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March 2, 2015

<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: In the Matter of: 2014 Integrated Resource Plans and Related 2014 REPS Compliance Plans; ***Docket No. E-100, Sub 141***

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 Southern Alliance for Clean Energy and the Sierra Club*. 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.

- **Public Version** of *Initial Comments of Southern Alliance for Clean Energy and the Sierra Club.* Confidential information in this document has been redacted and can be made available to the public.

By copy of this letter, I am serving a copy of the Public Version of the Comments on all parties of record. Copies of the Confidential Version will be provided 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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 141

In the Matter of:	)	
	)	INITIAL COMMENTS OF
2014 Biennial Integrated Resource	)	SOUTHERN ALLIANCE FOR CLEAN
Plans and Related 2014 REPS	)	ENERGY AND THE SIERRA CLUB
Compliance Plans	)	
	)	

Pursuant to North Carolina Utilities Commission Rule R8-60(j) and the Commission's September 29, 2014 order in this docket, Southern Alliance for Clean Energy ("SACE") and the Sierra Club, through counsel, hereby submit their initial comments in the above-captioned docket concerning the 2014 Integrated Resource Plans ("IRPs"). These comments focus on the 2014 IRPs filed by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, Inc. ("DEP") (together, "the Companies") on September 2, 2014.[1]

I. SUMMARY

The 2014 IRPs contain limited improvements upon the Companies' previous IRPs, but unfortunately, they retain most of the flaws of earlier IRPs. In addition, new assumptions and methods compound the flaws carried over from previous plans, resulting in resource plans that are more costly, more risky, and more polluting than necessary. Key flaws in the 2014 IRPs include the following:

- The Companies are planning to build too much capacity, while underinvesting in resources that would reduce system costs for all customers.

[1] These comments were prepared with supporting analysis and/or review by John D. Wilson and Natalie Mims at SACE, Bridget Lee and Kelly Martin at the Sierra Club, and Kenneth Sercy at the South Carolina Coastal Conservation League.

- The Companies do not appear to have evaluated the full range of costs to achieve and maintain compliance with environmental regulations at their coal-fired power plants. For some units, accelerated retirement may be the most economic option.

- As in prior IRPs, the Companies are not planning to capture all cost-effective energy efficiency, the cheapest, cleanest resource. This means system costs for ratepayers will be significantly higher than they need to be.

- The Companies do not plan to maximize cost-effective renewable energy opportunities that reduce risks to customers from rising fuel costs and anticipated regulatory requirements.

II. FRAMEWORK FOR INTEGRATED RESOURCE PLANNING

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).

As discussed in detail in the following sections, the Companies' IRP analyses suffer from numerous flaws that, taken together, result in resource mixes that are more costly, more risky, and have greater environmental impacts than necessary. To fulfill the objectives of the IRP process, DEC and DEP must cure the deficiencies of their analyses to provide the Commission and the public with a complete understanding of the costs, risks and impacts of their IRPs.

III. THE COMPANIES' QUANTITATIVE ANALYSES DO NOT RESULT IN THE LEAST-COST, LEAST-RISK PLANS.

In developing their 2014 IRPs, the Companies did not give full and fair consideration to cost-effective energy efficiency and renewable energy resources as alternatives to traditional supply-side resources. As a result, the 2014 IRPs are not least-cost, least-risk plans.

In our comments on the 2013 IRPs, we recommended that DEC and DEP should, among other things:

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

These recommendations remain valid with respect to the 2014 IRPs.

Although DEC and DEP each evaluated portfolios containing higher levels of energy efficiency and renewable energy, the results of this analysis were marred by the continuing use of unreasonable, biased assumptions and practices described in our comments on the 2013 IRPs. The most glaring problems that remain unaddressed are:

- The continued use of excessively high energy efficiency cost estimates, particularly for the High EE/Renewables Case;
- The continued use of excessively high solar and wind power cost estimates; and
- The failure to evaluate potential additional capital and operating costs that may be necessary to achieve and maintain compliance with forthcoming environmental regulations at the Companies' coal-fired power plants.

The results of the portfolio analysis are also suspect because DEC and DEP each selected a 50-year evaluation period to favor nuclear power resources, while modeling a phase-out of energy efficiency that ends after about 15 years.

A. Neither Company Has Conducted an Even-Handed Analysis of the Risks of Each Resource.

As discussed in comments on previous IRPs, the Companies use inconsistent criteria to evaluate the risks associated with each resource, using criteria that provide support for favored resources while applying different criteria or analytic methods to undervalue energy efficiency and renewable energy. The concerns we raised in prior comments with respect to the Companies' inconsistent consideration of risk are only magnified in the 2014 IRPs. The ever-changing criteria for evaluation seem to track the changing economics of DEC's proposed Lee nuclear plant. In the 2014 IRPs, DEC has selected a portfolio that includes 3,351 megawatts ("MW") of nuclear over the next 20 years, and DEP has selected a portfolio that includes 1,117 MW of nuclear over the next 20 years. The purported cost advantage of each of these portfolios over others is just a few percentage points, and relies upon excessively high assumptions regarding the cost of energy efficiency and renewable energy, as discussed below.

In addition, DEC and DEP have adopted new planning methods for the 2014 IRPs that mask the plans' risk of higher future costs for customers. Each of the 2014 IRPs is intended to plan for a "15 to 20 year planning horizon," DEC 2014 IRP at 58, DEP 2014 IRP at 59; however, each company has selected a 50-year period over which to analyze the long-term cost to customers of each portfolio (expressed as the present value of revenue requirements or "PVRR"). While the basis for this choice is not discussed in the 2014 IRPs, it appears that the Companies selected the 50-year study period to better suit the cost-recovery period for capital-intensive resources and justify the selection of a preferred portfolio including nuclear. As each company explained in its 2013 IRP, "[t]he PVRR results presented in the IRP analysis were based on a 15-year planning horizon, but the economics supporting new nuclear were extended to 2052 to capture the long-term benefits of the low production cost and carbon-free generation." DEC 2013 IRP at 50, DEP 2013 IRP at 46. In the 2014 IRPs, each Company extended the 40-year study period to 50 years. DEC 2014 IRP, Table A-3; DEP 2014 IRP, Table A-3.

One problem with the extended PVRR study period is that it fails to evaluate energy efficiency on an equivalent basis with other resources. As discussed in a later section, DEC's projection of EE impacts peaks in 2025, with new program impacts effectively eliminated by 2032; similarly, DEP's projection of EE impacts peaks around 2021, with new program impacts effectively eliminated by roughly 2028. Thus, for half of the PVRR study period, each company has excluded consideration of energy efficiency from its planning process. Like the costs of nuclear power, energy efficiency costs are primarily incurred during resource development, with low (or zero) production costs and carbon-free generation. By terminating the energy efficiency savings impacts halfway through the planning horizon, DEC and DEP constrain the quantitative analysis to select other, higher cost resources. In effect, the Companies are choosing to handicap energy efficiency in their scenario evaluation to limit its ability to compete with preferred, higher-return capital-intensive projects.

The other problem with the extended PVRR study period is that it creates risks for customers. Once new nuclear units are certified and construction begins, customers will pay for them regardless of whether there is a need for power or not. For example, Duke Energy Florida is recovering costs from customers for development of a nuclear reactor that has been cancelled and will never provide electricity to customers. Although this is an extreme case, it illustrates a very real risk that the 2014 IRPs do not discuss.

Like nuclear, solar and wind are low-production-cost, carbon-free generation resources. Yet when DEC or DEP has sought to purchase solar or wind power, it has used power purchase agreement ("PPA") contracting practices that unreasonably front-load development costs (as discussed in Section V.B., below). These practices stand in stark contrast to DEC and DEP's decision to extend the PVRR study period in the 2014 IRPs beyond the planning horizon in order to ensure that the "economics supporting new nuclear power" capture its benefits. When considering nuclear, the Companies look far into the future to evaluate benefits, but when considering renewable energy, they compress costs towards the present. This practice gives an unfair advantage to their preferred capital-intensive option of new nuclear.

