DEP are planning for sharp increases in distributed solar generation.

Duke Energy's public statements suggest that its management anticipates far more solar distributed generation than its planners currently include in system models. Mr. Newton's testimony described a "cost burden" caused by "a shifting of costs from those

---

[62] Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2012: An Empirical Analysis of Project Cost, Performance and Pricing Trends in the United States* (September 2013). At these projects, the nameplate capacity is established by the capacity rating of the inverter rather than the output of the panels.

who want solar panels to those who do not."[63] There is mounting evidence that, contrary to this presumption, net metering customers in fact provide greater benefits to the system than the costs they impose. Moreover, the alarm Mr. Newton is trying to raise about the alleged unfairness of net metering is overblown given Duke Energy's projection that net metering will only account for 0.2% of total generation by 2028.

How much solar and wind resource capacity could be cost-effectively deployed over the next fifteen years? Without an evenhanded modeling analysis, it is not possible to answer this question. However, the costs of utility-scale solar power development may already be so low that it is effectively cheaper to build a large solar power plant than to operate a natural gas plant when the sun is shining, as indicated by the following examples:

- Xcel Colorado recently proposed adding 450 MW of wind, 170 MW of utility-scale solar, and 317 MW of natural gas generation.[64] According to the independent evaluator's report, the wind and solar reduce the overall system cost by $262 million, with about 94% of those cost savings due to reduced operating costs (not capacity savings).[65] Thus, the independent operator effectively confirmed that it would be less costly for customers if the utility were to build renewable energy simultaneously with a combined cycle gas plant than to build just the gas plant.

[63] Paul Newton, "Duke Energy in North Carolina," presentation to the Joint Legislative Commission on Energy Policy, January 7, 2014.
[64] Xcel Colorado website, http://www.xcelenergy.com/About_Us/Energy_News/News_Releases/Xcel_Energy_proposes_adding_economic_solar,_wind_to_meet_future_customer_energy_demands (accessed December 6, 2013).
[65] Accion Group, Independent Evaluator's Final Report: Public Service Company of Colorado, 2013 All-Source Solicitation, Colorado Public Utilities Commission Proceeding 11A-869E (October 9, 2013), available at https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_195074&p_session_id.

- On March 27, 2014, the Minnesota Public Utilities Commission voted 4-0 to direct Northern States Power (Xcel) to negotiate a power purchase agreement for a 71 MW solar PV project proposed by Geronimo along with one of three natural gas generation proposals.[66] In its evaluation of the alternatives considered to meet a 150 MW capacity need demonstrated by Xcel, the Minnesota Office of Administrative Hearings recommended that the first 71 MW of capacity need be met by Geronimo's solar PV project proposal, with remaining capacity need to be supplied by either Great River Energy (a cooperative generator with surplus capacity from a mix of conventional and renewable resources) or a new natural gas turbine.[67]
- The City of Austin recently approved a purchase power agreement with Sun Edison for a term of up to 25 years without additional cost.[68] The long-term fixed pricing obtained by Austin Energy is $45 – 55 per MWh, which "is competitive with expected market prices for on-peak energy" (regardless of source).

In each of these cases, the cost-effectiveness of solar power was demonstrated in a head-to-head comparison with conventional generation resources, without the assistance of a mandate or state incentive. In the Carolinas, it is not yet clear whether or not solar energy can be procured at a cost similar to the cost to fuel and operate a combined cycle

[66] Adam Belz, "Largest-ever Minnesota Solar Project Gets Tentative Regulator Approval," *StarTribune* (March 28, 2014).

[67] The hearing officer laid out specific steps for determining the amount, type and schedule for the additional capacity resources. Office of Administrative Hearings, State of Minnesota, "Findings of Fact, Conclusions of Law, and Recommendation, In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process," MPUC Docket No. E-002 / CN-12-1240 (December 31, 2013).

[68] "The contract is expected to have a neutral impact to the power supply adjustment (PSA)." City of Austin, Recommendation for Council Action, Item ID 31382 (March 20, 2014).

gas plant. When that benchmark is reached (if not already), ***it is likely to be cost-effective for utilities to invest in several gigawatts of solar power.***

5. Changes in Utility Load Forecasts Could Substantially Alter the Utilities' Capacity Plans.

Recent statements by Duke Energy management suggest that its Carolinas operating utilities' load forecasts are down sharply since the spring 2013 load forecasts used in the 2013 IRPs. On a November 6, 2013 earnings call, Duke Energy CEO Lynn Good commented, "Long-term, we've have been planning for 0.5% to 1%. And we are actually challenging our team to think about an environment with that kind of load growth, even trending to flat over time potentially, as we think about sizing our O&M spending."[69]

In contrast to the low-growth future described by Ms. Good, the 15-year growth rate in the DEC and DEP plans combined is nearly 1.5%; simply reducing that growth rate to 1% would mean cutting cumulative 15-year growth from 24% to 16%. This suggests that not only could energy efficiency and renewable energy meet load growth over the next fifteen years, but DEC and DEP could continue to retire aging power plants with minimal need for conventional replacement capacity.

C. A Closer Examination of the Environmental Focus Scenarios Reveals That Higher Levels of Energy Efficiency and Renewable Energy Would Reduce Customer Costs and Price Risks.

The Environmental Focus Scenarios in the 2013 DEC and DEP IRPs demonstrate that more aggressive—but still achievable—levels of energy efficiency and renewable energy would save customers ***roughly $1 billion over the next 15 years*** across Duke

[69] Duke Energy, "Q3 2013 Duke Energy Corporation Earnings Conference Call," Earnings Call Transcript (November 6, 2013).

Energy's service territory in the Carolinas as compared to each company's "preferred" plan, as summarized in Table 7.[70]

Table 7: Customer Cost Savings from Environmental Focus Scenarios

15- Year Revenue Requirement Forecast ($ billions present value)	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy System**
Environmental Focus Case	$ 46.1	$ 29.3	$ 75.4
Base Case	$ 46.6	$ 29.9	$ 76.5
Potential Savings	**$ 0.5**	**$ 0.6**	**$ 1.1 billion**

Both DEC and DEP reject the Environmental Focus scenario because they calculate the present value of revenue requirements ("PVRR") as $1.3 and $0.1 billion higher, respectively, than each utility's Base Case, "even with deferral of the advanced CC and CT resources." Each IRP cites the same factors, "the higher CO_2 price projection, increased revenue requirements associated with higher EE and increased costs associated with doubling the amount of renewables," as causing the higher PVRR. (DEC p. 47, DEP p. 45, and DEC and DEP Supplement to 2013 IRPs (Mar. 7, 2014) p. 2). However, although the operating company IRPs imply that Duke Energy recommends against pursuing the Environmental Focus Scenario because of the "increased revenue requirements," Duke Energy later indicates that this comparison "is not intended for the selection of one portfolio over the other."[71]

DEC and DEP each reached the wrong total system cost estimate (i.e., PVRR) when evaluating the Environmental Focus Scenario. Together, DEC and DEP have

[70] Duke Energy made significant changes to its modeling for this IRP. Although some data were provided in a 40-year modeling time horizon, many data were provided for shorter periods. As a result, these comments focus on Duke Energy's 2014-2028 planning period. Accordingly, the $2 billion in cost savings identified in these comments is not directly comparable to the higher cost savings estimates identified in our comments on prior IRPs because those estimates were developed for a 50-year study period rather than this 15-year study period.

[71] SC Response to Comments p. 10.

overestimated the combined cost of their Environmental Focus Scenarios by about $2.5 billion. Correction of three flaws in the utilities' modeling, discussed in further detail below, reveals that the PVRR for the Environmental Focus scenario is $1.1 billion lower than each utility's Base Case. Thus, rather than costing about $1.4 billion more than the Base Case, **the more aggressive energy efficiency and renewable energy resource strategy outlined in the utilities' Environmental Focus Scenarios could save their customers $1.1 billion over the next 15 years**, as summarized in Table 8.

Table 8: Customer Cost Savings from Environmental Focus Scenario

15- Year Revenue Requirement Forecast ($ billions present value)	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy System**
EF Case as Reported by Duke	$ 47.9	$ 29.9	$ 77.8
- Use base case CO_2 prices	- 0.7	- 0.6	- 1.3
- Use base case fuel prices	+ 0.3	+ 0.1	+ 0.4
- Escalate EE costs at LBNL rate plus inflation	- 1.3	- 0.2	- 1.6
EF Case with Corrections	$ 46.1	$ 29.3	$ 75.4
Base Case	$ 46.6	$ 29.9	$ 76.5
Potential Savings	**$ 0.5**	**$ 0.6**	**$ 1.1**

The analytic flaws that resulted in grossly overstated costs for the Environmental Focus scenarios are discussed in the following sections.

1. <u>The Higher "Carbon Price" and Lower Fuel Price Forecast Used in the Environmental Focus Scenario Makes It Impossible to Compare Its Total Cost With That of the Base Case Scenario on an "Apples-to-Apples" Basis.</u>

The utilities forecast a "carbon price" of $20-45/ton in the Environmental Focus Scenario compared to $17-33/ton in the Base Case. DEC 2013 IRP at 21; DEP 2013 IRP at 21. The higher carbon price accounts for about $1.3 billion in increased costs in the

Environmental Focus Scenario.[72] Although a high carbon price may in fact combine with other factors to drive higher levels of EE and RE in the future, the assumption of a higher carbon price in the Environmental Focus Scenario does not permit a fair, "apples-to-apples" comparison with the Base Case. Along with other factors discussed in this section, this makes the scenario with higher levels of energy efficiency and renewable energy appear more expensive than the Base Case.

On the other hand, Duke Energy also modeled fuel prices at a different level in the Environmental Focus Scenario, resulting in $0.4 billion in decreased costs.[73] It appears that, in the Environmental Focus Scenario, Duke Energy modeled the fuel price of coal to be lower across all years as stated in both IRPs. Yet, for natural gas, it appears that the modeled fuel price may have been higher for some years and lower for other years than the Base Case forecast. The $0.4 billion combined effect of these changes is included in our "apples-to-apples" comparison above in Table 8.

2. The Utilities Use an Escalation Rate for Energy Efficiency Program Costs That Relies on Flawed Cost Assumptions and Practices.

The long-term forecast for energy efficiency program costs applied by the utilities in their cost forecast indicates cost escalation far in excess of the rate of inflation, to an extreme that is inconsistent with the cost forecast methods used for other resources. In comparison with a more reasonable forecast of energy efficiency program costs, Duke

[72] This estimate was calculated by multiplying the emissions forecast for the Environmental Focus Scenario by the emissions prices used in the Base Case, and comparing these costs with those reported by DEC and DEP. This method does not account for additional cost savings that would occur due to re-dispatch.
[73] In comments filed with the South Carolina Public Service Commission, this adjustment was not discussed or included in the analysis. We acknowledge that an error was made in our analysis of this issue that resulted in it not appearing significant enough to quantify, and have corrected this error for these comments.

