OFFICIAL COPY

NC SUSTAINABLE
ENERGY ASSOCIATION

16 May 2014

FILED
MAY 16 2014
Clerk's Office
N.C. Utilities Commission

To: Chief Clerk
The North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

From: The North Carolina Sustainable Energy Association
P.O. Box 6465
Raleigh, NC 27628

Re: NCSEA's Corrected IRP Comments
(Commission Docket No. E-100, Sub 137)

Honorable Clerk and Commissioners:

I serve as counsel and policy director for the North Carolina Sustainable Energy Association ("NCSEA"). The attached *Corrected Comments* are being filed to correct an analytical error in the *Comments* filed by NCSEA in this docket on 11 April 2014. NCSEA's Workpaper No. 2 in Exhibit A to NCSEA's 11 April 2014 *Comments* presented solar nameplate capacity data from DEC's and DEP's integrated resource plans as if the data provided in the plans were additive rather than cumulative. Thus, for example, the original Workpaper No. 2 indicated that, in its 2013 plan, DEC expects 15,421 MWs of installed solar by 2028; the revised Workpaper No. 2 corrects this error to reflect that, in its 2013 plan, DEC expects 1,689 MWs of installed solar by 2028.

In addition to containing a revised NCSEA Workpaper No. 2, the attached *Corrected Comments* contain derivative alterations (1) to the text on pages 10 and 11 of the comments and (2) to Figure 5. The referenced text and the figure were based on the original Workpaper No. 2. As such, the correction to the workpaper also necessitates the corrections to the text and the figure.

The corrections being made in the *Corrected Comments* do not in any way alter or change NCSEA's arguments or recommendations made in its original *Comments*.

To save paper, Exhibits B, C, and D to NCSEA's 11 April 2014 Comments are not being refiled as there were no alterations to any of these exhibits and the original exhibits remain accessible via the Commission's website.

Sincerely,

Michael D. Youth
Counsel & Policy Director

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

In the Matter of:	)	CORRECTED
2013 Biennial Integrated Resource Plans	)	COMMENTS
and Related 2013 REPS Compliance	)	
Plans	)	

FILED
MAY 16 2014
Clerk's Office
N.C. Utilities Commission

NCSEA'S COMMENTS

Pursuant to the North Carolina Utilities_ Commission ("Commission") *Order Establishing Dates for Comments on Integrated Resource Plans and REPS Reports* issued in this docket on 11 October 2013, as modified by the 13 March 2014 Commission *Order Granting Further Extensions of Time*, the North Carolina Sustainable Energy Association ("NCSEA") submits the following initial comments on the 2013 integrated resource plans ("IRPs") and 2013 REPS compliance plans of Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, Inc. ("DEP"), and Dominion North Carolina Power ("DNCP").

Introduction

NCSEA's initial comments are arranged as follows: First, NCSEA provides general contextualizing comments about DEC's and DEP's existing generation resources and their 2013 plans to bring additional generation resources online during the planning horizon (*i.e.*, through 2028). Second, NCSEA more narrowly discusses DEC's and DEP's plans as they relate to renewable energy generation resources and demand-side management/energy efficiency ("DSM/EE") resources. Third, building upon these comments, NCSEA makes four IRP-related arguments:

a. To maintain or even enhance the value of the IRP process, the Commission should reaffirm the foundational importance of the proceeding and the need for consistency with other proceedings, including the avoided cost proceeding;

b. To maintain or even enhance the value of the IRP process, the Commission should require the utilities to set out concisely in their IRPs the key policy landscape assumptions upon which their plans are based;

c. The utilities need to be pushed to innovate if they are to exceed their "base case" DSM/EE projections and approximate the performance savings to which they aspire and the Commission can provide the needed "push" by strongly encouraging the utilities to work with stakeholders to develop new programs and measures, including a combined heat and power ("CHP") pilot program; and

d. The utilities need to be pushed to innovate if they are to exceed their "base case" DSM/EE projections and approximate the performance savings to which they aspire and the Commission can provide the needed "push" by strongly encouraging the utilities to advance their data access protocols, including making their forms for customer authorization of sharing usage information with a third-party accessible via the internet.

Next, NCSEA's initial comments turn to the utilities' REPS compliance plans, with a quick review of past and projected compliance costs relative to the statute-based cost cap. Finally, NCSEA makes two REPS compliance plan-related arguments:

e. DEP, DEC and DNCP should be directed to submit letters containing a one-sentence certification that their 2009 REPS compliance plan reviews have been conducted and to include, in future REPS compliance plans, a one-sentence certification that a review has been conducted (if this is not otherwise obvious via the filing of a revised past compliance plan with removed redactions); and