This use of inconsistent criteria used to evaluate resources has very real consequences for the selection of a least-cost resource plan. While it is appropriate to evaluate costs over the long term, it does not provide the full perspective. A "head-to-head" evaluation over shorter periods should also be conducted to determine whether the benefits of some resources are mainly back-loaded and whether selecting those resources subjects customers to unacceptably high costs or risks during the planning horizon.

B. Energy Efficiency and Renewable Energy Cost Assumptions Are Unreasonably High.

The Companies have adopted unreasonably high cost estimates for energy efficiency, solar and wind that bias their PVRR analyses against these resources. As a result, the DEC and DEP 2014 IRPs fail to evaluate all resources, particularly clean energy resources, on an equal basis with other resources.

1. <u>Efficiency Cost Estimates</u>

In comments on the Companies' 2013 IRPs, we critiqued DEC's efficiency cost projections as excessive and flawed, for several reasons:

- DEC's long-term energy efficiency cost projection included costs incurred by program participants instead of limiting the costs to those paid by DEC.
- DEC assumed that for a more aggressive energy efficiency program, once low-cost measures reach a 60% market saturation, the program abruptly shifts to higher-cost measures.
- DEC limited the scope of its long-term forecast to 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.

- DEC assumed that costs would rise at an ever-increasing rate over the study period, disregarding evidence that economies of scale enable utility programs to scale up to higher levels of market penetration so that every dollar in program costs can achieve more savings. This trend is even evident in DEC's short-term program cost forecasts.

These flawed assumptions about energy efficiency costs are rooted in a misuse of certain assumptions in the Companies' 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*."[2]

Further, research contradicts the assumption that the cost of energy efficiency grows linearly with each additional kWh saved. The findings of a recent study by the American Council for an Energy Efficient Economy ("ACEEE"), in the words of the report authors, "cast doubt on the hypothesis that programs with higher electricity savings levels are associated with higher CSE values."[3] ACEEE data indicate that utility portfolios have achieved annual savings of 1.7% of retail sales at a cost of saved energy roughly equal to those reported by DEC and DEP. These findings are corroborated by a recent Lawrence Berkeley National Laboratory ("LBNL") report, which found that "the

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[2] Forefront Economics Inc. and H. Gil Peach & Associates LLC, Duke Energy Carolinas: Market Assessment and Action Plan for Electric DSM Programs North Carolina, Docket E-7, Sub 1032 (Feb. 2012) at 1 (emphasis added).
[3] Maggie Molina, The Best Value for America's Dollar: A National Review of the Cost of Utility Energy Efficiency Programs, American Council for an Energy-Efficient Economy ("ACEEE") (Mar. 2014), available at http://aceee.org/research-report/u1402 .

size of a program, as measured by the number of participants, is often, but not always, indirectly *associated with a decline in costs* for some program types."[4]

As with many flawed assumptions, there is a kernel of truth: energy efficiency program costs do eventually escalate—but only at much higher levels of energy efficiency than the modest levels that DEC and DEP are planning to achieve. For savings below 2.5% of annual sales, studies show either cost decreases or weak cost increases. For example, a study by Green Energy Economics Group indicates that program costs do not increase – and in fact decrease on a per unit savings basis – until savings reach 2.5% per year.[5] A 2008 report by Synapse Energy Economics concluded, "this analysis of actual program CSE [cost of saved energy] finds that program CSE seems to decrease as program scale and impact grows."[6] In a separate 2008 report on energy efficiency programs in Massachusetts, Synapse concluded, "the cost of saved energy could decrease if the utilities were to increase their program scale further, perhaps up to the level of annual savings equal to 2% or 3% of annual sales."[7]

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[4] G.L. Barbose, C.A. Goldman, I. M. Hoffman, M. A. Billingsley. The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025, LBNL-5803E, (Jan. 2013), available at http://emp.lbl.gov/publications/future-utility-customer-funded-energy-efficiency-programs-united-states-projected-spend. (Emphasis added).

[5] John Plunkett, Theodore Love and Francis Wyatt, Green Energy Economics Group, An Empirical Model for Predicting Electric Energy Efficiency Resource Acquisition Costs in North America: Analysis and Application (2012), available at http://www.aceee.org/files/proceedings/2012/data/papers/0193-000170.pdf.

[6] K. Takahashi and D. Nichols, The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date (2008), available at https://www.aceee.org/files/proceedings/2008/data/papers/8_434.pdf.

[7] Doug Hurley, Kenji Takahashi, Bruce Biewald, Jennifer Kallay, and Robin Maslowski, Synapse Energy Economics Inc. Costs and Benefits of Electric Utility Energy Efficiency in Massachusetts (August 2008) at 14.

For the 2014 IRPs, DEC and DEP appear to have aligned their long-term projections of energy efficiency costs,[8] but they have made substantial further changes to the cost forecasts:

- DEC has increased its Base Case projection of EE costs by 40-60%;
- DEC has increased its High EE/DSM Case projection of EE costs by 100-400%; and
- DEP has increased its High EE/DSM Case projection of EE costs by 60-80%.

The 2014 IRPs do not explain these dramatic increases that compound prior flawed assumptions about energy efficiency costs.

2. Renewable Energy Resource Costs.

With respect to renewable energy resources, the cost assumptions that the Companies used in their 2014 PVRR analyses diverge even more radically from reality than the assumptions used in the 2013 IRPs. As discussed below, the costs assumed are too high, and the assumed rate of escalation is at odds with reported cost *decreases*, which are projected to continue.

Regional and national experience and studies consistently show that DEC and DEP have adopted an unreasonably high projection for the cost of solar. While each company has reduced its solar cost projection slightly compared to the prior IRP, both assume that utility-scale solar will cost $2,186 per kW in 2016 (the first year in which solar may be selected for the capacity expansion plan) and increase by 2.5% per year

[8] With the exception of DEC costs for the High EE case beginning about 2022, for which costs increase substantially relative to those of DEP.

thereafter.[9] This assumption is not only inconsistent with other projections by DEC and DEP, as discussed in our comments on the 2013 IRPs, it is also inconsistent with more recent market data. For example, in October 2014, Georgia Power Company announced the selection of 515 MW of solar PPAs with in-service dates of 2015 and 2016; the "winning bids were procured at an average cost of less than 6.5 cents per kilowatt-hour."[10] The $2,186 per kW cost forecast used by DEC and DEP equates to roughly 7.4 cents per kilowatt-hour, or about 15% higher than the maximum price publicly disclosed by Georgia Power. Furthermore, the U.S. Department of Energy ("DOE") cost estimate for utility-scale solar photovoltaic ("PV") systems quoted in 2013 (for installation in 2014) is about $2,100 per kW, reflecting a 5% decrease in cost relative to the previous year.[11] Projected forward two years, the DOE trend appears to match the Georgia Power maximum price.