Energy's excessive forecast accounts for $1.6 billion in increased costs in the Environmental Focus Scenario.

Duke Energy has offered scant justification for its inflated forecast. In response to a criticism in comments filed with the South Carolina Public Service Commission of the excessive cost forecast for energy efficiency programs, Duke Energy has claimed that it "is simply not the case" that "ever higher levels of EE can be accomplished without an increase in the cost per MW to achieve these higher levels.[74] It is true that an increase in the cost per MW may occur at higher levels of efficiency; however, research has shown that as utility programs scale up to higher levels of market penetration, every dollar in program costs can achieve more savings.[75]

3. Several Additional Factors Suggest That the Savings From Energy Efficiency and Renewable Energy Would Be Even More Than $1.1 Billion.

The overall estimate of savings for the Environmental Focus Scenario, as summarized in Table 7, is conservative because it does not adjust for several factors:

- As discussed above, Duke Energy's capital cost model assumes that solar and wind energy development costs increase at the rate of inflation through 2028, when in fact

[74] SC Response to Comments, p. 10. SACE requested data pertinent to achieving a detailed understanding of DEC's and DEP's energy efficiency program forecasts. In response to a request for cost projections, the companies provided detailed cost projections for DEC energy efficiency programs covering 2013-17, as well as other detailed data related to demand response (or DSM) programs. For DEP, and DEC beyond 2017, the energy efficiency program cost data were provided as a summary of total costs with no detail or explanation. In response to a request for any new assessment of energy efficiency program costs and potential, Duke provided an updated study addressing the potential for energy efficiency, but the study scope did not include the assessment of program costs. **Thus, even with a broad request and a voluminous response by Duke, none of the data provided by Duke indicate how or why Duke's energy efficiency program costs are forecast to escalate so rapidly.**

[75] Takahashi, K and D Nichols, *The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date,* 2008 ACEEE Summer Conference, August 2008. While the upper limit for economies of scale in utility-led energy efficiency hasn't been established to our knowledge, it appears certain that it is well over the 1% benchmark discussed earlier in our comments.

the cost and technical performance of both solar and wind are likely to improve over the next 5 to 10 years. The capital cost model should be adjusted to reflect these cost trends, which would reduce the cost of solar and wind energy in the Environmental Focus Scenario.

- Adjusting carbon and fuel prices to compare the cost of the Base Case with the Environmental Focus Case does not include adjusting the dispatch of units to an optimal level given the carbon and fuel prices. Each case should be run with the carbon and fuel price levels used in the other to determine how the different strategies affect production costs due to better optimized fleet dispatch.
- Duke Energy did not complete the study of a fourth scenario, including an optimal mix of energy efficiency and renewable energy resources developed under a joint planning approach.

While it is not possible to calculate the impact of these three factors on overall revenue requirements, addressing these three factors could further reduce the total revenue requirement on the order of a billion dollars. Also, many of the investments that would occur under Duke Energy's Environmental Focus Scenarios fall during the final years of the 2014-2028 planning period; while a substantial portion of the costs of this strategy occur within the planning period, the benefits of these investments would occur outside the planning period, and are therefore excluded from the estimates in these comments.

Furthermore, incorporating higher levels of energy efficiency and renewable energy in the utilities' plans results in lower risk than does any strategy using base case assumptions. Thus, a resource plan that includes the "the least cost mix" of resource options and reduced risk of cost increases should include more aggressive levels of energy efficiency and renewable energy than DEC and DEP present in their 2013 plans.

In light of the savings opportunity indicated by the Environmental Focus Scenarios, DEC and DEP should select preferred plans that include significantly higher levels of energy efficiency and renewable energy than in their Base Cases.

4. Energy Efficiency and Renewable Energy Are Well-Matched With Opportunities to Cut Utility System Costs.

Production costs – fuel, variable, and fixed costs – make up nearly [BEGIN CONFIDENTIAL] [redacted] END CONFIDENTIAL] of the costs included in the resource plans' revenue requirements. In contrast, the capital expansion plans of the utilities over the next fifteen years—while they represent billions of dollars—still make up only about [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of the costs. To further reduce system costs, the smart planner should look to cut production costs, and renewable energy and energy efficiency are ideal resources to do this.

Figure 7: Total System Cost of Duke Energy's Resource Portfolios, Base Case vs Environmental Focus Case.[76]

[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

In our evaluation of DEC's 2012 IRP, we described how higher levels of energy efficiency reduced system costs. About 80 percent of gross savings were due to reduced fuel use, which is included in production costs, but about 20 percent of the system cost savings were due to avoiding new generation (as represented by reduced capital costs).[77] In stark contrast, there was a zero cost difference between the gas, nuclear and regional nuclear portfolios under base case assumptions. Similarly, the DEP modeling showed

[76] Figure 3 was derived from DEC and DEP's quantitative analysis in their IRPs, as described in Appendix A. See DEC 2013 IRP at 43-51; DEP 2013 IRP at 40-47.

[77] Note that these data, while similar to 2013 data DEC required be maintained as confidential, were disclosed with DEC permission in prior comments.

that the high energy efficiency case saved billions, while there was virtually no difference between the other four generation plans that DEP studied.[78] In the 2013 IRP, DEC and DEP focused their alternatives on the Environmental Focus Scenario and the Joint Planning Scenario, as described above.

The Joint Planning Scenario demonstrates that DEC and DEP together can avoid the construction of unnecessary resources and operate more efficiently. DEC and DEP also initiated a study of the Environmental Focus Scenario utilizing the Joint Planning Scenario assumptions; according to Duke Energy staff, this study was not finalized. The Joint Planning Scenario described in the IRPs indicates a 15-year savings opportunity of $0.4 billion.[79] While joint dispatch savings are already authorized for DEC and DEP, the utilities are not yet authorized by either Commission to share firm capacity. The utilities' IRPs explain how joint planning reduces unnecessary investments by deferring and avoiding generation capacity.

For example, in its application for certification of a new NGCC unit at its Lee Steam Station, DEC acknowledges that, under the Joint Planning Scenario, the proposed Lee NGCC unit could be deferred to 2018 "under the proper conditions," and states that DEC and DEP will be investigating an arrangement to share capacity.[80] A joint planning arrangement represents a step towards reducing system costs, but should be employed in combination with a strategy that optimizes investment in energy efficiency and renewable energy.

---

[78] Initial Comments of Sierra Club and SACE, NCUC Docket No. E-100, Sub 137 at 6-8.
[79] This comparison does not include the updates to Duke's modeling included elsewhere in these comments. Duke Energy did not update the Joint Planning Scenario when it updated the other two model cases. Duke Energy reply to SACE DR 2-10.
[80] Direct Testimony of Janice D. Hager, Docket No. 2013-392-E at 20.

5. Increased Use of Energy Efficiency and Renewable Energy Would Expose Customers to a Lower Risk of Cost Increases.

In addition to lowering total system cost, energy efficiency and renewable energy also lower the risk profile of a resource mix. Futures and other conventional financial instruments can provide utilities with tools to hedge against natural gas price risk. However, a recent Lawrence Berkeley National Laboratory report indicates that such financial instruments are limited to hedging over five- to perhaps ten-year time periods.[81]

Wind and solar energy resources could lower the risk profile of the DEC and DEP resource mixes. As documented in a recent National Renewable Energy Laboratory ("NREL") study, wind power contracts provide a hedge that can extend twenty years or more, helping to protect customers "against many of the higher-priced natural gas scenarios contemplated by the [Energy Information Administration]," even in today's low gas price environment, and even without the benefit of the production tax credit.[82] Demonstrating the impact of renewable energy resources on fuel price risk for the DEC and DEP systems is more challenging since the utilities have given the topic such cursory attention in their resource planning studies.

In the 2012 IRPs submitted by DEC and DEP, the qualitative analysis of risk shows that increased levels of energy efficiency resources expose customers to less risk than the utilities "preferred" investments in natural gas or nuclear alternatives. DEC and DEP did not conduct any sensitivity analyses for the 2013 IRPs and thus failed to renew

[81] Lawrence Berkeley National Laboratory, *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*, LBNL-6103E (March 2013).
[82] National Renewable Energy Laboratory, *The Use of Solar and Wind as a Physical Hedge against Price Variability within a Generation Portfolio*, NREL/TP-6A20-59065 (August 2013).

their evaluation of risk.[83] DEC and DEP have not provided any new information regarding the risks associated with demand-side resources in the 2013 IRPs. Instead, the IRPs continue to present only a cursory discussion of risks associated with increased levels of efficiency, such as uncertainties about customer participation and regulatory approval, and do not compare these risks to the risks associated with the supply-side resources included in the preferred portfolios, such as nuclear power. DEC 2013 IRP at 16, DEP 2013 IRP at 16. Despite this shortcoming in both plans, data from DEC and DEP's IRP analyses allow for a degree of quantitative and qualitative comparison, which shows that the risks presented by energy efficiency and renewable energy resources are, in fact, lower than those for supply-side resources, as discussed in the following subsections.

a. *Fuel and environmental cost risks.*

DEC and DEP customers bear a substantial risk of price increases if fuel prices and environmental costs, such as a price on CO_2 emissions, are higher than anticipated because these costs are passed through to customers. As discussed below, neither DEC nor DEP considered increased levels of energy efficiency or renewable energy resources as a way to mitigate fuel price risks. EE and RE resources are, however, more effective at reducing fuel price risk than any conventional supply-side resource, and this should have been considered in the companies' IRPs.

As illustrated in Table 9, below, the higher level of CO_2 emissions in the Base Case (the utilities' preferred strategy) exposes customers to a greater cost risk for compliance with CO_2 regulations than the Environmental Focus Case:

[83] In response to a data request (SACE 1-3), Duke Energy explained, "In the 2013 IRP update year the company provided scenario analysis but did not conduct individual variable sensitivities."

Table 9: Relative Sensitivity to Carbon Dioxide Regulation, Duke Energy System[84]

15-year Carbon Price ($ billions present value)	**Base Case**	**Environmental Focus Scenario**
Higher Price Base Price	[BEGIN CONFIDENTIAL] [redacted]	[redacted]
Cost Risk		[END CONFIDENTIAL]

Unsurprisingly, the cost of paying for CO_2 regulatory compliance is lower when higher levels of energy efficiency and renewable energy are implemented, as demonstrated in the Environmental Focus Scenario. In contrast, the higher-emission Base Case and Joint Planning Scenario strategies are riskier, with a price sensitivity almost [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] greater than the Environmental Focus Scenario. Thus, with respect to carbon risk, DEC and DEP are choosing the higher-risk plan.