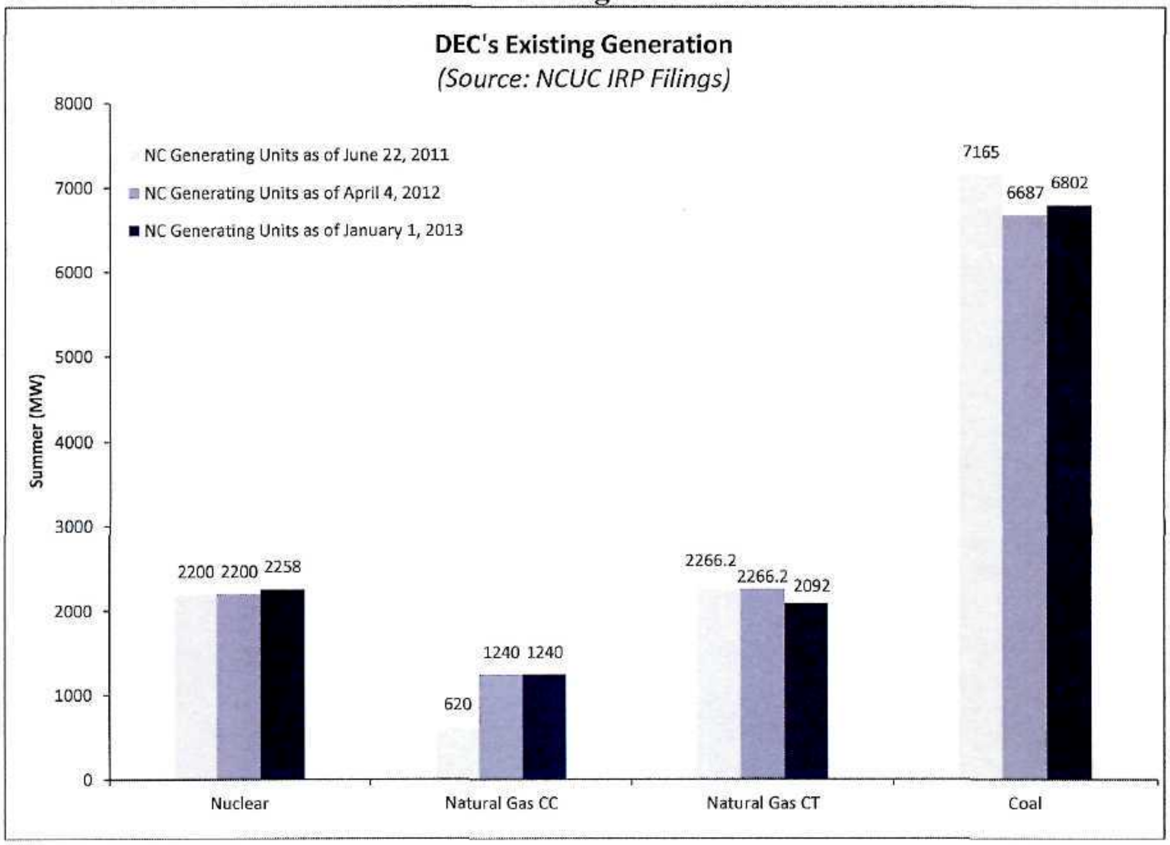
f. In light of the ongoing first phase of the 2014 biennial avoided cost proceeding, the utilities should be directed to create their 2014 REPS compliance plan avoided cost projections using the methodological approaches approved in the 2012 biennial avoided cost order, together with a statement (for DEC and DEP) indicating whether the effect of the Joint Dispatch Agreement was incorporated or not.

Attached to NCSEA's initial comments are four exhibits: **Exhibit A** includes NCSEA's workpapers, showing the quantitative data and sources therefor used to generate graphs and other numbers cited herein; **Exhibit B** is a DEC/DEP data response to a Southern Alliance for Clean Energy data request; **Exhibit C** is an Opower report; and **Exhibit D** contains DEC/DEP and DNCP data responses related to usage information authorization forms.

Existing Generation Resources and Planned Generation Resources

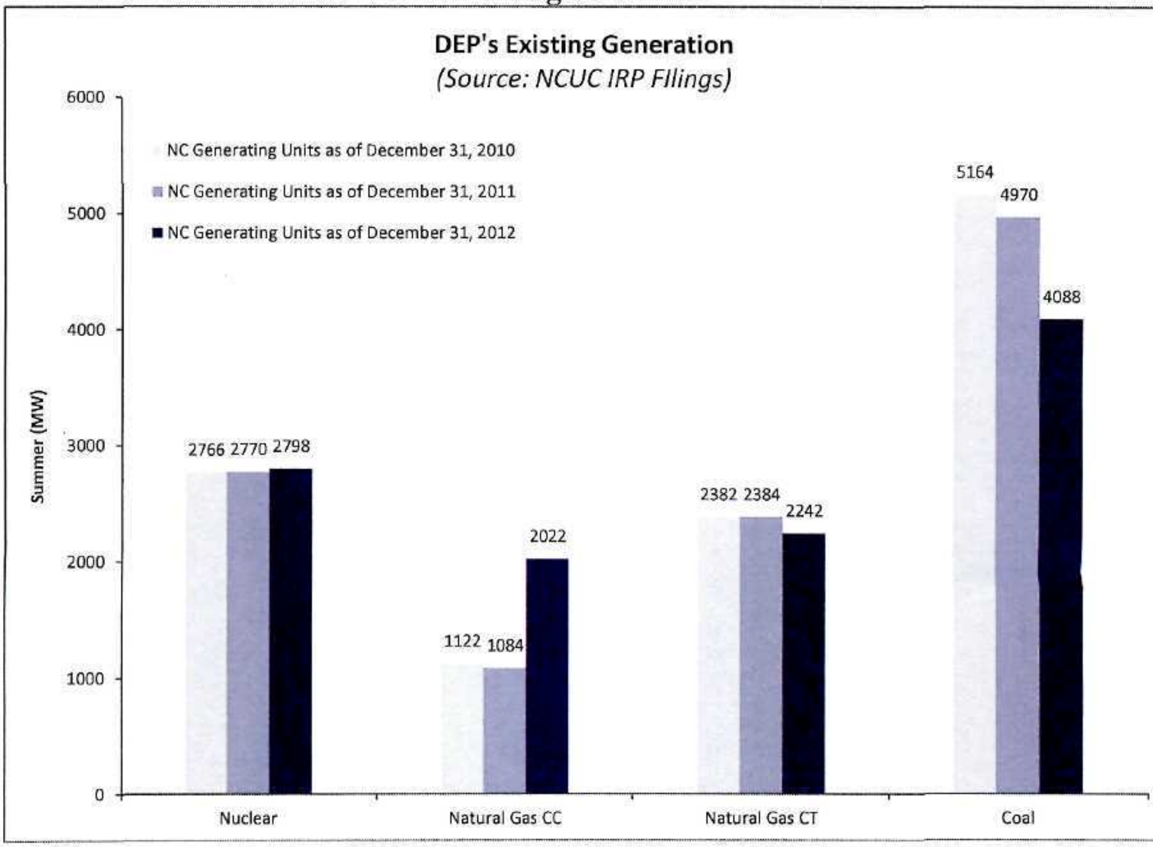
Year to year, the utilities' existing generation resources can and do change. When such changes occur, it is important to keep these changes in mind as they influence the utilities' constantly evolving resource plans. Together, DEC's and DEP's existing generation includes: 5,056 MW of nuclear; 3,262 MW of natural gas combined cycle (CC); 4,334 MW of natural gas combustion turbine (CT); and 10,890 MW of coal. *See* Figures 1 and 2 *infra.* Coal remains the dominant generation resource.