With respect to wind power costs, the Companies have actually increased the cost estimate assumed in the 2014 IRPs, while maintaining an excessive cost escalation rate. As discussed in our comments on the 2013 IRPs, the Companies' cost estimates for wind were higher than those reported by Lazard, a leading financial firm. In response to a data request related to the 2014 IRPs, Duke Energy provided two confidential proposals for wind energy projects in North Carolina. For one, the price quoted to Duke Energy for a [redacted]-year power purchase agreement was [redacted] per MWh ([redacted] per MWh with NC tax

[9] DEC and DEP, Response to SACE Data Request 1-1.
[10] Georgia Power Co., Application for the Certification of the 2015 and 2016 Advanced Solar Initiative Prime Power Purchase Agreements and Request for Approval of the 2015 Advanced Solar Initiative Power Purchase Agreements, Georgia Public Service Commission Docket No. 38877 (Oct. 10, 2014).
[11] U.S. Department of Energy, Photovoltaic System Pricing Trends: Historic, Recent and Near-Term Projections. Note that both figures are expressed in 2013 dollars.

benefits) with a [redacted]% annual escalation rate, which is [redacted] the range estimated by Lazard. The other utilized a [redacted] year contract term and [redacted] annual escalation rate, with a price of [redacted] per MWh. Considering the [redacted] terms, this price is [redacted] to that of the first project.[12] Although wind developers have encountered project-specific challenges and no wind PPAs have yet been executed in North Carolina, the project proposals illustrate the types of projects that could occur with active utility interest. These data demonstrate that the Companies are using unreasonably high cost assumptions for wind resources in their IRP modeling.

Finally, the Companies' capacity expansion modeling assumes that wind and solar costs will increase, even though solar and wind costs are rapidly declining. DEC and DEP did conduct sensitivity analyses that assumed 35% and 65% reductions in the cost of solar. A 35% reduction resulted in adoption of solar in the 2030 timeframe, and the 65% reductions resulted in adoption of solar "throughout the planning period." While these are large cost decreases, in fact, they are in line with the DOE trend cited above. Extrapolating the DOE-reported trend of annual 5% cost decreases, solar costs would decrease by 35% by 2020 and by 65% by 2028. As this simple analysis illustrates, the Companies' continued use of overpriced assumptions for renewable energy resource costs, as well as the overpriced forecast for energy efficiency program costs, have a substantial impact on the outcome of their resource planning.

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[12] DEC and DEP Confidential Response to SACE Data Request 2-6.

C. DEP's Analysis of the Economics of Its Coal Units Omits Costs Associated with Forthcoming Environmental Regulations.

In our comments on the DEC and DEP 2013 IRPs, we raised concerns about the apparent omission of compliance costs associated with forthcoming environmental regulations from the analysis of coal unit economics. DEC and DEP made several inconsistent, non-comprehensive responses to those comments, as discussed below. Neither DEC nor DEP has indicated in its 2014 IRP that it has updated assumptions regarding coal unit costs to reflect the cost of compliance with tightening environmental standards governing the inherently dirty process of burning coal for electricity.

1. Compliance Costs for Air Pollution Regulations.

In comments on the 2013 IRPs, we noted that for the vast majority of coal units, the DEC and DEP 2013 IRPs did not reflect a comprehensive evaluation of options for compliance with a suite of federal air pollution regulations, including but not limited to the Mercury and Air Toxics Standards ("MATS"), New Source Performance Standards for greenhouse gases under Section 111 of the Clean Air Act (the "Clean Power Plan," or "CPP") and the Cross-State Air Pollution Rule ("CSAPR"). This assertion was based on the Companies' response to a data request seeking "any analysis or assessment … of the economics, regulatory requirements, feasibility, or technology options related to continued operation, conversion, retirement or life extension of any of the companies' coal-fired generating units." The Companies responded, "No assessments have been completed by or for DEC and DEP since October 1, 2012 regarding continued operation, conversion, retirement or life extension of any of the Companies' coal-fired generating units."[13]

In their reply comments filed with the Public Service Commission of South Carolina ("PSCSC"), DEC and DEP did not dispute that they had not factored the cost of compliance with forthcoming environmental regulations into the resource planning process. In fact, they acknowledged that the "capital cost associated with future environmental control requirements were not considered in the filing of the 2013 IRP."[14] In defense of the decision to omit such costs in the IRP analysis, the Companies asserted that "it would have been ***imprudent*** to include large capital costs for compliance" in their IRPs.[15]

In contrast, in reply comments filed with this Commission, DEC and DEP put forth new information, commenting that "DEC and DEP believe that their remaining coal units are compliant with MATS and CSAPR," and that "Duke Energy has tested all coal units for compliance with MATS and compliance can be met without the installation of baghouses and with limited ACI injection at Allen and Marshall 4."[16] This statement appears inconsistent with the 2013 and 2014 IRPs, which stated 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 [North Carolina

[13] Duke Energy, Response to SACE Data Request 1-4, Docket No. E-100, Sub 137. In previous proceedings, we had made similar requests for earlier documents which also supported our conclusion.
[14] Duke Energy, Response to SACE Data Request 2-5, Docket No. E-100, Sub 137.
[15] Duke Energy Response to Comments by SACE, CCL and Upstate Forever on 2013 Integrated Resource Plan, PSCSC Docket Nos. 2013-8-E and 2013-10-E (March 12, 2014) ("SC Response to Comments") at 2. (Emphasis added).
[16] DEC and DEP Reply Comments, Docket No. E-100, Sub 137 (May 23, 2014) at 25.

Clean Smokestacks Act]." Compare DEC 2013 IRP at 105 with DEC 2014 IRP at 119; compare DEP 2013 IRP at 99 with DEP 2014 IRP at 113.

Any analysis of coal unit economics must also address compliance with the Clean Power Plan, released for comment in June 2014 and expected to be finalized in 2015. EPA has proposed the CPP to reduce carbon dioxide emissions from existing fossil-fueled power plants. As proposed, the CPP grants North Carolina regulators broad flexibility to design and adopt a plan for compliance, so the State can determine for itself which options for reducing emissions are feasible and cost-effective. Coal retirements are likely to be a cost-effective and sensible option for reducing carbon pollution. DEC and DEP should take a hard look at retiring their older, inefficient, polluting coal-fired units as they plan for CPP compliance.

We recommend that the Commission require DEC and DEP to clarify whether each company has actually identified and/or implemented any and all changes to coal unit operations required to comply with current and forthcoming air pollution regulations. The Companies should also clarify whether the cost estimates used in planning models have been updated to include all fixed and variable operating costs associated with these changes, as well as any associated future capital costs that may be reasonably anticipated, such as the cost of upgrades or overhauls. If not, we recommend that the Commission require the Companies to revise their IRPs to correct these deficiencies.

2. Compliance Costs for Water and Waste Regulations.

In our comments on the DEC and DEP 2013 IRPs, we raised similar concerns regarding several forthcoming water and waste regulations, including the Section 316(b)

Cooling Water Intake Rule, the Steam Electric Effluent Limitation Guidelines under the federal Clean Water Act, and coal combustion waste regulations.

DEC and DEP's reply comments to the PSCSC simply stated that including the costs of complying with these regulations would be "imprudent," as noted above. Their reply comments filed with this Commission differed, however: DEC and DEP asserted with respect to forthcoming water and waste regulations, that "based on the 316(b) rule finalized in May 2014, cooling towers are not anticipated to be required." Tellingly, while the Companies asserted that the Coal Asset Valuation Tool we relied upon to provide estimates of costs was "invalid and … must be disregarded," the Companies' comments limited their reply to "the Companies' expected outcome with Mercury Air Toxics Rule (MATS) and 316(b) requirements." The Companies' response thus specifically omitted any rebuttal to cost estimates associated with forthcoming effluent guidelines and coal combustion waste handling and disposal regulations.

Compliance with water and waste regulations will likely require significant capital investments and/or increased operating costs at the Companies' coal units. For example, DEP has not yet converted the Asheville coal plant to dry ash handling. DEP has not provided an estimate of the cost for the Asheville plant to achieve and maintain compliance with environmental requirements; however, in our 2014 comments, we estimated the cost at about $1,300 per kW—substantially greater than the approximately $1,000 per kW cost of a new combined cycle natural gas plant, a useful point of comparison. Further, continued generation of coal ash at the Asheville plant will require investment in additional long-term disposal for coal ash after the current ash disposal/fill project at the Asheville airport reaches capacity—which is expected to occur before the currently projected retirement date for the Asheville plant. Finally, the Asheville plant is currently awaiting a renewal of its National Pollutant Discharge Elimination System permit and associated variance for its discharge of heated wastewater in excess of water quality standards at Lake Julian. Because Lake Julian is one of the warmest lakes in the state of North Carolina, DEP may well have to invest in cooling towers to bring the Asheville plant into compliance with applicable standards.