Neither DEC nor DEP have adequately assessed a broad range of environmental risks in the quantitative analyses conducted for their 2013 IRPs. DEC and DEP only considered environmental risks from a compliance perspective. DEC 2013 IRP at 27 and 44; DEP 2013 IRP at 27 and 41. In contrast, the Tennessee Valley Authority ("TVA") evaluated the environmental impacts of each alternative resource portfolio in terms of air emissions, water impacts (heat transferred to the environment), and waste disposal costs (coal ash and nuclear) in its 2011 IRP. TVA 2011 IRP at A172-A181. Adopting a broader approach, similar to that used by TVA, would allow DEC and DEP to be more explicit about how they balance various environmental risks.

[84] Values in italics represent estimates calculated using modeled emissions and the respective carbon price.

DEC's fuel price risk analysis appears to have played a major role in its selection of a preferred plan in its 2012 IRP, which is carried forward in its 2013 IRP with some updates. Although DEC cites the reduced fuel cost risk in support of including nuclear generation in its plan, DEC ignored the fact that energy efficiency resources have an even lower fuel price risk than do supply-side resources.[85]

In the past, DEC modeling data have shown how higher energy efficiency resources reduce system risk due to fuel price variability more effectively than portfolios that include higher nuclear or gas resource alternatives. SACE's analysis of DEC's 2010 and 2011 IRPs showed that, under conditions of high fuel and high CO_2 prices, selecting the High EE/DSM strategy would mitigate price spikes by $1-2 billion.[86] This held true regardless of the type or level of supply-side investment under consideration. For its 2013 IRP, however, neither DEC nor PEC conducted similar analyses of high energy efficiency and renewable energy investments, particularly with respect to fuel cost risk.[87]

In its 2012 IRP, DEP appeared to view natural gas prices as its main fuel cost risk. Natural gas prices represented the single largest risk of total system cost impacts in DEP's sensitivity analysis.[88] "High Gas Prices" were considered as a component in two of the four scenarios DEP used. DEP 2012 IRP at A-6. DEP gave a 30% weight to

[85] To the extent that DSM resources bear a "fuel cost" risk, it is likely inversely correlated with electric rates. As electric rates rise, DSM participation incentives could increase and thus result in higher participation rates. An exception would be standby generation DSM programs.

[86] This price spike mitigation is in addition to the cost advantage demonstrated for High EE/DSM resources in the base case. See SACE Comments on DEC's 2011 IRP, Docket No. E-100, Sub 128 (Jan. 13, 2012) at 4. DEC has asserted in prior proceedings that it does not run High DSM sensitivities under varying cost conditions, such as high fuel and CO_2 prices. However, this assertion runs counter to DEC's own modeling data, which it provided in responses to data requests.

[87] Adjusting the CO_2 prices for the various scenarios, as illustrated in Table 9 presents a simple analysis for this variable. However, because we were not able to re-dispatch the Base Case under the higher CO_2 price, or the Environmental Focus Case under the lower CO_2 price, our illustration provides only an approximate result.

[88] PEC Response to Informal Data Request in 2012 IRP.

System Fuel Price Volatility in its ranking of alternative plans, which considered variation in gas prices but not coal, uranium, or other fuel prices. Id. at A-6 - 7.

Even given this evident concern, DEP's 2013 IRP continues to ignore the value of energy efficiency resources in reducing fuel and environmental cost risk. As described in our comments on DEP's 2012 IRP, a plan with High EE resources results in lower fuel and other production costs than the four alternative plans DEP modeled in its scenario analysis.[89]

Moreover, if DEP had evaluated its 2012 IRP High EE case for System Fuel Price Volatility, it would have scored substantially better than any of the four alternative plans emphasized by DEP. As illustrated in Table 10 below, not only did DEP's High EE plan have $4.3 billion in lower costs, but the plan resulted in a reduced rate of price growth and lower system fuel price volatility.

Table 10: Customer Cost Attributes of Alternative Resource Plans[90]

DEP 2012 IRP	Preferred Plan (A)	Plan B	Plan C	Plan D	High EE Plan
Revenue Requirement ($ Billions)	$ 87.5	$ 87.6	$ 88.7	$ 87.8	$ 83.2
Price Growth	3.8 %	3.7 %	3.9 %	3.7 %	3.4 %
System Fuel Price Volatility	8.7	9.8	9.6	8.4	7.8

In addition to failing to provide a fuel cost risk analysis for the High EE case, DEP failed to evaluate EE/DSM resources in its quantitative analysis of environmental (air emissions) impacts. DEP 2012 IRP, Appendix A. As noted above, DEP, like DEC, should not ignore increased levels of energy efficiency and renewable energy as tools to

89 See Initial Comments of Sierra Club and SACE, NCUC Docket No. E-100, Sub 137 at 14.

90 The data in this table is from the PEC 2012 IRP at A-18, except as follows: The Revenue Requirement has been adjusted to include cost of energy efficiency programs. SACE performed the calculations for the High EE plan utilizing PEC workpapers by adjusting for High EE case fuel use and efficiency program costs.

reduce environmental compliance costs and impacts in light of increasingly stringent regulations.

Duke Energy has recently asserted that "Fuel and environmental costs associated with each type of resource are modeled in the IRP and each resource bears the associated fuel and environmental cost as part of the economic selection process within the IRP." (PSC Response to Comments p. 8). The implication of this assertion—that renewable energy resources do not decrease fuel and environmental cost risks—is false in two respects. First, as discussed elsewhere in these comments, Duke Energy staff have confirmed that energy efficiency, solar energy, and wind energy are not actually modeled as part of the economic selection process. Second, DEC and DEP have not modeled do not include approximately $7.7 billion in costs associated with upgrading their existing coal-fired generation resources to meet forthcoming environmental regulations.

b. *Capital cost risk.*

Another source of risk is the potential for capital cost increases. Energy efficiency programs have relatively low annual expenses (i.e., fuel and operating costs) compared to fossil fuel generation. Most of the cost associated with efficiency is program cost; as a one-time resource investment, program cost is more similar to capital cost than fuel or operating costs.

In their 2012 IRPs, both DEC and DEP performed a sensitivity analysis to assess the risk of increasing capital costs. However, as with fuel and environmental cost analyses, neither utility performed these sensitivity analyses on High EE/DSM case resources, instead focusing on nuclear and gas resources. In our comments on the 2012 IRPs, we applied the methods used by DEC and PEC for supply-side resource cost risk and demonstrated that EE/DSM programs present far lower capital cost risks than do supply-side resources. In their 2013 IRPs, DEC and DEP forecast energy efficiency program costs to escalate at well above the rate of inflation. While it would be reasonable for DEC and DEP to consider a high-cost forecast as a sensitivity or risk analysis tool, it is unreasonable to rely exclusively on such a high-cost forecast.

It is true that there may be capital cost risks associated with renewable energy resources, just as with conventional supply-side resources, since they both rely on similar material and global supply markets. As noted above, the lack of quantitative data studying such risks in the DEC and DEP IRPs makes it impossible to quantify any such risks. Also as discussed elsewhere in these comments, Duke Energy agrees that the capital costs associated with wind and solar energy are trending downward, so the degree of risk is mainly around how quickly costs will decline, not how likely they are to increase in cost.

Even the lack of quantitative data does not deter Duke Energy from attempting to portray solar power as unusually risky from the perspective of cost increases. In recent comments, DEC and DEP state, "given that a majority of … [solar] equipment are manufactured in China, capital cost uncertainty is subject to normal supply and demand fluctuations in addition to foreign exchange risk when projected for future years." (PSC Response to Comments at p. 8). Duke Energy fails to apply this haphazard perspective uniformly to other energy resource alternatives. For example, nuclear power generation components are likely to be sourced from foreign manufacturers and are hence likewise subject to foreign exchange risk. Duke Energy's insertion of a new source of risk into the analysis is yet another instance of the company's failure to evaluate energy resources in an evenhanded manner.

To the extent that energy efficiency and renewable energy capital costs decline more slowly than anticipated (or even, perhaps, escalate), those risks can be mitigated by the nature of those resources. Due to much smaller economies of scale (on the order of tens, rather than hundreds, of megawatts), these resources are acquired on an annual basis, rather than in large increments as with a new power plant. DEC has suggested that a regional nuclear portfolio has a financial advantage over other supply side resources 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." DEC 2012 IRP at 109. The impact of energy efficiency and renewable energy costs on customer bills are spread out even more broadly over time, and therefore represent a lower risk alternative to supply-side resources.

c. *Risk of scheduling inflexibility.*

Large power plant projects are relatively inflexible in terms of development schedule, making it difficult to adjust in response to changing conditions and increasing the risk of delay. As DEC and DEP note with respect to its regional nuclear portfolio, "sharing new baseload generation resources between multiple parties allows for resource additions to be better matched with load growth...." DEC 2013 IRP at 49; DEP 2013 IRP at 46.

Unlike large power plant projects, energy efficiency programs and renewable energy development projects are flexible and can be managed to more closely match load growth because these resources are deployed in annual increments. DEC and DEP discuss constraints on the pace of bringing new energy efficiency programs online, citing uncertain technology development, regulatory approval, market channel development, and program flexibility as challenges to expanding program scale. DEC 2013 IRP at 91; DEP 2013 IRP at 81. Yet analogous constraints on supply-side development, including multiple regulatory approvals, site acquisition and development, and transmission constraints, are far more significant. Compared to supply-side resources, energy efficiency programs are relatively straightforward and inexpensive to expand, cancel or modify in response to changes in projected (or even experienced) load growth.

DEC and DEP contest the advantages of renewable energy with respect to scheduling uncertainty with a non sequitur: "overreliance on this one particular resource [solar] has not proven to be the reliable least cost option, and to an extent defies the principles of long-term generation planning." (PSC Response to Comments p. 8) It is unclear what, if anything, this statement has to do with scheduling uncertainty. In any event, the notion that either DEC or DEP has experience with "overreliance" on solar power is preposterous.

DEC and DEP's evaluation fails to recognize that energy efficiency and renewable energy resources offer scheduling flexibility that is a valuable asset. In the event of an increase or reduction in load growth, the opportunity to rapidly adjust the resource plan with small increments of new capacity reduces the unnecessary carrying costs of excess capacity that may occur due to inaccurate forecasts.

d. *Risk of implementation failure.*

Like conventional supply-side resources, implementation of energy efficiency programs and renewable energy development is subject to market or regulatory barriers.

Concerns about siting sometimes apply to wind and solar development projects. On the demand side, lower-than-forecasted customer participation is a potential risk.