Figure 1[1]



[1] *Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan ("DEC 2011 IRP")*, Table 5.A, pp. 38, 40, 47, Commission Docket No. E-100, Sub 128 (1 September 2011); *Duke Energy Carolinas, LLC's 2012 Integrated Resource Plan ("DEC 2012 IRP")*, Table 5.A, pp. 44-46, 53, Commission Docket No. E-100, Sub 137 (4 September 2012); *Duke Energy Carolinas, LLC's 2013 Integrated Resource Plan ("DEC 2013 IRP")*, pp. 52-54, 58, Commission Docket No. E-100, Sub 137 (15 October 2013).

Figure 2[2]



As the figures illustrate, DEC's and DEP's combined traditional generation *capacity* has not changed significantly over the past three years. From 2011 to 2013, DEC's existing summer capacity (MW) increased 1.15%; during the same period, DEP's existing summer capacity (MW) decreased 2.5%. While overall traditional generation capacity has not changed significantly during the past three years, there has been a marked resource shift as almost 1,600 MWs of CC has come on line and an almost-equal amount of coal capacity has been retired. *See* Figures 1 and 2 *supra.*

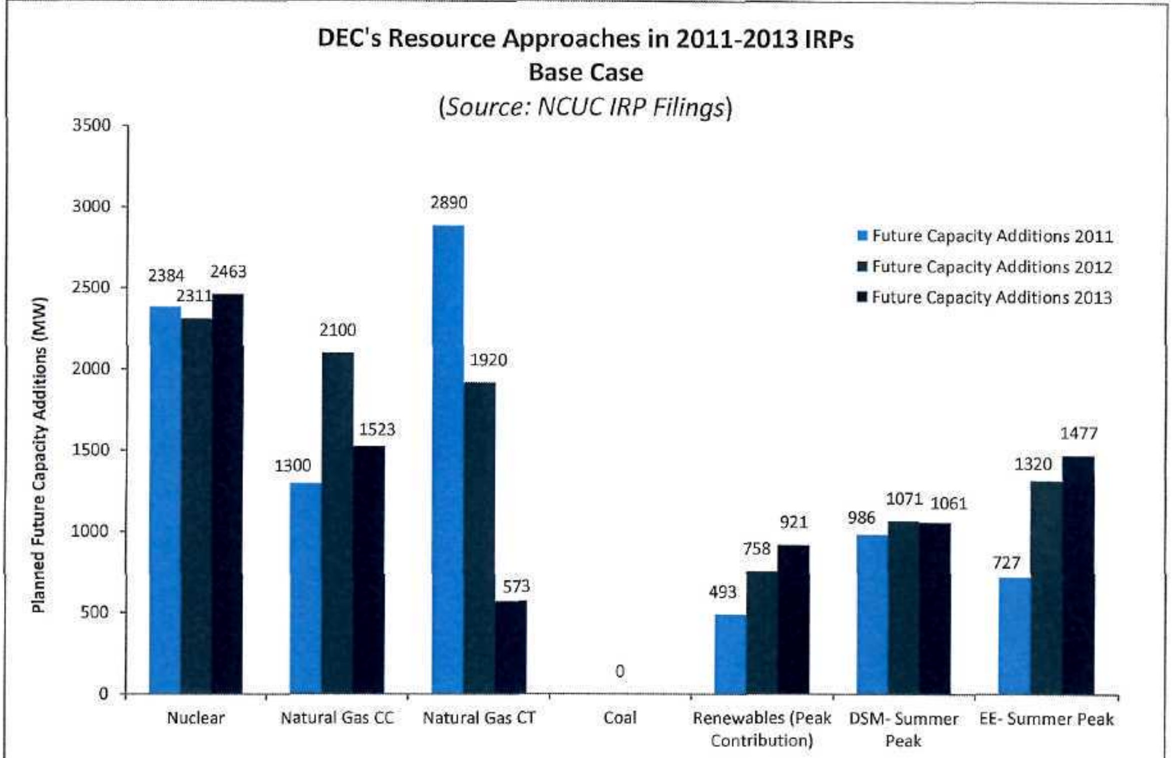
---

[2] *Progress Energy, Inc.'s 2011 Integrated Resource Plan ("DEP 2011 IRP")*, Appendix B, Commission Docket No. E-100, Sub 128 (1 September 2011); *Progress Energy, Inc.'s 2012 Integrated Resource Plan ("DEP 2012 IRP")*, Appendix B, Commission Docket No. E-100, Sub 137 (4 September 2012); *Duke Energy Progress 2013 Integrated Resource Plan ("DEP 2013 IRP")*, pp. 48-51, Commission Docket No. E-100, Sub 137 (15 October 2013).

Against the backdrop of DEC's and DEP's existing generation resources, the implications of their "base case" resource plans[3] over the last three years are better understood. Neither utility's plans over the last three years have included an addition of coal capacity; both utilities' plans have, however, included additions of significant amounts of CC capacity over the planning horizon: 2,500 MWs in the 2011 plans, 5,200 MWs in the 2012 plans, and, most recently, 4,800 MWs in the 2013 plans. *See* Figures 3 and 4 *infra*. As far as traditional generation resources go, a clear shift is underway – from the existing reliance on coal capacity to an increased future reliance on CC capacity.

[3] The "base case" resource plans represent updates to the utilities' 2012 IRPs but do "not take into account the [potential] sharing of capacity between DEC and DEP. However, the Base Case incorporates the JDA between DEC and DEP which represents a non-firm energy only commitment between the companies." *DEC 2013 IRP*, p. 27, Commission Docket No. E-100, Sub 137 (15 October 2013).