These high compliance costs should be evaluated in comparison to alternatives. A promising alternative is retirement of the Asheville plant, coupled with a transmission solution to connect the Asheville-area “load pocket” with the rest of the jointly dispatched DEC-DEP system. Duke Energy has evaluated the potential to construct a 230 kV transmission line, along with related upgrades and other mitigation, to support the transmission of 600 MW of power to Asheville. The cost for this project is estimated by Duke Energy to be $172.6 million, which represents about $288 per kW of transmission capacity enhancement.[17]

Based on their reply comments and the current IRPs it appears that the Companies did not factor into their quantitative analyses cost estimates associated with forthcoming effluent guidelines and coal combustion waste handling and disposal regulations. If so, we recommend that the Commission require the Companies to take the following steps:

- DEC and DEP should provide their current estimate of these costs for each unit or plant potentially affected by the regulations, including capital, fixed O&M, and

[17] DEC, Evaluation of Annual Firm Transmission Reservation Request 794866047 (undated, but filestamped to October 2014).

variable O&M, along with any impact on plant operating efficiency that would affect heat rates or other plant efficiency measures;

- If DEC or DEP has conducted an analysis of whether it is more economic to retrofit or retire coal units, it should describe the results of this analysis, explain whether it only covers compliance with expected future regulations, and explain whether it was conducted prior to any recent investments to maintain plant availability on the Companies' systems;
- If DEC or DEP has not conducted such a "retrofit versus retire" analysis, it should conduct such an analysis or explain why one should not be conducted; and
- DEC and DEP should ensure that future IRPs reflect accurately the status of the Companies' analyses of cost estimates, the scope of such analyses, and schedules for refining those cost estimates.

3. <u>Duke Energy's Statements to Regulatory Commissions Contrast with Statements Made to the Financial Community.</u>

Contrary to the Companies' assertions that it would be "imprudent" to plan in advance to avoid, rather than incur, environmental compliance (or cleanup) costs, it is the *exclusion* of future environmental costs from the IRP analysis that is imprudent. The Companies' 2014 IRPs filed with this Commission and the PSCSC stand in stark contrast to statements made to financial analysts, in which their parent company Duke Energy acknowledges billions of dollars in looming environmental costs. In its "Earnings Review and Business Update," for the third quarter of 2014, Duke Energy estimated $3 billion in environmental compliance expenditures (or "investments") in the Carolinas, [18] including a potential "$400 - $500 million" in capital expenditures on cooling water towers or intake structures.[19] As with the 2013 IRP, these capital costs appear to be absent from the 2014 IRP analysis.

Despite its failure to plan for the costs of environmental compliance—or better yet, plan to avoid or minimize them—Duke Energy expects that the customers of its Carolinas operating utilities will bear these costs. During a 2014 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 environmental recovery" in the Carolinas.[20] 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 the IRP analysis would be "imprudent" flies in the face of responsible resource planning, which 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.

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[18] Duke Energy, "Earnings Review and Business Update: Third Quarter 2014" (Nov. 5, 2014) at 30, available at: http://www.duke-energy.com/pdfs/3Q2014Slides.pdf
[19] Id. at 37.
[20] Duke Energy, Transcript of Q4 2013 Duke Energy Corporation Earnings Conference call (Feb. 18, 2014) at 18-19.

4. Duke Energy Should Consider Accelerated Retirement of the Allen and Asheville Coal Plants.

In the past, the Companies have asserted that the economic value of coal units is related to their operation at high capacity factors. As shown in their Power Plant Performance Reports filed with the Commission, however, many of the Companies' remaining coal plants are operating at low capacity factors. This trend is likely to continue. The DEC and DEP Base Cases indicate that the capacity factors of the Companies' coal fleets will [redacted] from [redacted] in 2015 to [redacted] in 2028.

Despite this apparent trend, DEC and DEP are planning to retire very few coal units over the planning horizon. Based on depreciation book life, DEC projects retiring Allen Steam Station in 2028 and DEP projects retiring its Asheville and Roxboro plants in 2031 and 2032, respectively. DEC IRP at 50, DEP IRP at 48. It may be economic to retire at least the Allen and Asheville plants much sooner, however—these plants stand out as having [redacted] projected capacity factors, as illustrated in confidential Figure 1, below.

Figure 1: Projected Capacity Factors, Duke Energy's Carolinas Coal Fleet
[[redacted]

[redacted]

Source: Duke Energy Response to SACE's Fifth Data Request.

As shown in confidential Figure 1, above:

- The capacity factor of the Allen Plant (Units 1-5) is projected to [redacted] from [redacted] in 2015 to [redacted] in 2028. Even in a scenario without carbon costs, the capacity factor at the Allen Plant [redacted] from [redacted] in 2023 to [redacted] in 2028. It also appears that the plant [redacted] in 2029 in both scenarios.
- The capacity factor of the Asheville Plant (Units 1 &2) is projected to [redacted] from [redacted] in 2015 [redacted] in 2028. Even without carbon costs, the Asheville Plant's capacity factor is projected to [redacted] from [redacted]% in 2015 to [redacted] in 2028. This is a marked change from the prior IRP, in which DEP projected the capacity factor at Asheville Plant to [redacted] throughout the forecast period.

- In contrast, the average capacity factor across the rest of the combined DEC and DEP coal fleet is projected to be significantly [redacted] than at either the Allen or Asheville plant over the planning horizon, whether carbon costs are assumed or not.

Based on these data, the Commission should question the cost-effectiveness of continued investment in maintenance and upgrades of the Allen and Asheville plants for the purpose of keeping the units in operation.

In addition, Allen Units 1 and 2 are subject to a long-pending federal Clean Air Act New Source Review ("NSR") enforcement action for alleged unlawful modifications. Of the multiple coal units subject to the NSR enforcement case against Duke Energy, Allen Units 1 and 2 are the only ones still operating and emitting pollutants. Furthermore, DEC is now required to invest in the costs of dry ash handling for bottom ash at Allen. Accelerated retirement of all five of the Allen units would reduce environmental compliance costs and risk to ratepayers, and speeding up the retirement of Allen Units 1 and 2, in particular, would also reduce the risk to shareholders posed by the ongoing NSR litigation.

IV. THE COMPANIES HAVE NOT FAIRLY EVALUATED ENERGY EFFICIENCY AND ARE THEREFORE PLANNING TO BUILD EXCESS CAPACITY.

As in prior IRPs, the 2014 IRPs show that DEC and DEP are not planning to capture all cost-effective energy efficiency, the cheapest, cleanest resource. Energy efficiency (or "EE") has been deployed successfully across the United States to reduce risk and energy bills for consumers. Successful EE programs lower the system costs of providing electricity to all customers and reduce participant utility bills.[21] Energy efficiency also reduces environmental impacts and compliance costs, conserves water, reduces energy market prices, lowers portfolio risk, promotes local economic development and job growth, and assists low and fixed income populations.[22] Nor are low rates a deterrent to cost-effective efficiency gains. Several states with leading EE programs have electricity rates comparable to, or even lower than, rates in North Carolina, as shown in Table 1, below.