Both DEC and PEC cite customer participation as an obstacle to achieving higher levels of energy efficiency, stating that "At this time there is too much uncertainty . . . in the ability to secure high levels of customer participation to risk using the high EE savings projection in the assumptions for developing the 2013 integrated resource plan." DEC 2013 IRP at 91; DEP 2013 IRP at 81. However, DEC or DEP do not point to any data in support of this conclusion in the IRPs, energy efficiency program filings, or energy efficiency potential studies. Customer participation could be tapped out at some point, but there is no indication that this will occur during the DEC or DEP IRP planning horizon.

Failed program implantation is a risk for all energy resources, but many escape this scrutiny in the IRPs. For example, both DEC and DEP's preferred plans consist of full or partial ownership of nuclear units, despite several obstacles to the timely, safe and cost-effective development of nuclear power units, as discussed in Section V., below. As in prior IRPs, the utilities do not explain why the risk of failed program implementation associated with higher levels of energy efficiency is greater than the risks associated with the development of supply-side resources, such as nuclear power plants.

6. Duke Energy's Resource Evaluation Criteria Are Unclear.

Prudent resource planning should result in a preferred plan that minimizes costs while managing risks and achieving other objectives required by law or Commission orders. In developing their 2013 IRPs, however, DEC and DEP do not appear to have followed this approach. Duke Energy has claimed that the cost comparison between the

Base Case and Environmental Focus Scenario in each utility's IRP are "not intended for the selection of one portfolio over another." (PSC Response to Comments p. 10) If that is the case, the purpose of analyzing different scenarios is unclear, and furthermore suggests that Duke Energy's planning process intentionally excluded energy efficiency and renewable energy resources from the actual portfolio selection process. Further, as discussed above, Duke Energy's evaluation of the risks associated with energy efficiency programs and renewable energy development is haphazard and dismissive.

We recommend that the Commission order DEC and DEP to evaluate both cost and risk for energy efficiency and renewable energy resources using an approach that is equivalent to the approach they use for conventional supply-side resources. The Commission should then order DEC and DEP to explicitly analyze various higher levels of EE and RE investment, which the utilities' IRPs have shown to lower total system costs and risk, and determine what levels should be adopted in future recommended plans.

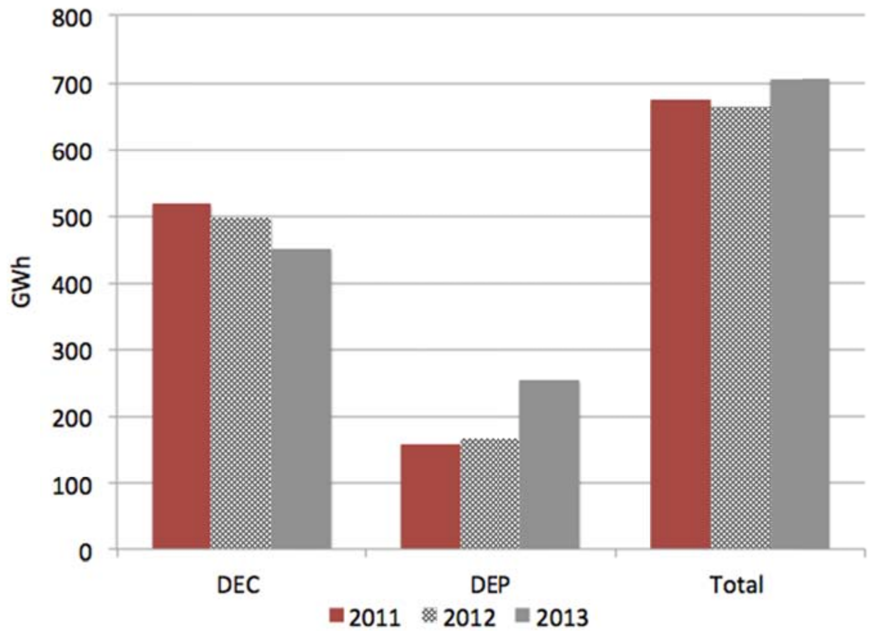
IV. ENERGY EFFICIENCY

Energy efficiency is an abundant, least-cost resource. Yet DEC and DEP are not taking advantage of the resource, as shown by their flawed modeling of both the costs and impacts of energy efficiency discussed above. Although DEC continues to lead the Southeast in energy efficiency, DEC projects that its savings will plateau while DEP and utilities in other states and are ramping up their efficiency savings. If these trends bear out, DEC will slip from its position as a Southeast leader on efficiency in 2014 or 2015. Numerous opportunities remain for both DEC and DEP to capture additional efficiency impacts, as discussed below.

D. DEC Continues to Lead on Efficiency in the Southeast, Yet Opportunities for Improvement Remain.

DEC has continued to be a leader on energy efficiency, but it does not appear that it will continue to do so in 2014. DEC's energy efficiency impacts declined slightly from 2011 to 2013, while DEP's increased. Taken together, Duke Energy's Carolinas operating utilities increased their energy efficiency impacts from 2011 to 2012, as shown in Figure 8 below.

Figure 8: Duke Energy 2011-2013 Energy Efficiency Impacts[91]



Duke Energy's Carolinas operating utilities are delivering high-performing, cost-effective energy efficiency programs to their customers. In particular, DEC's energy efficiency program performance is among the best in the Southeast. In 2011 and 2012 DEC led the

[91] NCUC Docket E-7 Sub 1050, Application of Duke Energy Carolinas, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider, Direct Testimony of Tim Duff, Exhibit 1. NCUC E-2 Sub 1030, Duke Energy Progress Application, Appendix D. NCUC Docket No. E-2 Sub 1019, Progress Energy Carolinas Application, Appendix D; NCUC Docket No. E-2 Sub 1002, Progress Energy Carolinas Application, Appendix D.

Southeast in energy savings from efficiency, saving more than 0.5% of annual sales, equal to about 500 GWh of efficiency savings both years.

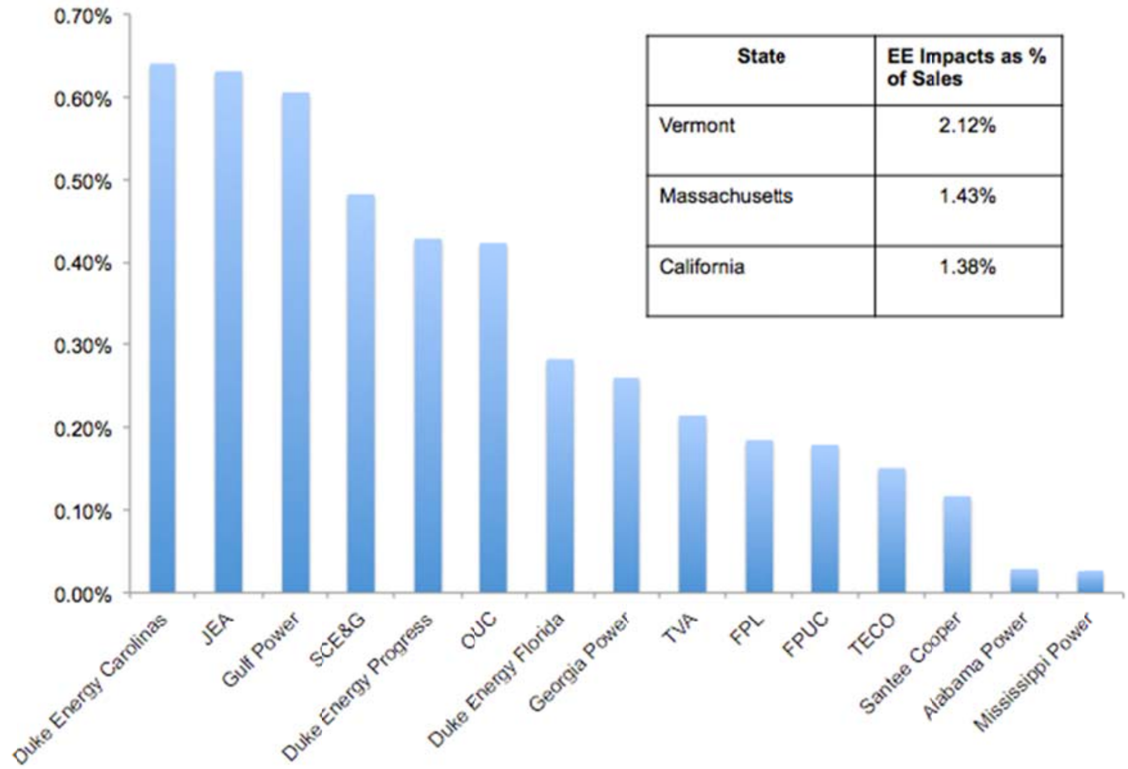
DEC and DEP have also kept the cost of their energy efficiency programs low. DEP's programs came in under budget in 2011 and 2012; although DEC significantly exceeded projected savings, which increased the absolute cost of its programs, it lowered the cost per kWh saved.

Table 11: Projected Costs, Actual Costs and Actual Savings of DEC and DEP Energy Efficiency Programs

Duke Energy Carolinas			
	2011	2012	2013
Cost Estimate (million $)	N/A	$22.8	$40.0
Actual Cost (million $)	$43.7	$50.5	$48.9
Actual Impacts (GWh)	518	498	452
Impacts as a percentage of prior year sales	0.69%	0.58%	0.60%
Duke Energy Progress			
Cost Estimate (million $)	$29.7	$40.2	$40.2
Actual Cost (million $)	$28.7	$28.8	N/A
Actual Impacts (GWh)	158	166	254
Impacts as a percentage of prior year sales	0.36%	0.44%	0.58%

As shown in Figure 9, below, DEC achieved far greater cost-effective energy savings than other major utilities in the Southeast. DEP's energy efficiency program performance is improving, but lags behind DEC and several other utilities in the region.

Figure 9: Efficiency Impact as a Percentage of Retail Sales, 2012



Based on preliminary data for 2013, DEP is closing the gap between it and DEC, but it does not appear that DEC will continue to be the efficiency leader in the Southeast.

1. <u>Duke Energy still is not planning to utilize energy efficiency as a resource at levels that will continue to place it as a leader in the SE.</u>

Despite successful program delivery and improved efficiency forecasting, neither company's actual savings or forecasted future program impacts reflect the level of savings that are being achieved in leading states. As shown in Figure 9, above, utilities in leading states are saving from 1.5 – 2% of their sales each year. Taken together, DEC and DEP project that they will achieve between 8-17% cumulative energy savings from energy efficiency programs at the end of their IRP planning cycle, as shown in Table 12, below:

Table 12: Energy Efficiency Projections by Utility

	Final Year	Cumulative Savings as % of 2028 Sales	
		Base Case	Environmental Focus Scenario
DEC	2028	9.3%	14.3%
DEP		6.6%	15%
Duke Energy System		8.3%	14.5%

These forecasts, including the higher levels of EE/DSM savings used in the Environmental Focus Scenarios, are significantly lower than those of utilities in leading states.