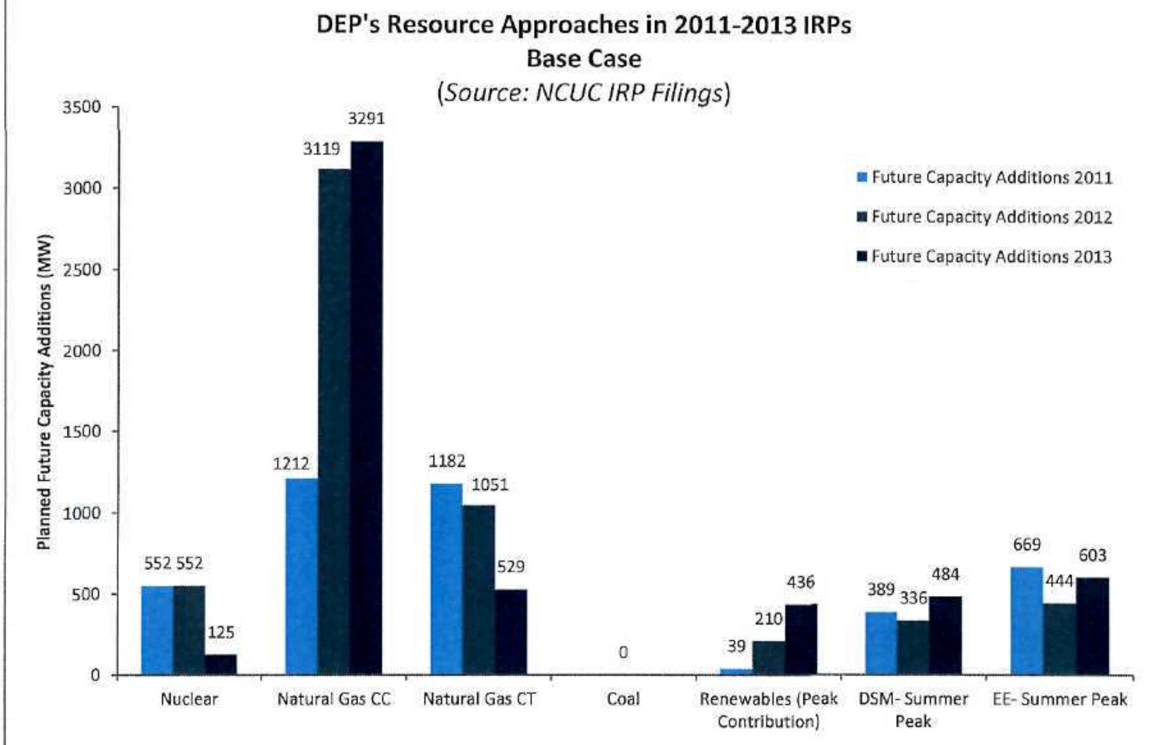
Figure 3[4]



DEC's future capacity additions in 2013 include 170 MW attributed to the Lee 3 NG Conversion.
Under DEC's and DEP's "joint planning scenario", 680 MW of CC in 2017 is delayed one year, 843 MW of CC in 2019 is reduced and delayed two years, 403 MW of CT is delayed one year, and 403 MW of CT is delayed outside of the study period.

[4] **Exhibit A** (NCSEA Workpaper 1).

Figure 4[5]



Under DEC's and DEP's "joint planning scenario", 680 MW of CC in 2017 is delayed one year, 843 MW of CC in 2019 is reduced and delayed two years, 403 MW of CT is delayed one year, and 403 MW of CT is delayed outside of the study period.

Almost all of the utilities' planned CC capacity is scheduled to come on line in the next five to seven years – *i.e.*, in the first half of the 15-year planning horizon. *See* DEC's and DEP's "base case" tables *infra.*

[5] **Exhibit A** (NCSEA Workpaper 1).

Table 1-A DEC Base Case (Source: *DEC 2013 IRP*, p. 8, Commission Docket No. E-100, Sub 137 (15 October 2013))				
Year	Resource		MW	
2014	Nuclear Uprates		20	
2015	Lee 3 NG Conversion	Nuclear Uprates	170	32
2016				
2017	New CC	Nuclear Uprates	680	45
2018	VC Summer Nuclear		66	
2019	New CC		843	
2020	VC Summer Nuclear		66	
2021				
2022	New CT		403	
2023				
2024	New Nuclear		1117	
2025				
2026	New Nuclear		1117	
2027				
2028				
Note: Table includes both designated and undesignated capacity additions				

Table 1-A DEP Base Case (Source: *DEP 2013 IRP*, p. 8, Commission Docket No. E-100, Sub 137 (15 October 2013))					
Year	Resource			MW		
2014	Sutton CC*		Nuclear Uprates*	625		9
2015	Nuclear Uprates			24		
2016						
2017						
2018	Fast Start CT	CC Uprates	VC Summer Nuclear	126	137	46
2019	New CC			843		
2020	VC Summer Nuclear			46		
2021	New CC			843		
2022	New CC			843		
2023						
2024						
2025						
2026						
2027	New CT			403		
2028						
Note: Table includes both designated and undesignated capacity additions *Sutton CC and nuclear uprates projected online 2013; Sutton Coal units 1-3 to be retired Dec 2013						