Table 1: Electricity Rates[23] and ACEEE State Rankings

	Residential	Commercial	Industrial	ACEEE State Ranking
North Carolina	*11.59*	*8.80*	*6.53*	*24*
Oregon	**10.72**	**8.75**	**6.32**	3
Washington	**8.95**	**7.85**	**4.54**	8
Illinois	11.65	8.88	**6.39**	11
Iowa	12.25	9.63	**5.24**	14
Arkansas[24]	**10.17**	**8.22**	**6.29**	31

If DEC and DEP incorporate all cost-effective energy efficiency into their IRPs, they will defer or avoid planned new generation—and the costs and risks that it represents for customers.

[21] See Direct Testimony of Timothy J. Duff, Docket No. E-7, Sub 1032 at 13.
[22] Note 1. See also Analyzing and Managing Bill Impacts of Energy Efficiency Programs: Principles and Recommendations, Utility Motivation and Energy Efficiency Working Group, State and Local Energy Efficiency Action Network (July 2011) at 6, note 4, available at http://www1.eere.energy.gov/seeaction/pdfs/ratepayer_efficiency_billimpacts.pdf.
[23] U.S. Energy Information Administration, Electric Power Monthly. Table 5.6.A, Average Retail Price of Electricity to Ultimate Customers by End-Use Sector (Nov.2014), available at http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a
[24] Arkansas is included in this table because while it has a lower ACEEE ranking, utilities in the state saved comparable amounts of efficiency (0.49% of sales in 2013 for Arkansas, 0.55% of sales for North Carolina) despite lower electricity rates. It is also worth noting that Entergy Arkansas saved 0.9% of sales in 2013, achieving much higher savings than either DEC or DEP. In addition, the Arkansas Commission ordered that the electric utilities in Arkansas are required to increase their efficiency savings 0.9% in 2015, while using their existing 2014 budget and utility performance structure. Arkansas Public Service Commission, Order No. 15, Docket No. 13-002-U, (Feb 20, 2014) at 3, available at http://www.apscservices.info/pdf/13/13-002-u_157_1.pdf.

A. Increased Levels of Energy Efficiency Could Avoid or Defer Expensive New Generating Capacity.

In its 2014 IRP, DEC projects that its energy efficiency programs will reduce demand and load by about 7.6% of retail sales by 2022, or about 1,700 MW;[25] DEP projects energy savings of about 1,402 MW by 2022.[26] This adds up to over 3,100 MW of energy savings by the Companies. Achieving just this 3,100 MW of savings, as planned, will enable the Companies to avoid building the equivalent of roughly four large NGCC plants.

The Companies can and should achieve greater energy savings, however. Despite modest levels of efficiency savings, both DEC and DEP are planning to add large amounts of new generating capacity over the 15-year planning horizon. The 2014 DEC IRP shows that DEC is planning to build 3,509 MW of new conventional generating capacity, including converting one coal plant to natural gas this year (170 MW) and constructing one natural gas combustion turbine (792 MW), two NGCC units (1,536 total), and two new nuclear units in 2024 and 2026. DEC 2014 IRP at 36. DEP is planning to build 4,137 MW of new conventional generating capacity, including nuclear and gas uprates (171 MW), four natural gas combustion turbines (1,398 MW) and four NGCC plants (2,598 total). DEP 2014 IRP at 36. Together, DEC and DEP project 1,858 MW in "undesignated future resources" by 2020. DEC 2014 IRP at 32, DEP 2014 IRP at 32. Aggressive but achievable levels of energy efficiency would allow the Companies to defer or avoid building expensive new generating capacity.

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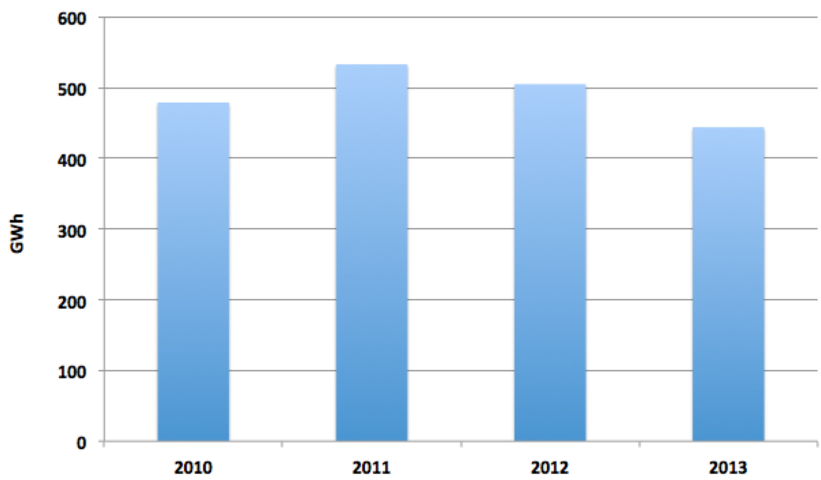
[25] Calculated by comparing projected 2022 gross EE impacts, DEC 2014 IRP at 102, to projected 2022 retail sales, DEC-DEP Response to Public Staff Data Request Item 1-9.
[26] Sum of Cumulative New EE Programs and Cumulative DSM Capacity in Table 8-B, DEP 2014 IRP.

In developing its 2014 IRP, however, neither DEC nor DEP selected an "optimum" level of energy efficiency. Each company modeled both a "Base Case" level of efficiency and a "High EE/Renewables" level that included more efficiency. Both levels were input as adjustments to the load forecast. This practice is biased against energy efficiency. The better practice is to allow the planning model to select energy efficiency, 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 energy efficiency as a resource, DEC and DEP have biased their resource planning process in favor of new generation. By achieving higher levels of energy efficiency—levels achieved by many utilities across the nation—DEC and DEP could defer and eventually avoid more of the planned generation capacity in their IRPs.

B. The DEC and DEP 2014 IRPs Project Declining Efficiency Savings.

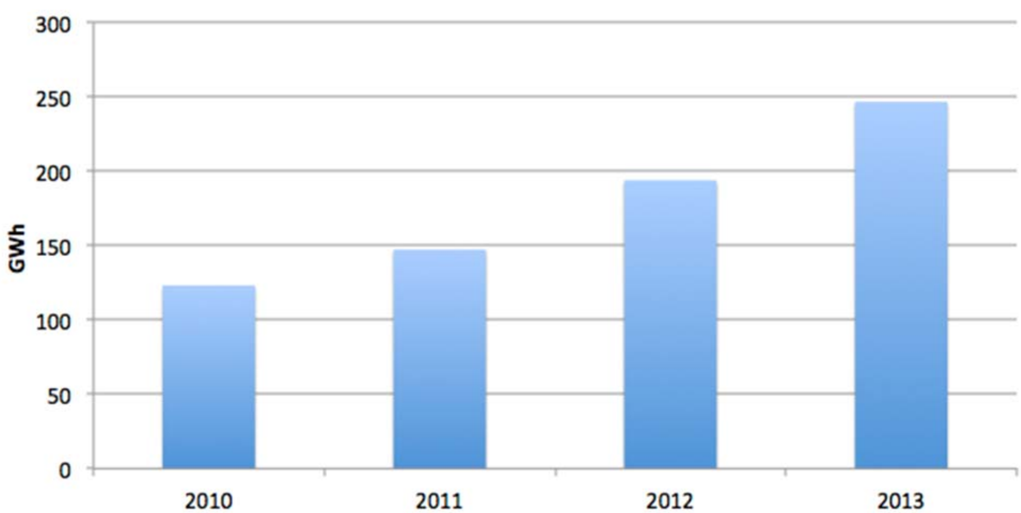
DEC's strong performance in its first few years of energy efficiency program implementation, in which it exceeded energy savings forecasts and effectively controlled program costs, demonstrates that energy efficiency is a dependable, economical resource. Despite this strong track record, DEC's EE savings have declined since 2011 in North Carolina, as shown in Figure 2, below.

Figure 2: Duke Energy Carolinas 2010-2013 Energy Efficiency Impacts[27]



In contrast, DEP's performance in its first few years of energy efficiency program implementation showed continuous growth from 2009-2013, as shown in Figure 3, below.