Further, the DEC and DEP Base Case savings forecasts project annual savings of far less than 1% of sales per year. To meet the five-year EE performance targets set forth in the December 8, 2011 settlement agreement negotiated in connection with the merger of Duke Energy and Progress Energy, DEC and DEP would each need to achieve annual savings of 1.4%.[92]

E. DEC and DEP Have Many Opportunities to Increase Their Cost-Effective Energy Efficiency Offerings.

New programs are critical to the companies' achievement of the higher levels of energy efficiency modeled in their Environmental Focus Scenarios.[93] This is particularly true because almost 100% of DEC's incremental projected EE/DSM savings in its Environmental Focus Scenario (compared to 28% of its Base Case savings) are from

[92] In the S.C. Public Service Commission ("SC PSC") proceeding related to the merger of Duke Energy and Progress Energy, Docket No. 2011-158-E, the companies entered into a settlement agreement with SACE, Environmental Defense Fund, and the S.C. Coastal Conservation League (the "Merger Agreement"), in which, among other things, DEC and PEC agreed to annual energy savings target of 1% beginning in 2015, and a cumulative target of 7% of retail sales from 2014-2018. The Settlement Agreement was approved by the SC PSC in its Order Approving Joint Dispatch Agreement, Order 2012-517 (July 11, 2012) at 43.

[93] South Carolina Docket 2013-392-E, Rebuttal Testimony of Janice D Hager at 11.

unidentified programs and measures.[94] DEP did not provide granular enough data to determine similar values.

1. New Energy Efficiency Program Ideas

To achieve a higher level of savings, DEC and DEP must implement new EE/DSM programs. In its recent order approving DEP's annual DSM/EE rider, the Commission endorsed DEP's formation of a collaborative, and strongly encouraged the collaborative to consider several program suggestions made by SACE.[95] Programs that DEC and DEP should consider are shown in Table 13 below.

Table 13: Energy Efficiency Programs that DEC and DEP Should Consider[96]

Program Type	Example Program/Provider	Description
Multi-Family	NYSERDA Multifamily Performance Program	Provides escalating incentives for greater savings levels and challenges multifamily owners to reduce total source energy consumption by 15%. The impact evaluation for this program will be available in Q1 2014.
Midstream Incentives for HVAC	Energy Solutions for PG&G, SCE, NV Energy, SDG&E and SMUD	HVAC distributors receive tiered incentives to stock and upsell high efficiency HVAC equipment.
Commercial Commissioning or Re-commissioning	Xcel Energy in Colorado and Minnesota	Xcel pays for up to 75% of re-commissioning study cost, and an implementation rebate of up to $0.08 per lifetime kWh saved.
Commercial New Construction	MidAmerican in Iowa	Incentives offered by Carolinas utilities are applicable to new construction in the non-residential market, however a program targeted at new construction for non-

[94] DEC Response to SACE Data Request 1-19.

[95] North Carolina Utilities Commission, Final Order Approving DSM/EE Rider, Docket No. E-2 Sub 1030 (Jan. 24, 2014).

[96] In the Settlement Agreement in Docket No. E-7, Sub 1032, DEC agreed to discuss with the Collaborative low-income programs, CHP, on-bill repayment, and the impact of commercial and industrial customers opting out of Duke Energy's programs. Accordingly, those measures and concepts are not discussed in the table below. Natalie Mims' testimony in Docket No. E-7, Sub 1032 includes additional recommendations on programs targeting manufactured homes, residential new construction, low-income grocery retro-commissioning, universities, municipalities, and industrial customers.

		residential doesn't exist. MidAmerian offers incentives to offset the cost of higher initial costs associated with the design and installation of energy efficient building options.
Truveon	Piedmont EMC	Piedmont is piloting Truveon technology in a residential efficiency program. Truveon software provides info for residential HVAC right-sizing and continuous commissioning. Truveon projects savings of 40% on residential HVAC.

2. Low-income programs could be scaled to benefit the entire system if all benefits were appropriately considered.

Programs targeted to low- and fixed-income customers can help these customers reduce their electricity bills, which often represent a significant share of household budgets. DEP has offered a neighborhood low-income program for several years, and DEC has recently adopted a similar program. Low-income customers are one of the most underserved sectors on the electric system and could benefit the most from energy efficiency. Still, programs targeted to low-income customers often fail the standard cost-effectiveness tests due to faulty assumptions about their costs and benefits.

In an effort to develop cost-effective low- and fixed-income energy efficiency programs, Duke Energy should take a broader look at the costs and benefits associated with serving low- and fixed-income customers in the Carolinas. The costs and benefits that are not currently captured by the avoided cost or the energy efficiency savings are sometimes referred to as Other Program Impacts ("OPIs").[97] Programs targeted to the low- and fixed-income sector have numerous OPIs; for example, reduced customer

[97] Woolf, Tim, et al. Energy Efficiency Cost-Effective Screening. RAP and Synapse Energy Economics. November 2012. Available at: http://www.raponline.org/event/the-importance-of-effective-energy-efficiency-cost-effectiveness.

arrearages and reduced bad debt write-offs for utilities, as well as improved health and safety, increased comfort and aesthetics, and reduced maintenance costs for participants. The scope of the problem is illustrated by the fact that in the fourth quarter of 2013 alone, DEP disconnected over 5,000 customers for non-payment.[98]

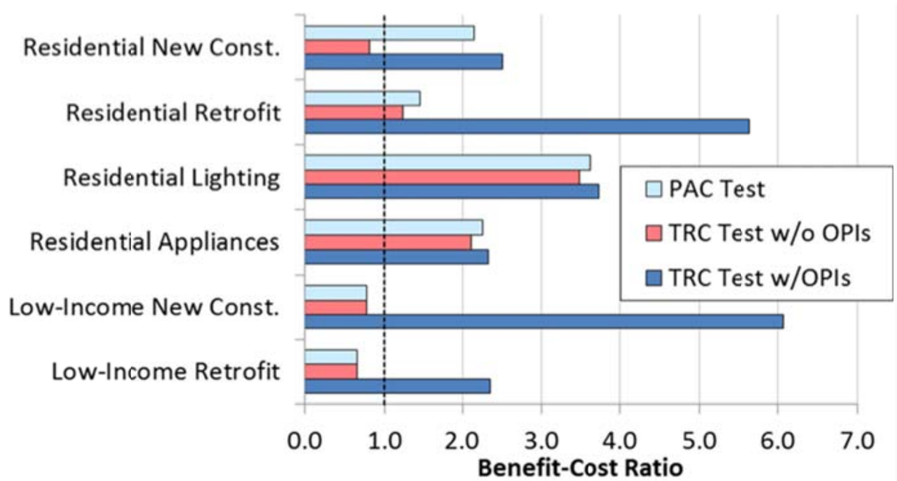
OPIs are particularly important when using the Total Resource Cost ("TRC") test, one of the standard tests used to determine program cost-effectiveness.[99] Currently, there are 12 states that account for OPIs in their TRC evaluation.[100] North Carolina is not one of those states. Accordingly, in the current TRC test as applied by DEC and DEP, OPI benefits are not accounted for and show up in the cost-test as having zero value—resulting in a TRC score that is skewed and misleading. The Commission should reconsider the inequitable result of counting all costs, but not all benefits, as the current Total Resource Cost test does.

Figure 10, below, shows six Massachusetts energy efficiency program cost-test scores: first using the program administrator test, second using the total resource cost test without OPIs, and finally the total resource cost test with OPIs.[101] As the chart shows, when OPIs are considered in the cost-effective evaluation, the low-income new construction and low-income retrofit programs move from being uneconomic to cost-effective.

---

[98] SC PSC Docket No. 2006-193-EG. Filed January 21, 2014.
[99] Woolf, Tim, et al. Best Practices in Energy Efficiency Program Screening. Prepared for National Home Performance Council by Synapse Energy Economics. July 2012. Available at: http://www.nhpci.org/images/NHPC_Synapse-EE-Screening_final.pdf
[100] Woolf, Tim, et al. Energy Efficiency Cost-Effective Screening, page 5. RAP and Synapse Energy Economics. November 2012. Available at: http://www.raponline.org/event/the-importance-of-effective-energy-efficiency-cost-effectiveness.
[101] Excerpted from Woolf, Tim, et al. Energy Efficiency Cost-Effective Screening. RAP and Synapse Energy Economics. November 2012. Available at: http://www.raponline.org/event/the-importance-of-effective-energy-efficiency-cost-effectiveness.

Figure 10: Massachusetts Energy Efficiency Program Cost-Test Scores



3. Better Universal Access to Data

In addition to new programs, DEC and DEP could provide their customers with better access to their electricity data. There are many ways to do this, including participation in the national "Green Button" effort, which created a template for utilities to provide consumers their usage data in an easy-to-access and easy-to-use format. The major advantage of offering consumers their electricity data in a consistent format is that it allows them to easily share their consumption data with third-party efficiency vendors who can show customers how to reduce their energy consumption and save money. This is a major opportunity to open up the energy efficiency market and allow new providers to offer energy savings with lower transaction costs. DEC and DEP should either participate in the Green Button effort or find other ways to provide customers with ready access to their own usage data.

4. Large customer opt-out provisions represent a lost energy savings opportunity for DEC and DEP.

The energy-intensive industrial and large commercial customer sectors can achieve significant energy efficiency impacts and, without capturing those impacts, it will be difficult for DEC to meet the five-year EE performance targets set forth in the December 8, 2011 Settlement Agreement. Further, customers who opt out receive system benefits provided by those customers who do participate in the companies' programs, but opted-out customers do not have to bear any of the costs unless they install their own measures. DEC's IRP portfolio analysis demonstrates that increased levels of energy efficiency lower total system cost, providing a universal benefit to all customers on the system. The system-wide, "universal" benefit occurs when efficiency reduces demand, average fuel costs are reduced, and system costs fall, which puts downward pressure on rates. Over the long term, as power plants are deferred or avoided entirely, the cost of building those power plants is not put into the rate base, placing further downward pressure on rates.[102]

5. DEC and DEP should leverage their size through market transformation programs.

As DEC and DEP integrate their operations following the merger of their parent companies, it follows that Duke Energy will begin to consider its energy efficiency portfolio across both operating companies. There is a significant opportunity for DEC and DEP to leverage their size and shift the market to become more efficient. For example, the Northwest Energy Efficiency Alliance, a regional energy efficiency group

[102] While some or all of the downward pressure on rates results from deferring or avoiding building power plants, this is counteracted by lost revenues associated with fixed costs from existing plants. However, opt-out customers, because they do not pay for the 36 months of lost revenues, are not affected by this and are effectively subsidized by all other customers.

in the Pacific Northwest, identifies barriers that impede market adoption and then intervenes to remove those barriers. NEEA works with over 140 utilities in the Northwest.