The Plans for Renewable Energy Resources

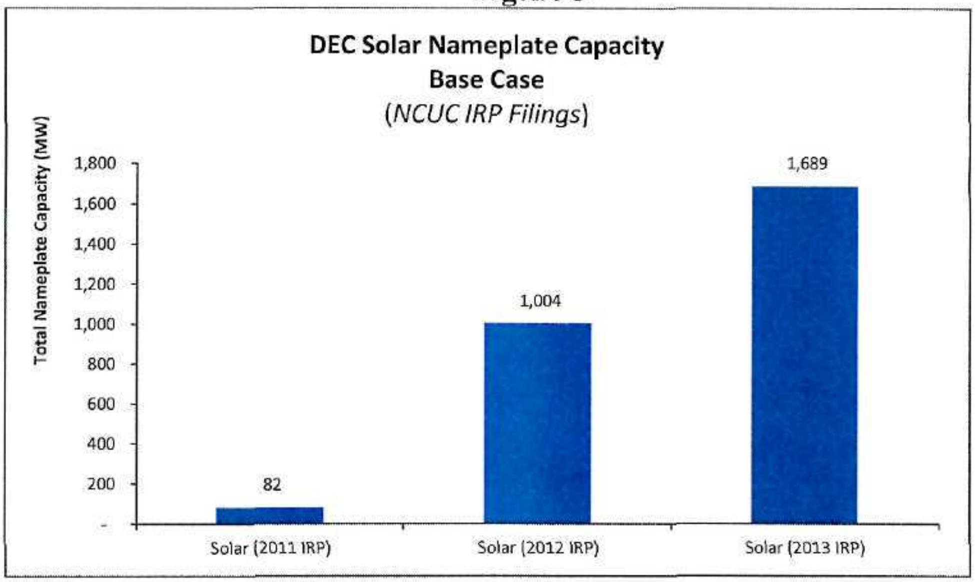
If nothing else were to change in the utilities' base case IRPs, their near-term shift to increased reliance on natural gas would be akin to putting all of our planning "eggs in one basket"[6] even as the Commission has "recognize[d] that diversity in a utility's resource mix may help to protect the utility and its customers from fuel price fluctuations, fuel unavailability, and regulatory uncertainties, and may also ensure stability and reliability in the State's electricity supply." *Order Approving Integrated Resource Plans and REPS Compliance Plans*, p. 40, Commission Docket No. E-100, Sub 137 (14 October 2013). <u>However, something else *is* changing in the utilities' plans.</u> The utilities' 2013 IRPs reflect an increasing willingness to diversify into clean energy resources, particularly renewable energy. *See* Figures 3 and 4 *supra*. DEC's and DEP's planned renewables-based *peak* capacity increased to 1,357 MW in their 2013 IRPs – a 155% increase from a combined 532 MW in their 2011 IRPs and a 40% increase from a combined 968 MW in their 2012 IRPs. *Id.*

At the same time that DEC and DEP increased their planned renewables-based *peak* capacity additions, the two utilities also revised upward their planned renewables-based *nameplate* capacity additions. The increase in planned renewables-based nameplate capacity is overwhelmingly attributable to solar. By way of example, as illustrated in Figure 5 *infra*, DEC's planned solar nameplate capacity jumped by more than 1000% between 2011 and 2012 and increased an additional 68% from 1,004 MW in

[6] Duke Vice President Rob Caldwell has said, "I think you're going to see us asking regulators, 'Here's our least-cost plan – today you know that's going to be a gas plant – but we think there's an opportunity for a more diversified portfolio so we don't get all our eggs in one basket.'" Downey, J., *Duke Energy mulls adding solar to the utilities' mix*, Charlotte Business Journal (8 November 2013) (accessed on 5 April 2014 at http://www.bizjournals.com/charlotte/print-edition/2013/11/08/duke-mulls-adding-solar-to-utilities.html?page=all). Like traditional physical and financial hedges, diversifying into clean energy resources, including solar, wind, hydro, biomass and DSM/EE, offers an additional technique for hedging against the historic (and recent "polar vortex"-related) volatility of natural gas prices.

the 2012 plan to 1,689 MW in the 2013 plan. DEP's 2013 IRP adds 485 MW of planned solar nameplate capacity for a DEC-DEP planned total of 2,174 MWs of solar nameplate capacity operational by the end of the 2013 IRP planning horizon. *See* **Exhibit A** (Revised NCSEA Workpaper 2).

Figure 5[7]



The utilities' plans for greater inclusion of renewables, including solar, is not only contributing diversity to the utilities' portfolios, but it is also actually helping to alleviate the utilities' need to rely so heavily on natural gas: "[DEC]'s plan currently projects that by the end of the planning horizon, [DEC] will have met over 700 MW of peak demand through solar resources – the equivalent of one large natural gas facility." *DEC 2013 IRP*, p. 5, Commission Docket No. E-100, Sub 137 (15 October 2013).

As stated above, the utilities' 2013 IRPs reflect an increasing willingness to diversify into renewable energy resources. NCSEA finds this promising. At the same time, NCSEA is concerned that these promising plans for renewable energy resources could be viewed as interesting conceptual exercises, the product of which is limited to

[7] **Exhibit A** (Revised NCSEA Workpaper 2).