Figure 3: Duke Energy Progress Energy Efficiency Impacts, 2010-2013

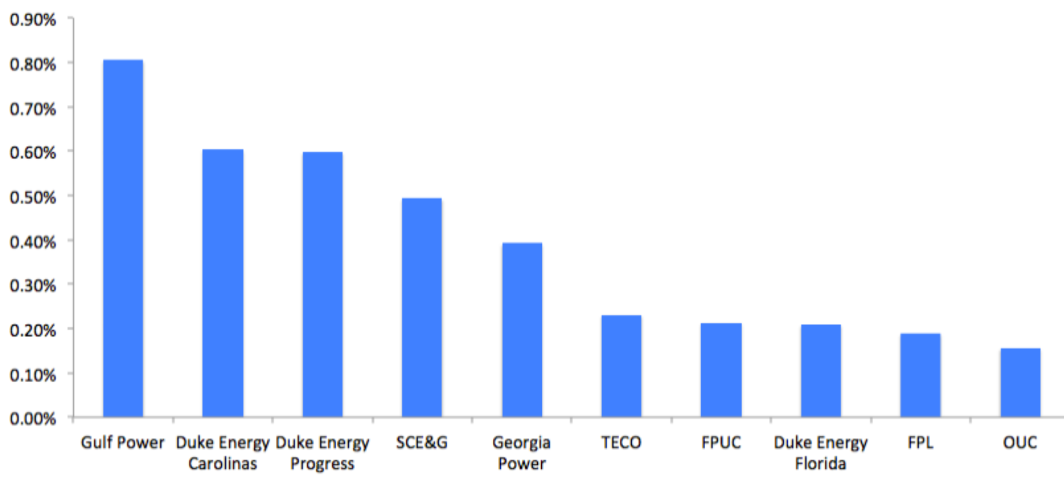


[27] Duff Exhibit 1 at 1-5, Docket E-7, Sub 1050.

Although it has ramped up its efficiency savings, DEP's energy efficiency performance has consistently been outpaced by that of DEC. While DEC led the Southeast in energy efficiency savings in 2011 and 2012, its status is beginning to slip: in 2013, DEC's savings of 0.60% of prior year retail sales was surpassed by Gulf Power's savings of 0.80% and by Arkansas utilities' savings of 0.75%.[28]

DEC's and DEP's 2013 efficiency savings are compared to those of their peer utilities in the Southeast in Figure 4, below.

Figure 4: Efficiency Impact as a Percentage of Retail Sales, 2013



[28] See Arkansas Public Service Commission, Docket 07-085-TF, available at http://www.apscservices.info/efilings/docket_search.asp.

Despite successful program delivery and improved efficiency forecasting, neither company's actual or projected savings reflect the level of savings that are being achieved by utilities in leading states, which are saving from 1.5-2% of their sales each year.[29] DEC projects that it will achieve between 8-15% cumulative energy savings, and DEP projects between 5-11% cumulative energy savings from energy efficiency programs by the end of the IRP planning horizon, as shown in Table 2, below.

Table 2: Projected Cumulative Energy Efficiency Savings as % of 2029 Sales

DEP		DEC	
Base Case Gross 2007 measures +	6%	Base Case Gross 2009 measures +	10%
Base Case Gross 2014 measures +	5%	Base Case Gross 2014 measures +	8%
High Case Gross 2007 measures +	11%	High Case Gross 2009 measures +	15%
High Case Gross 2014 measures +	10%	High Case Gross 2014 measures +	13%

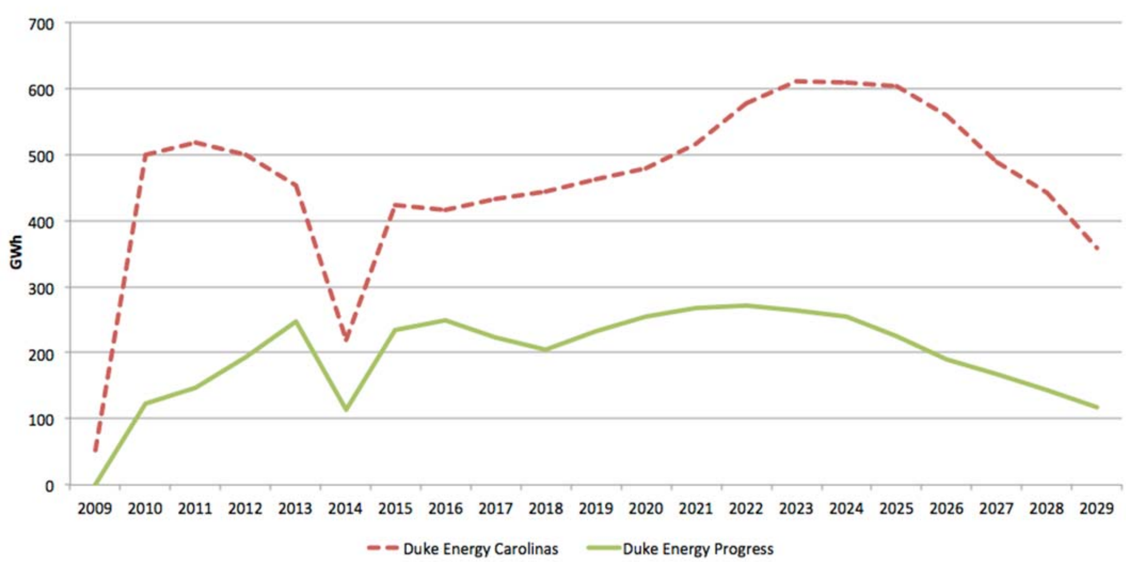
Further, each company's Base Case IRP savings forecast projects annual savings that are far less than 1% of sales per year. By contrast, the five-year EE performance targets set forth in the December 8, 2011 Settlement Agreement negotiated in connection with the Duke Energy-Progress Energy merger set forth savings of 7% over the 2014-2018 period, consistent with an annual rate of 1.4%.[30] DEC and DEP do not explain in their IRPs how they intend to meet the targets they agreed to. Indeed, based on the lack

[29] ACEEE, The 2014 State Energy Efficiency Scorecard (Oct. 22, 2014) available at http://aceee.org/research-report/u1408.
[30] In the PSCSC 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, 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 PSCSC in its Order Approving Joint Dispatch Agreement, Order 2012-517 (July 11, 2012) at 43.

of a detailed, concrete strategy to ramp up savings levels—by developing new programs, adding measures to existing programs, increasing customer participation, or other tactics—it appears that the Companies are not, in fact, planning to meet the targets. The Commission should ensure that the Companies expand and enhance their efficiency portfolios to meet the five-year EE performance targets set forth in the December 8, 2011 Settlement Agreement.

Both DEC's and DEP's projected EE savings are also inadequate because they do not plan for growth. DEC and DEP have already achieved energy savings impacts that are higher than the forecasted impacts in the Base EE/DSM Cases for 2014-2020. Figure 5, below, shows each company's actual energy savings impacts from 2010-2013 and projected impacts through 2038. As shown, each company projects that its long-term energy efficiency impacts will decline over time, despite the fact that emerging technologies and new efficiency measures are likely to become available in the future.

Figure 5: DEC and DEP Actual and Projected Base Case EE Impacts, 2009-2038



The Companies 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. In particular, for DEC and DEP to increase their energy savings beyond their Base Case projections and achieve the levels in the High Case, it will be crucial to attract participation from customers in the energy-intensive industrial and large commercial sectors.

C. DEP Has Made Positive Changes in Its 2014 IRP Regarding EE and DSM Program Forecasting.

The DEC and DEP 2014 IRPs reflect several improvements to the Companies' DSM/EE planning based on recommendations from the Public Staff.