Given the significant market share they hold in the Carolinas, a market transformation program by DEC and DEP would have good prospects for success. An example of the type of program they could adopt would be offering a "midstream" incentive program to retailers and distributors in their service areas. This type of program offers relatively small incentives on a product unit, typically consumer electronics, which add up to big incentives for retails and distributors that sell many units. Midstream incentive programs have been successful in the Western US, and could be a major source of efficiency savings for both DEC and DEP.[103]

V. DUKE ENERGY DID NOT PROPERLY CONSIDER RENEWABLE RESOURCE OPPORTUNITIES.

F. DEC and DEP Continue to Ignore the Value of Renewables Beyond Their Contribution to System Energy and Capacity Needs.

Renewable energy resources such as solar and wind hold great potential for providing large amounts of clean, cost-effective power to Duke Energy's customers in the Carolinas. DEC and DEP have both begun to integrate meaningful levels of renewable resources onto their systems pursuant to REPS requirements, and the incremental cost of compliance for North Carolina customers has been modest.[104] Currently in 2014, DEC's North Carolina residential customers are receiving a $0.04 per

[103] See Dooley, Clair, et al., Plug Load Programs – Success, Attribution and Where We Go From Here. Presented at the ACEEE 2012 Summer Study and available at: http://aceee.org/files/proceedings/2012/start.htm

[104] For DEC residential customers, REPS costs averaged $0.29 per month from 2010 to 2013; for DEP residential customers, REPS costs averaged $0.55 per month from 2010 to 2013; see SACE, CCL, and Upstate Forever comments in SC PSC Docket No. 2012-10-E at 29.

month *credit* to their bills due to the REPS,[105] and DEP's monthly REPS cost to North Carolina residential customers is $0.19,[106] which is DEP's lowest REPS charge to date.

The installed costs of both solar and wind have fallen over time and are expected to continue to fall. While the REPS has helped drive DEC and DEP's procurement of renewables to date, with continual declines in installed costs, renewables at some point will likely become least cost—even when narrowly evaluated as satisfying nothing more than system energy and capacity needs. It is possible that that point has already been reached; unfortunately, it is impossible to determine from the 2013 IRPs for two main reasons. First, as discussed above, DEC and DEP treat renewables as fixed inputs to its model, preventing the model from selecting more or less renewable capacity than the companies have specified *a priori*. Second, the costs input into the DEC and DEP models are too high, as discussed above in Section III.

Solar and wind resources offer benefits to customers beyond energy and capacity that make them prudent additions to DEC's and DEP's resource plans, at levels well beyond that contained in the companies' current IRPs.[107] Given the potential benefits of renewables, it is critical that DEC and DEP improve their consideration of solar, wind, and other renewables within their IRPs so that cost-effective opportunities to deploy these valuable resources are not overlooked.

[105] NCUC Docket No. E-7, Sub 1034, Order Approving REPS and REPS EMF Riders and 2012 REPS Compliance (August 20, 2013).

[106] NCUC Docket No. E-2, Sub 1032, Order Approving REPS and REPS EMF Riders and 2012 REPS Compliance (November 25, 2013).

[107] In the 2013 IRPs, DEC projects that non-hydro renewables will make up only about [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of retail sales in 2013, and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in 2028; DEP projects that non-hydro renewables will make up about [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of retail sales in 2013 and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in 2028.

A simple first step would be to implement our previous recommendation to evaluate one or more "High Renewables" and/or "High DSM/High Renewables" candidate portfolios across multiple sensitivities of fuel cost, load growth, and other key variables, as was done in the 2012 IRPs for nuclear- and gas-focused portfolios.[108] Evaluation of one or more high renewables candidate portfolios across all sensitivities would highlight the ability of low-risk renewable resources to provide cost predictability to DEC's and DEP's portfolios across many possible futures. This analytical approach would allow the Commission–as well as DEC, DEP and interested stakeholders--to more fully understand the value renewable resources can offer beyond basic energy and capacity contributions.

Solar and wind energy resources often demonstrate measurable system benefits that are not often captured in integrated resource planning. These system benefits are particularly important for properly valuing solar energy since it is often interconnected closer to load and across many sites, unlike convention generation which is often sited remotely at a few locations. Solar energy resources in particular have a number of benefits (and costs), including:

- Transmission capacity benefits;
- Distribution capacity benefits;
- Grid support services;
- Grid security;
- Fuel price and regulatory hedging; and

[108] SACE, CCL, and Upstate Forever comments in SC PSC Docket No. 2012-10-E, at 34-35.

- Integration costs.[109]

As discussed in above, best practice resource planning already considers issues like fuel price and regulatory hedging (or at least puts a value on these risks). But with the possible exception of some transmission and distribution capacity benefits for distributed generation resources, neither DEC nor DEP have included any of these other benefits or costs in their resource planning evaluation of solar or wind power.

Both utility scale wind and solar power at, as well as distributed solar generation, have great potential for growth in the Carolinas, and could help DEC and DEP move towards a cleaner, low-cost, low-risk resource mix. However, DEC and DEP's analysis of renewable energy resources appears superficial compared with their analysis of conventional supply-side technologies.

G. Near-Term Potential for Solar Warrants Deeper Analysis.

Considering cost and resource availability, solar stands out as having the greatest near-term potential among renewable resources available in both DEC's and DEP's service territories. Duke Energy appears to have 673 MW of on-system solar installed in the Carolinas, including 414 MW of solar that contribute to REPS compliance, as summarized in Table 14. For each company, 99% of the total is located in North Carolina.

[109] Lena Hansen and Virginia Lacy, A Review of Solar PV Benefit and Cost Studies (Rocky Mountain Institute, September 2013).

Table 14: Solar Power in Duke Energy Service Territories (Primarily North Carolina)

2014 On-System Solar (MW)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy System
"Solar" Reported in IRP Section 5 (contributing to REPS compliance)	294	120	414
Solar Modeled in System Optimizer (contributing system resources)	361	312	673

Significant cost declines and supportive policies have driven a rapid expansion of both utility-scale and distributed (or "rooftop") solar installations across the U.S. in recent years., As shown in Figure 11, below, PPAs have been reported at a levelized price of below $60 per megawatt-hour ("MWh"); more recently SunEdison successfully submitted a $50 per MWh bid to Austin Energy.

Figure 11: Declining Costs of Solar PV Purchase Prices[110]

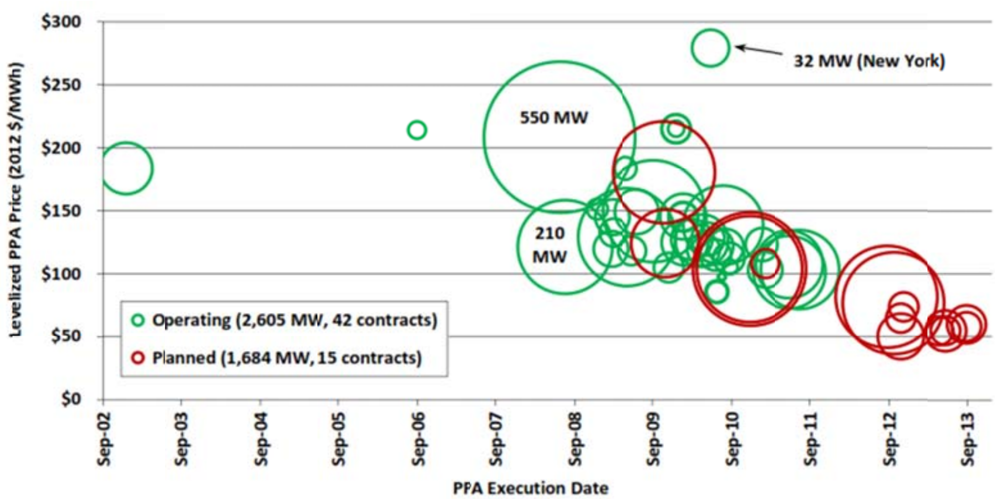
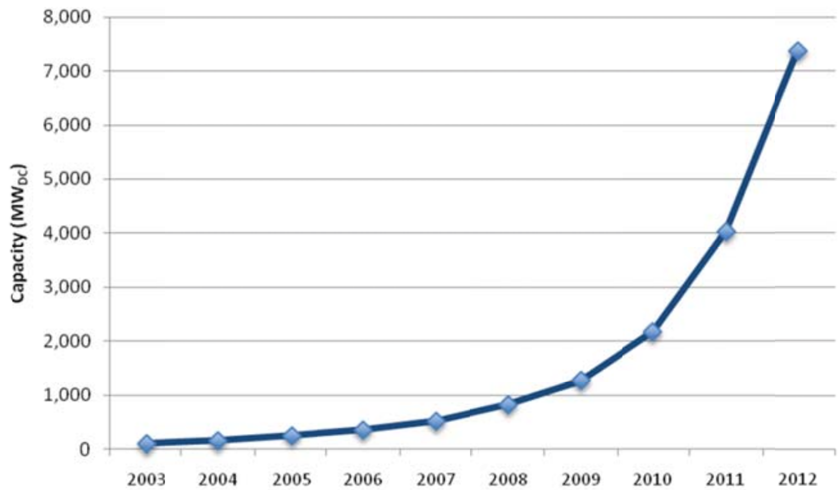


Figure 12, below, illustrates the rapid growth of solar photovoltaic capacity across the United States:

[110] Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2012: An Empirical Analysis of Project Cost, Performance and Pricing Trends in the United States* (September 2013).

Figure 12: Growth in U.S. Grid Connected Solar PV[111]



In North Carolina, development of utility-scale solar facilities were, at least initially, driven by REPS requirements. Since 2010, when DEC and DEP were first required to procure solar energy as part of the REPS, the cost of solar has declined significantly, as DEC acknowledges: "[t]he installed cost of solar resources has fallen dramatically over the past few years, driven by increased industry scale, standardization, and technological innovation." DEC IRP at 19.

In response to the increasing cost-competitiveness of solar power, utilities, regulators, and power sector stakeholders around the country have developed and refined methodologies for incorporating solar technologies into utility planning processes. DEC and DEP have considered solar technologies within their 2013 IRPs, but the companies have not analyzed solar technologies in as comprehensive a fashion as warranted by the

[111] Figure from Interstate Renewable Energy Council, 2013 Annual Updates and Trends Report (October 2013).

near-term potential of the resource to provide clean, low-cost, low-risk energy services on the DEC and DEP systems.