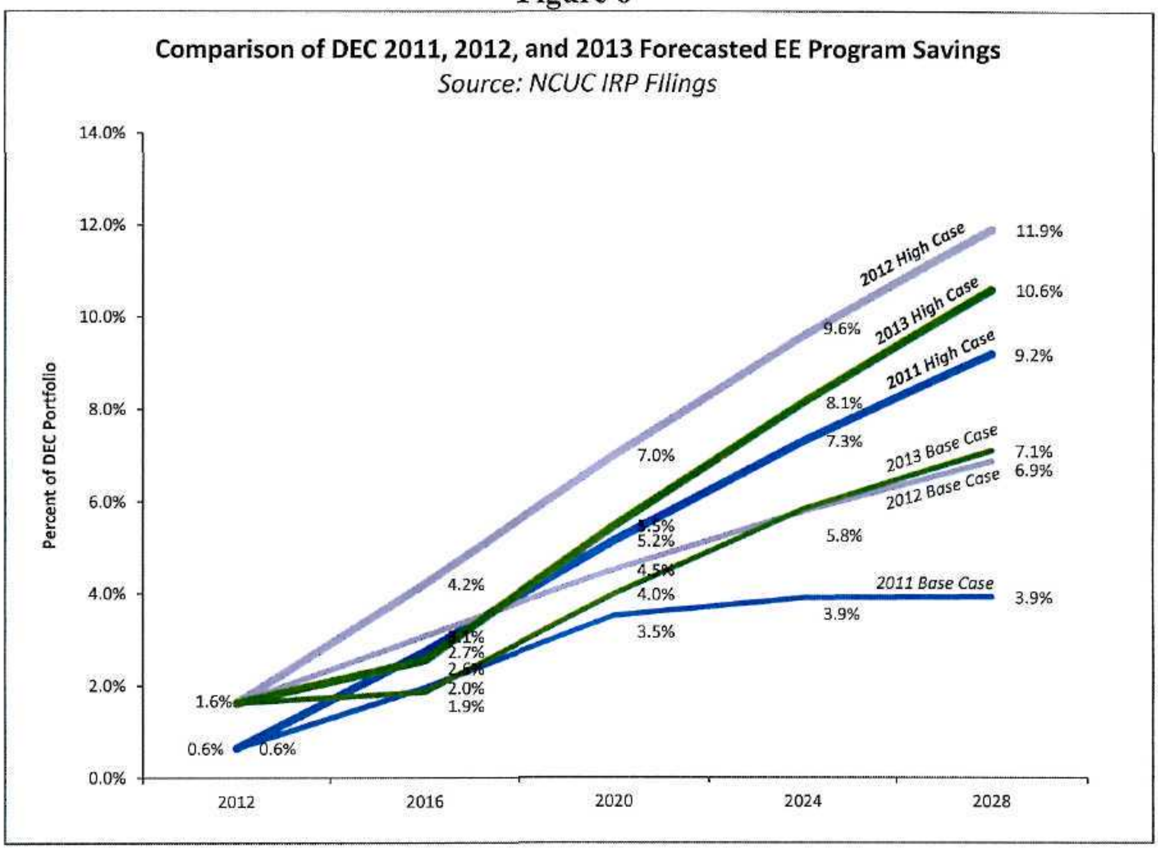
life within the vacuum of this proceeding. The IRP proceeding draws attention from an array of stakeholders; the parties, including the utilities and the Public Staff, dedicate time, talent, and treasure to the IRP process. The value of the IRP process is significantly diminished if the proceeding is treated as a stand-alone proceeding and not as a proceeding that is a foundational building block for "upper story" proceedings like the biennial avoided cost proceeding. To maintain or even enhance the value of the process, NCSEA argues, *infra*, that (a) the Commission should reaffirm the foundational importance of the IRP process and the need for consistency across multiple proceedings, including the avoided cost proceeding, and (b) the Commission should require the utilities to set out concisely in their IRPs the key policy landscape assumptions upon which their plans are based.

<u>The Plans for DSM/EE Resources</u>

The utilities' 2013 IRPs reflect a much more pronounced willingness to diversify into renewable energy resources than into DSM/EE. DEC's and DEP's 2013 IRPs project DSM/EE *peak* capacity increases totaling a combined 3,625 MWs – reflecting a 31% increase from a combined 2,771 MWs in the 2011 IRPs and a 14% increase from a combined 3,171 MWs in the 2012 IRPs. *See* Figures 3 and 4 *supra*. While the utilities' 2013 "base case" projections reflect DSM/EE increases by the end of the planning horizon, a comparison to last year's IRPs reveals that a temporal shift has occurred with DEC and DEP now projecting, in their "base cases," less DSM/EE contribution to peak capacity in the near-term – *i.e.*, over the next two to eight years. In other words, the utilities' plan-over-plan "base case" *peak* capacity increases are back-end loaded, coming to fruition only in the later years of the planning period. *See* Figures 6 and 7 *infra*.

In addition to "base case" projections, Figures 6 and 7 include DEC's and DEP's "high case"/"environmental focus" projections. The "high case" projections reflect DEC's/DEP's "aspirational energy efficiency targets . . . approximately twice the level considered in the 'base case' resource plan." *DEC 2013 IRP*, p. 33, Commission Docket E-100, Sub 137 (15 October 2013); *DEP 2013 IRP*, p. 32, Commission Docket E-100, Sub 137 (15 October 2013).

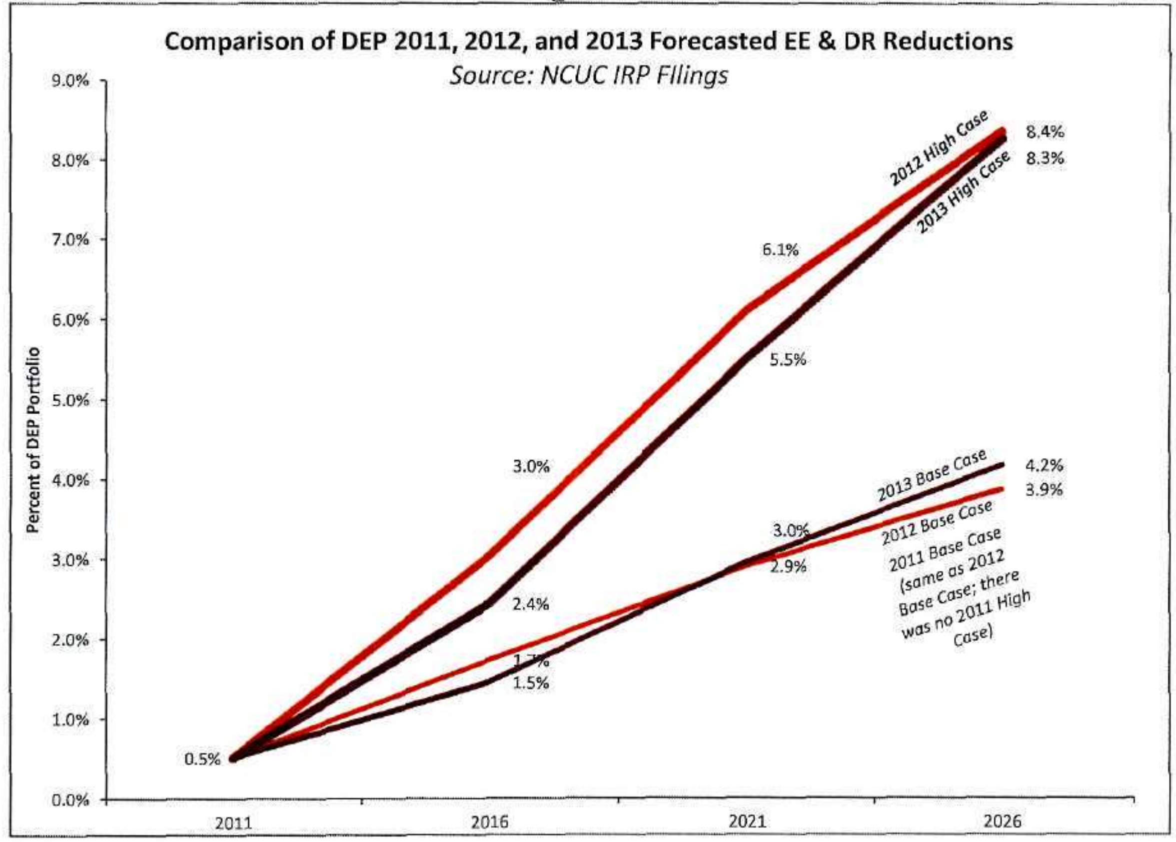
Figure 6[8]