The Public Staff's first three recommendations were the following:

- The investor owned utilities ("IOUs"), and in particular DEP and DEC, should develop a consistent method of evaluating their DSM and EE portfolios and incorporate the savings in a manner that provides a clearer understanding of the year-by-year changes occurring in the portfolios and their impact on the load forecast and resource plan in future IRPs. The savings impacts should be represented on a net basis, taking into account any net-to-gross impacts derived through EM&V processes.
- DEP and DEC should specifically identify the values of DSM and EE portfolio capacity and energy savings separately in its load forecast tables and not embed these values in the system peak load or energy.

- The IOUs should account for all of their DSM/EE savings from programs approved pursuant to G.S. 62-133.9 and Commission rule R8-68, regardless of when the measures were installed.[31]

In response, in their 2014 IRP DEC and DEP each provided four data sets for both the base and high energy efficiency case: gross and net savings, cumulative since 2007 and since 2014. The Base Case savings were included in the load forecast.

Finally, the Public Staff recommended that DEP and DEC "should adopt one methodology of evaluating the DSM and EE components of the IRP and remain consistent year-to-year… If an IOU determines that a change in methodology is required or appropriate, these changes should be thoroughly explained, justified, and reconciled to the savings projected in the previous IRP."[32] DEC and DEP responded that their methodology did not change from 2013 to 2014.

V. THE COMPANIES DID NOT PROPERLY CONSIDER RENEWABLE ENERGY RESOURCE OPPORTUNITIES.

A. The Companies Have Improved Their Analyses, but Further Improvements Are Needed in Order to Fully Capture the Value of Renewables.

Renewable energy resources such as solar and wind hold great potential for providing large amounts of clean, cost-effective power to DEC's and DEP's customers. The installed costs of both solar and wind have fallen over time and are expected to continue to fall. With continued declines, renewables will become least-cost resources—even when they are evaluated simply on the basis of the energy and capacity they provide

[31] Public Staff's 2013 IRP Comments, Docket E-100, Sub 137 (April 11, 2014) at 43-44.
[32] Id. at 44-45.

and their other system benefits are ignored. Yet solar and wind resources offer additional benefits to customers that likely make higher levels of these resources prudent additions to the Companies' IRPs. It is thus critical that DEC and DEP improve their consideration of solar, wind, and other renewables in resource planning, so that cost-effective opportunities to deploy these valuable resources are not overlooked.

In previous comments, we recommended that DEC and DEP evaluate one or more "High Renewables" and/or "High DSM/High Renewables" candidate portfolios across multiple sensitivities, as the Companies have done for years for nuclear- and gas-focused portfolios.[33] Each company has done that in the 2014 IRP, and this shift in approach is an encouraging improvement. The Companies' presentation of the results of their analysis ("Delta PVRR" tables) obscures the value of this approach, however.

Evaluating high renewables candidate portfolios across sensitivities allows the planner to assess the ability of low-risk renewable resources to provide cost stability to the portfolios across many possible futures. The "Delta PVRR" comparison metric used in the 2014 IRPs, however, obscures the absolute cost of each portfolio. As a result, it does not show how much costs are expected to vary across different possible futures. Additionally, the sensitivities included in this phase of the analysis were limited; for instance, capital cost sensitivities were assessed in a previous phase but left out of this phase. Finally, the IRPs do not clearly describe how the results of the portfolio analysis are used to choose the preferred portfolio. Each IRP contains a discussion that

[33] For the 2013 IRP, DEC and DEP evaluated an "Environmental Focus Scenario" that incorporated higher levels of energy efficiency and renewable energy; however, it was a single, isolated scenario with fixed assumptions regarding fuel price, carbon price, etc., as opposed to a High EE/RE portfolio that is tested in multiple model runs having different assumptions about regarding fuel price, carbon price and other variables.

emphasizes CO_2 concerns, but this limited discussion does not clearly explain the criteria used to evaluate the PVRR results over the range of scenarios and sensitivities tested.

The Companies' evaluation of high renewables candidate portfolios is a positive development that should be retained in future analyses, but further improvements are needed before the Commission and interested parties can accurately assess the plan selected on the basis of the portfolio modeling results.

B. The Companies Should Implement Best Practices in Modeling and Procuring Solar Resources.

1. DEC and DEP have lagged in incorporating best practices for modeling solar technologies.

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. In previous comments, we highlighted selected best practices for considering solar within resource planning, based on recent industry literature. For example:

- **Analyze and assign appropriate capacity values to solar resources.** "Capacity value" is the value of the contribution of solar technologies to satisfying peak demand requirements, and can vary by solar technology, system location, geographic diversity of systems overall, solar coincidence with load, and other factors. DEC appears to have used capacity values of 42% in its 2013 IRP and 46% in its 2014 IRP; DEP appears to have used capacity values of 42% in its 2013 IRP and 44% in its 2014 IRP. These capacity values are generally consistent with those used by other U.S. utilities, but this topic is an area of continuing methodological development within the industry that merits ongoing attention. To date, neither company has discussed in an IRP the methodology it uses to derive solar resource capacity value, or why its estimates have changed from year to year.

- **Evaluate whether to treat distributed generation as a resource or as a reduction to load.** For the 2013 IRPs, DEC and DEP included projections of customer-owned solar distributed generation ("DG") in their load forecasts, and the Companies appear to have continued this practice for the 2014 IRPs. As in the 2013 IRPs, the DEC and DEP 2014 IRPs appear to treat residential solar DG as a reduction to load. However, DG can also be treated as a supply-side resource that competes with other supply- and demand-side resources within the planning process and is included in one or more candidate portfolios that are modeled and compared on a PVRR basis. DEC and DEP should include DG as a resource option in their IRPs, and should appropriately value the range of impacts that DG may have on the jointly dispatched DEC-DEP systems.
- **Capture distribution system impacts of DG and other technologies/activities in long-term plans.** Distributed solar can have varied impacts on utility distribution systems, yet DEC and DEP do not appear to consider these impacts within the IRPs. For example, 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. [34]

[34] R. Thomas Beach & Patrick G. McGuire, The Benefits and Costs of Solar Generation for Electric

The above points illustrate ways to integrate evolving best practices for modeling solar resources into long-term resource planning. In previous comments, we requested that the Commission initiate a review of best practices for modeling utility-scale and distributed solar technologies in resource planning. We renew that request here. This review could occur within an IRP docket or in a separate proceeding. The Commission could then direct the utilities to adopt the identified best practices and revisit the topic periodically to ensure that utility modeling and decision-making processes reflect current industry conditions and analytical methodologies.

2. The Companies' solar procurement should reflect national best practices.

DEC and DEP have completed a jointly issued RFP for solar in North Carolina[35] and, as discussed above, Georgia Power has completed a solar RFP in Georgia.[36] However, the terms and the results of these RFPs were markedly different:

- Georgia Power's RFP resulted in prices below 6.5 cents per kWh, well below the benchmark avoided cost. DEC and DEP did not disclose publicly any price figures, but did indicate that there would be an incremental cost above avoided costs.
- Georgia Power's RFP "considered all proposals including those offering any and all financial structures, and bids with terms ranging from fifteen

Ratepayers in North Carolina (Oct. 18, 2013).

[35] DEP, DD Fayetteville Solar NC, LLC and Duke Energy Progress, Inc.'s Joint Notice and Request for Approval to Transfer Certificate of Public Necessity and Convenience, Docket E-2, Sub 1054 (Sept. 23, 2014).

[36] Georgia Power Co., Application for the Certification of the 2015 and 2016 Advanced Solar Initiative Prime Power Purchase Agreements and Request for Approval of the 2015 Advanced Solar Initiative Power Purchase Agreements, Georgia Public Service Commission Docket No. 38877 (Oct.10, 2014).

to thirty years." DEC and DEP, by contrast, "solicited proposals for PPAs (durations not to exceed a 15-year term) and asset purchase proposals … limited to projects that had filed interconnection requests … at the time of the issuance of the RFP."