H. Distributed Solar Generation Opportunities Need Special Attention.

As discussed above, Duke Energy management has publicly expressed concern about the financial impact of customer-driven solar power installations. Yet the DEC and DEP projections of customer-owned solar distributed generation in their 2013 load forecasts, as noted in Section I.B.3 amount to an inconsequential [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL] system impact by 2028.[112] The resource planning implications of the large potential for distributed solar generation is discussed in a recent report by the National Renewable Energy Laboratory (NREL) and the Solar Electric Power Association (SEPA).[113] The NREL/SEPA report explains,

> Today's utility planners have a different market and economic context than their predecessors, including planning for the growth of renewable energy. State and federal support policies, solar photovoltaic (PV) price declines, and the introduction of new business models for solar PV "ownership" are leading to increasing interest in solar technologies (especially PV); however, solar introduces myriad new variables into the utility resource planning decision. Most, but not all, utility planners have less experience analyzing solar than conventional generation as part of capacity planning, portfolio evaluation, and resource procurement decisions.

The NREL/SEPA report encourages planners to consider evaluating distributed solar generation as a resource, including methods to capture distribution system impacts.

In DEC and DEP's resource planning studies, distribution system impacts are primarily evaluated through a standardized line loss assumption. However, distributed

[112] Although DEC and DEP provided net metering projections in response to a data request, the assumptions were not explained or sourced.
[113] John Sterling, Joyce McLaren, Mike Taylor, Karlynn Cory. Treatment of Solar Generation in Electric Utility Resource Planning. NREL Technical Report TP-6A20-60047 (October 2013).

solar generation impacts distribution systems in a significantly different way than conventional generation resources. A recent study of North Carolina utilities by Crossborder Energy found that distributed solar on DEC's and DEP's systems has a distribution capacity benefit of 0.2 to 0.5 cents per kWh on a 15-year levelized basis, and noted that distributed solar also avoids marginal distribution losses.[114] Because of this potentially significant benefit, the NREL/SEPA report recommends that utilities consider capturing the "distribution system impacts of DG and other technologies/activities in long-term plans."

Rather than modeling distributed solar generation as a reduction to load, DEC and DEP should evaluate it as a capacity and energy resource, allowing it to compete with other supply-side and demand-side resources within the planning process. For example, DEP's SunSense Solar PV program offers customers incentives for installing distributed solar generation on the DEP grid. Even though the SunSense program is one approach to "procuring" this customer-installed resource, DEP's 2013 IRP does not model an option to expand the SunSense program. In addition, DEC and DEP should conduct and file with the Commission a joint study of best practices for modeling utility-scale and distributed solar technologies and integrating such analysis into resource plans. Any such study should also be filed with the Public Service Commission of South Carolina.

I. Long-Term Potential for Offshore Wind Warrants Research and Development.

While the costs of electricity generated by offshore wind turbines are expected to be higher than the costs of alternatives at present, with industry development and falling

[114] R. Thomas Beach & Patrick G. McGuire. The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina (October 18, 2013).

construction and O&M costs, offshore wind could provide enormous amounts of clean power with little to no fuel or regulatory price risk. This resource also represents a prime economic development opportunity for North Carolina.

Given the medium- to long-term potential of offshore wind for the Carolinas, DEC and DEP should engage in R&D activities aimed at unlocking this energy resource at scale. DEC and DEP are involved in wind integration and interconnection studies, but the key near-term step in developing this resource is construction and operation of a demonstration-scale project sited in a manner to avoid the challenges experienced by the Pamlico Sound project. DEC and DEP should engage with other regional utilities, academic institutions, and economic development organizations to identify and initiate necessary studies and partnerships that would enable construction of an offshore wind demonstration project in North Carolina waters in the near future.

In addition to pursuing a near-term demonstration project, in the context of integrated resource planning it would also be useful to conduct a sensitivity study to identify a target at which offshore wind, developed in the 2020-25 timeframe, would be considered cost-effective. This would involve using a differential revenue requirement analysis of a hypothetical wind farm, using the best available information about energy output and effective load carrying capability or on-peak capacity.

VI. DEC'S AND DEP'S 2013 IRPS FAIL TO EVALUATE FULLY THE RISKS OF NEW NUCLEAR GENERATION

Both DEC and DEP include new nuclear generation in their 2013 IRPs. The companies' nuclear plans must be viewed in light of the history of nuclear power plant construction, which is riddled with cost increases, schedule delays and plant cancellations.

DEC's 2013 IRP states that the company continues to pursue the option for new nuclear generating capacity in the 2017-2028 timeframe. DEC'S Base Case and Environmental Focus Scenario both include full ownership of the planned 2,234 MW Lee Nuclear Station, with a 1117 MW unit coming online in 2024 and 2026 (pushed back from 2022 and 2024 in the 2012 IRP). (Under the Joint Planning Scenario, DEC's interest in the Lee nuclear units declines to 659 MW of each unit, although the in-service dates remain the same. DEC 2013 IRP, Table 8-H.) The Base Case and Environmental Focus Scenario also both include 5.9% ownership (66 MW) of the new V.C. Summer units under construction by South Carolina Electric & Gas Company ("SCE&G") and Santee Cooper, which are scheduled to come online in 2018 and 2020. DEC 2013 IRP at 47. DEC notes in its IRP that "the procurement of any portion of V.C. Summer is dependent on arriving at commercially acceptable terms with Santee Cooper." DEC 2013 IRP at 47. SCE&G recently announced that it is buying a 5% share of the V.C. Summer units from Santee Cooper, which presumably will affect DEC's potential procurement of a share of the units and will be reflected in DEC's 2014 IRP.[115]

Although DEP no longer includes a self-build nuclear option in the planning horizon, the company's 2013 IRP also includes new nuclear.[116] Like DEC, DEP states that discussions continue with Santee Cooper to purchase a 4.1% interest in the new V.C. Summer units—amounting to 46 MW in 2018 and another 46 MW in 2020 under both

---

[115] SCE&G buying additional capacity in new nuclear plants from partner Santee Cooper, The State, available at http://www.thestate.com/2014/01/27/3230548/sceg-buying-additional-capacity.html (Jan. 29, 2014).

[116] On May 2, 2013, DEP asked the NRC to suspend its review of the COL application for two proposed new nuclear units at the Harris Nuclear Plant site, "based on anticipated slower customer growth and the fact that our most recent forecast indicates two additional nuclear units at Harris will not be needed in the next 15 years." DEP 2013 IRP at 52.

the Base Case and Environmental Focus Scenario. DEP 2013 IRP at 7, 32, 37. DEP notes that procurement of any portion of V.C. Summer is dependent on meeting commercial terms with Santee Cooper. DEC 2013 IRP at 44. Again, as with DEC, SCE&G's decision to purchase part of Santee Cooper's ownership interest is likely to affect DEP's potential buy-in to V.C. Summer. Under the Joint Planning Scenario, DEP would acquire an ownership interest in DEC's Lee nuclear units, whose online date has been delayed to 2024 and 2026. DEP 2013 IRP at 7; Table 1A.

DEC's and DEP's nuclear plans are fraught with risks and uncertainties:

- DEC acknowledges "several challenges that have impacted the schedule for the Lee Nuclear facility." In the wake of the Fukushima nuclear disaster, the NRC requested in April 2012 that DEC update the site-specific seismic analysis for the Lee Nuclear Station, pushing the Nuclear Regulatory Commission's ("NRC") issuance of the Combined Construction and Operating License ("COL") to the second quarter of 2016 and delaying the online date for Lee Nuclear Unit 1 to 2024. DEC 2013 IRP at 49.
- Another challenge impacting the Lee schedule is the fact that a long-term solution to the problem of nuclear waste remains elusive, as recognized by a federal court's 2012 vacatur and remand of the NRC's Waste Confidence Rule. The NRC has suspended licensing of new nuclear reactors until it addresses the remand of the rule. Id.
- DEC and DEP both acknowledge in their IRPs that revisions to the steam electric effluent limitation guidelines ("ELGs") forthcoming in May 2014 will apply to nuclear facilities. DEC 2013 IRP at 108-09; DEP 2013 IRP at 102.

- The companies also acknowledge that nuclear fuel costs are expected to increase in the future "[a]s fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices." DEC 2013 IRP at 94; DEP 2013 IRP at 88.

Given that the Lee Nuclear Station would be one of the first new nuclear builds in the United States in decades, and considering the troubled history of U.S. nuclear construction, caution is warranted in estimating potential costs and construction lead times for new nuclear construction in DEC's and DEP's nuclear portfolios.

Recognizing the possibility of escalating nuclear construction costs, for its 2012 IRP, DEC did evaluate a construction cost sensitivity in which the costs to construct a new nuclear plant were (+20/- 10%) relative to the base case. DEC 2012 IRP at 106. DEC stated that the range used for the sensitivity analysis was based on the experiences of the Westinghouse/Shaw EPC consortium at Plant Vogtle, V.C. Summer, and the four AP1000 units currently under construction in China, "as well as the recent trend in industry data of lower escalation rates."[117] Notably, none of these experiences reflect an operational facility. Based on the complexity of nuclear plant construction, the history of significant cost overruns at nuclear plants (which in many cases greatly exceeded 20%), and the lack of recent data on U.S. nuclear construction, the (+20/- 10%) range may be overly narrow. Indeed, former Duke Energy Chief Operating Officer and Group Executive Vice President James Turner noted that it is not unreasonable for DEC to

[117] DEC Response to Informal Data Request No. 19.

assume and plan for significant cost overruns, in the 40-50% range, for its proposed Lee units.[118]

Neither DEC nor DEP ran a nuclear construction cost sensitivity analysis for the 2013 IRP updates. For their 2014 IRPs, both DEC and DEP should use broader, more conservative nuclear capital cost sensitivity ranges in their quantitative analyses that take into account the significant uncertainties and risks associated with nuclear construction.

VII. THE COMPANIES' REVISED RESERVE MARGINS APPEAR REASONABLE, BUT DEC'S MARGIN MAY STILL BE TOO HIGH IN LIGHT OF ITS TREATMENT OF DEMAND RESPONSE.