---

[8] **Exhibit A** (NCSEA Workpaper 3).

Figure 7[9]



As the Commission will recall, DEC and DEP have "agreed to adopt the following EE savings performance targets for five years: an annual savings target of 1% of the previous year's retail electricity sales beginning in 2015 and a cumulative savings target of 7% of retail electricity sales over the five-year period of 2014-2018." *Direct Testimony of Timothy J. Duff for DEC*, p. 21, Commission Docket No. E-7, Sub 1032 (6 March 2013); *see Supplemental Comments of Environmental Intervenors*, Exhibit A, Commission Docket Nos. E-2, Sub 998 & E-7, Sub 986 (18 June 2012) (copy of 8 December 2011 settlement agreement). The savings projected in the "high case"

---

[9] **Exhibit A** (NCSEA Workpaper 4).

scenarios set out in Figures 6 and 7, *supra*, are more consistent with the savings performance targets set out in the 8 December 2011 settlement agreement.

DEC and DEP will have to be innovative to meet their obligations to aspire.[10] As stated in DEC's/DEP's 2013 IRPs,

> [t]he high EE savings projections are well beyond the level of savings attained by DEC[/DEP] in the past and higher than the forecasted savings contained in the new market potential study. The effort to meet them will require a substantial expansion of DEC's[/DEP's] current Commission-approved EE portfolio. *New programs and measures must be developed, approved by regulators, and implemented within the next few years.* More importantly, significantly higher levels of customer participation must be generated.

DEC 2013 IRP, p. 91, Commission Docket No. E-100, Sub 137 (15 October 2013) (emphasis added); *DEP 2013 IRP,* p. 81, Commission Docket No E-100, Sub 137 (15 October 2013) (emphasis added).

Again, the utilities' 2013 IRPs reflect an increasing willingness to diversify into clean energy resources, including DSM/EE. NCSEA finds this promising. At the same time, the utilities need to be pushed to innovate if they are to exceed their "base case" DSM/EE projections and approximate the performance savings to which they aspire. NCSEA argues, *infra*, that the Commission can provide the needed "push" by (a) strongly encouraging the utilities to work with stakeholders to develop new programs and measures, like a CHP pilot program, and (b) strongly encouraging the utilities to advance their data access protocols such that customers' authorized proxies can access data and use it in the development and refinement of tools that could serve as cornerstones for future DSM/EE programs and measures.

---

[10] Merriam-Webster defines the verb "aspire" as "to seek to attain or accomplish a particular goal."

IRP-Related Arguments

To maintain or even enhance the value of the IRP process, NCSEA believes that (a) the Commission should reaffirm the foundational importance of the IRP process and the need for consistency across multiple proceedings, including the avoided cost proceeding, and (b) the Commission should require the utilities to set out concisely in their IRPs the key policy landscape assumptions upon which their plans are based.

Furthermore, while the utilities' 2013 IRPs reflect an increasing willingness to diversify into clean energy resources, including DSM/EE, the utilities need to be pushed to innovate if they are to exceed their "base case" DSM/EE projections and approximate the performance savings to which they aspire under the 8 December 2011 settlement agreement. The Commission can provide the needed "push" by (c) strongly encouraging the utilities to work with stakeholders to develop new programs and measures, like a CHP pilot program, and (d) strongly encouraging the utilities to advance their data access protocols such that customers' authorized proxies can access data and use it in the development and refinement of tools that could serve as cornerstones for future DSM/EE programs and measures.

a. Consistency Across Multiple Proceedings

The value of the IRP process is significantly diminished if the proceeding is treated as a stand-alone proceeding and not as a proceeding that is a foundational building block for "upper story" proceedings, like the biennial avoided cost proceeding. The Commission should endorse consistency across proceedings. NCSEA's argument will focus, for illustrative purpose, on the relationship of the IRP to the biennial avoided cost proceeding.

In each IRP, the utilities make assumptions and project such things as CT costs and capacity needs. The same kind of assumptions and projections are needed to calculate avoided cost rates. When the assumptions and projections in these two proceedings are inconsistent, it raises multiple questions which require undue amounts of time to uncover and understand. Inconsistency can call into question the accuracy of one or the other proceeding. It was for this very reason that, in the 2012 biennial avoided cost proceeding, NCSEA and "the Public Staff emphasized the importance of consistency between the assumptions and the projected CT costs used in the utilities' respective IRPs and avoided cost calculations." *See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, p. 17, Commission Docket No. E-100, Sub 136 (21 February 2014) (referring to Public Staff's Reply Comments).