- Georgia Power's RFP resulted in offers for "5,100 MW through 142 unique proposals from 56 different bidders." The financial structures of the proposals were not disclosed, but all winning bids were PPAs. DEC and DEP's RFP resulted in offers for 817 MW through 23 unique proposals from 10 different bidders. Utility ownership was proposed in 16 bids, and seven bids proposed PPAs. The Companies elected to purchase 128 MW across three projects and signed PPAs for 150 MW from five projects.
- Georgia Power's RFP leveraged the federal Investment Tax Credit ("ITC") by establishing a 2016 deadline. DEC and DEP's RFP set an earlier 2015 deadline to also leverage the North Carolina Energy Tax Credit ("ETC").

Based on the publicly available information, it appears that in spite of the benefit of the North Carolina tax credit, Georgia Power's RFP received more developer interest and lower prices. While the RFP issued by DEC and DEP is outside the immediate scope of this proceeding, it raises the question whether the Companies' planning and resource procurement practices are resulting in unnecessarily high prices for solar power.

One of the key differences between the Georgia and North Carolina RFPs is the limitations on the length of PPA contracts. DEC and DEP may argue that short-term contracts for solar PPAs protects customers in that they ensure that customers will not be "overpaying" for power at some future date if avoided costs decline. This reasoning is misguided in three respects:

- By limiting contracts to 15 years (a period shorter than the average useful life of a solar facility), the Companies may have spurred solar developers to offer higher prices in an effort to recoup their investment over the contract period. This would inflate the cost of solar PPAs both absolutely and relative to other resources evaluated in the IRP. By contrast, the Companies use longer time horizons to evaluate other resources, such as nuclear, which exposes customers to the risk of construction cost overruns.
- For contracts that do not include a renewable energy certificate ("REC") purchase, DEC and DEP only consider solar projects that are at or below avoided cost. In setting this strict limit, DEC and DEP are exposing customers to the very real risk that natural gas prices will increase beyond its current forecast, driving up fuel costs which are passed directly through to customers. Locking in longer term, lower price contracts for fuel-free solar power (or owning the projects outright) will protect customers from the risk of fuel price increases. The risk mitigation value of solar contracts is a quantifiable value that should be explicitly considered in resource planning and procurement.

The relatively strong performance of utility ownership proposals in North Carolina, compared to the prevalence of 20-, 25- and 30-year PPA contracts in Georgia, is also telling. The North Carolina RFP results suggest that solar developers recognized that 15-year PPAs would be at a disadvantage compared to utility-owned assets. This disadvantage is evident from the method used by DEC and DEP to evaluate the proposals.

As described in a recent filing by DEP, the Companies evaluated "PPA and utility ownership proposals on a comparable basis to indicate relative value to customers for REPS compliance purposes … [using] a 25-year study period." For PPAs, the study period used "submitted bid pricing for years 1 – 15 of the study period," but for the final 10 years, the PPAs were valued using an "escalated" avoided cost of energy plus a "nominal REC value." In contrast, the asset purchase proposals were converted into an annual revenue requirement for the 25-year study period. This methodology puts PPAs at a clear disadvantage because it forces the developer to choose between pricing a bid to recover the construction costs in the first 15 years of the project's 25-year lifetime (effectively "front-loading" the costs), or to price a bid at a level that does not assure cost recovery over the contract term, and thereby assume the risk of not recovering the remaining costs after the 15-year PPA period ends. In contrast, developers proposing utility ownership assume no risk. Whether the PPA is priced to assume full recovery of construction costs in 15 years or to include a risk premium, it is unlikely that solar developers can price their products on a basis consistent with lifetime cost analysis. Essentially, the PPA terms result in overpriced bids relative to actual cost, making solar PPAs seem less cost-competitive with other resources.

While the Companies may evaluate solar resources over a 25-year study period, as described above, their contracting and procurement practice results in front-loading the costs of renewable energy resources, which in turn artificially drives up the price of those resources. This is inconsistent with least-cost planning best practices. Whether it is the

IRP, or in the practice of evaluating purchased power opportunities, the costs for all resources—whether conventional self-build or renewable contracts—should be evaluated over the full lifetime of the resource, not within a company-imposed ceiling.[37]

C. The Companies Should Fairly Evaluate Wind Resources.

Wind power has vast potential to provide clean power to North Carolina utility customers with little to no fuel or regulatory price risk, while driving significant economic development. North Carolina's electric suppliers should seriously consider the potential of wind resources, which would provide fuel-free, carbon-free, indigenous energy to their customers.

As discussed in a previous section, the Companies' assumption of unreasonably high costs and escalation rate for on-shore wind resources has biased their IRP modeling against these resources. Meanwhile, potential on-shore coastal wind projects continue to languish. For example, the 300 MW Desert Wind project proposed by Iberdrola subsidiary Atlantic Wind, LLC for rural Perquimans and Pasquotank counties would bring $787 million in private investment to the State and would generate an estimated 750,000-950,000 RECs annually.[38] Atlantic Wind received a Certificate of Public Convenience and Necessity for the project from the Commission in 2011.[39] Nearly four years later, with environmental permitting and other siting approvals substantially

[37] DEP may prefer to establish contract terms that are shorter than the useful lifetime of the resource. However, contract terms that cover only a portion of the resource lifetime necessarily require a premium price. This premium price cannot be fairly compared against the optimally low cost of another resource which is evaluated over its full lifetime.
[38] Motion to Renew Certificate of Public Convenience and Necessity to Construct a Merchant Plant, Docket No. EMP-49, Sub 0 (Mar. 21, 2013).
[39] Order Granting Certificate and Accepting Registration of New Renewable Energy Facility, Docket No. EMP-49, Sub 0 (May 3, 2011).

complete, the project appears to be "on ice," and the developer has not yet executed a PPA with an electric utility.[40]

Further, the long-term potential for offshore wind warrants research and development. DEC and DEP should engage with other Carolinas and 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, as a key near-term step in opening up the potential of this renewable resource. Based on the 2014 IRPs, the Companies do not appear to be exploring the possibility of a demonstration project.

VI. CONCLUSION

In light of the foregoing, the DEC and DEP 2014 IRPs resulted in the selection of preferred resource portfolios that, if implemented by the Companies, would be unnecessarily costly, risky, and polluting. To correct these flaws and minimize costs and risks to ratepayers and the environment, the Commission should issue an order directing the Companies to implement the following improvements, which are set forth in greater detail in the previous sections:

- Evaluate the costs to ratepayers of various resources over both the short- and long term, to accurately assess their risks and benefits;
- Clearly disclose the results of any analyses of changes to coal unit operations necessary to comply with forthcoming air, water and waste regulations;

[40] Atlantic Wind's Annual Progress Report, Docket No. EMP-49, Sub 0 (Dec. 22, 2014); "How new turbine technology will open up the Southeast to wind development," Utility Dive, (Jan. 15, 2015), available at http://www.utilitydive.com/news/how-new-turbine-technology-will-open-up-the-southeast-to-wind-development/347333/.

- Plan to achieve the energy efficiency savings targets agreed to in connection with the Duke Energy-Progress Energy merger, and evaluate energy efficiency as a resource that competes on its own merits with supply-side resources and can grow over the planning horizon;

- 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; and

- Study best practices for modeling utility-scale and distributed solar technologies and integrating such analysis into resource plans, and incorporate those practices into development of future IRPs.

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Implementing these improvements 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 IRPs.

Respectfully submitted this 2nd day of March, 2015.

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CERTIFICATE OF SERVICE

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

This 2nd day of March, 2015.

s/ Robin G. Dunn