For 2013, DEC has lowered its reserve margin from 15.5% to 14.5%, based on the same reserve margin study conducted by Astrape Consulting, LLC that it relied upon in 2012 as well as to align its reserve margin with DEP's (unchanged) 14.5% reserve margin, "to enhance consistency and communication regarding reserve targets." While the 14.5% reserve margin appears reasonable, Duke Energy's method of calculating it is not. The treatment of demand response in the DEC and DEP reserve margin calculations raises concerns that the companies may be planning for excessive reserves.[119]

In their reserve margin calculations, DEC and DEP treat demand response as a resource with its own reserve requirement, contrary to North American Electric Reliability Corporation ("NERC") definitions and guidance.[120] In its October 14, 2013 order on the 2012 utility IRPs, the NCUC stated that DEC "should consider demand

---

[118] See DEC Reply Comments, Docket No. E-100, Sub 128 (March 1, 2011) at 32.
[119] Demand response is sometimes referred to in IRPs using the normally more general term "demand side management."
[120] CCL and SACE have commented on DEC's improper calculation of its reserve margin in comments to the Commission on DEC's 2011 and 2012 IRPs. See Comments of CCL, SACE and Upstate Forever on Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan, Docket No. 2011-10-E (Oct. 31, 2011) at 10-11 and Comments of CCL, SACE and Upstate Forever on Duke Energy Carolinas, LLC's 2012 Integrated Resource Plan Docket No. 2012-10-E (Dec. 6, 2013) at 35-37.

response in programs that it is able to control or dispatch as adjustments to net internal demand, similar to DEP."[121] Both 2013 IRPs (which, to be fair, were filed just days after the NCUC's order) rely on the method previously used by DEC that was recently rejected by the NCUC.

Astrape conducted both the DEC and DEP reserve margin studies; however, the treatment of demand response—specifically whether it requires backstand reserves—in the studies differed. In the DEP study, demand response is treated as a load adjustment, which does not require its own reserve requirement. In the DEC study, demand response is treated as a resource option with its own reserve requirement, thereby increasing the reserve capacity.

To illustrate the problem with this method, it is possible to adjust the reserve margins of both DEC and DEP by treating demand response as a load adjustment consistent with NERC guidance and the NCUC's recent order. Using this approach, DEC's 2017 reserve margin was underestimated by about 102 MW, and DEP's by about 128 MW, or a total of about 230 MW; and slightly more in 2018.

For purposes of calculating reserve requirements, system generation resources (and net transactions with other systems) should be compared to net internal demand. As defined by NERC, net internal demand includes unrestricted, non-coincident peak adjusted for energy efficiency, diversity, stand-by demand, non-member load, ***and demand response***.[122] DEP's previous method of accounting for demand response by

[121] North Carolina Utilities Commission, Order Approving Integrated Resource Plans and REPS Compliance Plans, Docket No. E-100, Sub 137 (Oct. 14, 2013) at 20-21.
[122] NERC, *Reliability Assessment Guidebook*, Version 3.1 (August 2012).

adjusting load appears to be more consistent with NERC guidance than the method still used by DEC and now adopted by DEP.

In response to prior criticism of its methodology, DEC stated that some of its demand response programs "require either communication with the customer, customer acceptance at the time of peak, or the reliance on aging infrastructure," with these technical issues resulting in "less demand reduction than anticipated" and therefore necessitating backstand reserves.[123] NERC guidance supports consideration of these factors, indicating that demand response programs should be considered in net internal demand to the extent that they are dispatchable and controllable.[124]

DEC has also suggested that NERC guidance is effectively indifferent toward the two approaches.[125] Under NERC guidance, it can be appropriate to evaluate demand response as a resource, as we have previously noted and as DEC has correctly observed, most recently in drawing a false contrast with our actual position.[126]

NERC advises utilities to apply "various performance characteristics described using capacity, associated forced outage rates and temperature sensitivities."[127] In discussing when demand response should be evaluated as a load modifier, the NERC guidance explains, "[i]f the loads can be expected to be reduced with a high degree of certainty, this would be an appropriate modeling technique."[128] In summary, NERC guidance encourages utilities to look at program-specific data in determining which approach to use. NERC guidance, in fact, favors the approach endorsed in the NCUC

---

[123] DEC Reply Comments on 2011 IRP, NCUC Docket No.E-100, Sub 128 (Jan. 27, 2012) at 14.
[124] NERC, *Reliability Assessment Guidebook*, Version 3.1 (August 2012) at 15.
[125] Rebuttal Testimony of Janice D. Hager, Docket No. 2013-392-E at 4.
[126] Duke's SC reply comments, p. 3.
[127] NERC, *Reliability Assessment Guidebook*, Version 3.1 (August 2012) at 14.
[128] Id.

order to the extent that demand response programs are dispatchable and controllable, and favors the approach that Duke Energy prefers when they are not.

While DEC claims that it has looked at program-specific data in making the determination as to the proper treatment of demand response programs, it has recently acknowledged that it has no actual data to offer in support of this claim. To the contrary, Duke Energy data actually indicate that both DEC and DEP demand response programs are dispatchable and controllable (except as discussed below). In fact, DEC reports that its demand response programs have been activated a number of times, and most programs have achieved reductions consistent with (or even in excess of) expected reductions.[129] DEC 2013 IRP at 80. Furthermore, although DEC's Vice President for Integrated Resource Planning and Analytics, Janice D. Hager, stated that demand response programs "are not 100% responsive" in testimony, Duke Energy conceded that Ms. Hager's statement "is not directly supported in Appendix D," and only supports her claim with conjecture regarding the behavior of customers and technology.[130] Thus, Duke Energy has acknowledged that it lacks data to support its contention that overall, DEC's demand response programs are not dispatchable and controllable. Indeed, Astrape modeled these resources without remarking on any technical issues that might suggest a backstand reserve requirement.[131] While technical issues may exist that result in less demand reduction achieved than expected, the activation history data do not suggest such issues are significant.

[129]The sole exception is the Power Manager (air conditioner) program, in which activation events since 2010 achieved 3-17% less reduction than expected.
[130] Response to SACE DR 2-2.
[131] For example, Astrape modeled various sensitivities reflecting general operational concerns affecting reserve margin planning, such as weather diversity. None of these sensitivities reflected general technical considerations related to the response of demand response resources.

More recently, DEC has provided new data from Astrape which DEC claims demonstrate that "there is virtually no difference" in the minimum required reserves needed regardless of how demand response resources are treated.[132] However, it is impossible to interpret these data because Duke Energy provided no information regarding whether Astrape assumed that technical issues impaired the dispatchability of demand response resources. DEC claims not to have in its possession any information regarding the method that Astrape used to calculate the findings in the information relied upon by DEC.

> The table included at the top of page seven of Janice Hager's rebuttal testimony filed in PSCSC Docket No. 2013-392-E shows target reserve margins with demand response programs included as resources and included as reductions to load. This table was provided by Astrape and there are no other reports or communications regarding this comparison.[133]

As discussed above, DEC has asserted that technical issues impair the dispatchable and controllable nature of its demand response programs, but it has not substantiated this assertion. In fact, DEP has previously planned as if its programs could be relied upon. It appears that Astrape's analysis relied upon DEC's unsubstantiated position that operation of demand response programs result in "less demand reduction than anticipated," [134] and thus does not lend credibility to DEC's arguments.

In summary, with the exception of the DEC PowerManager (air conditioner) program, Duke Energy should evaluate demand response programs for purposes of calculating reserve requirements as adjustments to net internal demand. This would align

---

[132] Rebuttal Testimony of Janice D. Hager, Docket No. 2013-392-E at 7. See also Duke's SC reply comments, p. 4-6.
[133] Duke Energy Carolinas and Duke Energy Progress, Response to SACE Data Request 2 (E-100, Sub 137), Item No. 2-3 (March 5, 2014).
[134] DEC Reply Comments on 2011 IRP, NCUC Docket No.E-100, Sub 128 (Jan. 27, 2012) at 14. See also Duke Energy's Response to SACE DR 2-2, and DEC's Reply Comments on 2013 IRP in SCPSC, p. 4.

DEC and DEP with the most straightforward interpretation of NERC guidance.[135] With respect to the recent performance of its air conditioner demand response program only, its recent performance suggests that DEC should either model the program as a resource (which would require average backstand of 14.5%) or adjust the expected reduction to reflect the results of recent activations.

An additional, related issue is that it is unclear whether DEC adjusts net internal demand to account for its demand response programs that use rate signals to reduce on-peak energy use, such as Residential Time-of-Use and Hourly Pricing for Incremental Load. DEC 2013 IRP at 86. These programs are not included in the reserve margin calculation (see Tables 8C and 8D). Id. at 29-32. They may be accounted for in other aspects of the load forecast, but if so, this is not described in the IRP. If the load impacts of these programs are significant, but not accounted for in the load forecast, then DEC should account for these resources in future IRPs to the extent that it would result in a significant impact on capacity requirements.

VIII. CONCLUSION

In light of the flaws discussed in the previous sections, the DEC and DEP 2013 IRPs present preferred plans that are unnecessarily costly, risky, and polluting. To correct these flaws and minimize costs and risks to ratepayers, DEC and DEP should implement the following improvements:

[135] PJM is another example of a utility system that calculates its reserve margin after subtracting energy efficiency and demand response resources. See, e.g., Summer 2012 PJM Reliability Assessment presented to Pennsylvania Public Utility Commission (June 7, 2012) at 4-5, available at http://www.puc.state.pa.us/electric/pdf/Reliability/Summer_Reliability_2012-PJM.pdf.

- The companies should include higher levels of energy efficiency on par with those of leading utilities in their preferred "Base Case" plans, and should evaluate energy efficiency as a resource that competes on its own merits with supply-side resources.

- The companies should explicitly recognize and incorporate the benefits that renewable energy resources provide in addition to capacity and energy, including hedging against fuel cost and environmental compliance cost risks.

- DEC and DEP should each conduct, and explicitly address in their IRPs, a rigorous evaluation of the economics of continuing to operate scrubbed coal units.

- DEC should eliminate the requirement of backstand reserves for demand response, which could reduce its reserve margin and avoid the need for excess generating capacity and unnecessary costs to ratepayers.

- Each company should conduct a more complete evaluation of the risks of construction delays and cost increases associated with new nuclear generation.

Remedying these flaws will help DEC and DEP to fulfill the objectives of the IRP process and provide the Commission and the ratepaying public with a complete understanding of the costs, risks and impacts of their resource plans.

Respectfully submitted this 11th day of April, 2014.

s/ Gudrun Thompson
Gudrun Thompson
N.C. Bar No. 28829
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, NC 27516
Telephone: (919) 967-1450
Fax: (919) 929-9421
gthompson@selcnc.org

Attorney for Southern Alliance for Clean Energy and the Sierra Club

CERTIFICATE OF SERVICE

I certify that the persons on the service list have been served with the foregoing Initial Comments of Sierra Club and Southern Alliance for Clean Energy either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This 11th day of April, 2014.

s/ Robin G. Dunn