Commission endorsement of consistency across proceedings would help reinforce the concept that proceedings required by Chapter 62 of the General Statutes are inter-related and contribute to a holistic approach to electric service in the State. 40 years ago, in *State ex rel. Utilities Com. v. General Tel. Co.*, the North Carolina Supreme Court stated: "Chapter 62 provides for the granting of a monopoly and for the regulation of its service and its charges by the Utilities Commission. *The entire chapter is a single, integrated plan.* Its several provisions must be construed together[.]" 285 N.C. 671, 680, 208 S.E.2d 681, 687 (1974) (emphasis added). Last year, the Supreme Court reaffirmed its earlier conclusion that Chapter 62 is "a single, integrated plan" and that "[i]ts several provisions must be construed together[.]" *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 495, 739 S.E.2d 541, 548 (2013). Implementation of an integrated plan requires reasonable consistency across proceedings.

NCSEA understands that the Commission may not view the biennial avoided cost proceeding as part of Chapter 62's integrated plan. Last year, the Commission concluded that

> biennial avoided costs are established by the Commission pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA), not Chapter 62. The goal underlying PURPA's avoided cost provisions is mainly the development of small wholesale power producers. On the other hand, the "single, integrated plan" of Chapter 62 cited by the Supreme Court in the *General Telephone* and *Cooper* decisions is in reference to the Commission's role in setting retail rates for utilities providing monopoly service, a very different function.

Order Granting General Rate Increase, p. 79, Commission Docket No. E-2, Sub 1023 (30 May 2013). NCSEA believes this Commission conclusion should be re-visited and clarified so that it is not used to justify *inconsistency* between the IRP and avoided cost proceedings. Chapter 62 mandates the IRP process in N.C. Gen. Stat. § 62-110.1(c). Similarly, the determination of avoided cost rates has been incorporated into Chapter 62 such that the process should be considered part of, and not foreign to, Chapter 62. *See, e.g.*, N.C. Gen. Stat. § 62-156 (requiring a proceeding every two years for setting avoided cost rates); N.C. Gen. Stat. § 62-133.8(h)(1)a. (referring to "avoided costs" in connection with electric suppliers' annual REPS cost recovery proceedings).

A Commission endorsement of the need for consistency would be particularly timely given the opening of the 2014 biennial avoided cost proceeding. In late February, the Commission issued an order opening the 2014 avoided cost proceeding, during which the Commission will, among other things, entertain arguments related to how capacity payments are made and whether there should be a cap on capacity payments. *Order Establishing Biennial Proceeding and Scheduling Hearing*, p. 2, Commission Docket No. E-100, Sub 140 (25 February 2014). The utilities' projections of capacity needs in their

2014 IRPs (along with their assumptions and projections of CT costs) should be reasonably consistent with the inputs used to derive their 2014 proposed avoided cost rates.

b. Concise Articulation of Key Policy Assumptions

The IRP process is, at least in part, intended to enable the Commission to inform the State's executive and legislative decision-makers about any "long-range needs for expansion of facilities for the generation of electricity in North Carolina[.]" N.C. Gen. Stat. § 62-110.1(c). To this end, the Commission is required, each year, to "submit to the Governor and to the appropriate committees of the General Assembly a report of its analysis and plan, the progress to date in carrying out such plan, and the program of the Commission for the ensuing year in connection with such plan." *Id.* To the extent our State's decision-makers rely on the report to assist them in gauging, from a policy standpoint, whether they find the utilities' plans to be in the people's best interest, it would be helpful for them to understand the key policy assumptions used by the utilities in proposing their plans.

In their IRPs, the utilities analyze multiple scenarios using various policy assumptions. The utilities ultimately recommend approval of "base case" plans. The "base case" plans, like all the scenarios, are built upon certain policy assumptions. For example, a utility might assume one or all of the following: (a) continuation of the REPS law, (b) discontinuation of the REPS law, (c) enactment of a South Carolina RPS,[11] (d)

[11] "[T]he Company has assumed for purposes of the 2013 IRP that a new legislative requirement would be implemented in the future that would result in additional renewable resource development in South Carolina. For planning purposes, DEC has assumed that the requirement would be similar in many respects to the NC REPS requirement, but with a different implementation schedule. Specifically, the Company has assumed that this requirement would have an initial 3% milestone in 2018 and would gradually increase to

continuation/extension of the North Carolina renewable energy tax credit, (e) discontinuation of the North Carolina renewable energy tax credit, and (f) legalization of third-party sales in North Carolina.[12] There are certainly other assumptions that could be made as well. Given the multiple scenarios that are analyzed in the utilities' IRPs, the piecemeal articulation of assumptions in various places throughout a utility's plan can cause confusion about which scenarios rely upon which assumptions. Similarly, some key assumptions (*e.g.*, the third-party sales assumption) may not be articulated at all in the plans.

To avoid confusion and provide our State decision-makers with as clear a report as possible, each utility should be required to concisely list in one place in its filed plan all of the key policy assumptions which underlie its "base case" or recommended plan. To the extent the utilities assume a *status quo* policy landscape – *i.e.*, that all federal and state laws, regulations and rules will remain as is, including any changes imbedded in those policies like a REPS compliance step-up or the sunset of a tax credit – the utilities can simply state this. However, to the extent the utilities assume a deviation from the *status quo* policy landscape, they should be required to expressly articulate each such deviation. These articulations can then be incorporated into the Commission's report to the State's decision-makers, where they will help those decision-makers better understand the plans and their policy underpinnings (and whether the decision-makers need to take, or refrain from taking, any actions).

---

a 12.5% level by 2026. Similar to NC REPS, this assumed legislative requirement would incorporate renewable energy and EE, as well as a limited capability to utilize out of state unbundled purchases of RECs." *DEC 2013 IRP*, p. 17, Commission Docket No. E-100, Sub 137 (15 October 2013); *see DEP 2013 IRP*, p. 17, Commission Docket No. E-100, Sub 137 (15 October 2013) (DEP makes same assumption).

[12] DEC and DEP appear to have assumed, in at least one scenario, that third-party sales will be legalized in North Carolina in 2015. *SACE DR*, Item No. 1-16, Page 1 of 1, Commission Docket No. E-100, Sub 137 (attached as Exhibit B hereto).

c. *Encouraging Innovative DSM/EE Programs and Measures*

In a recent paper entitled "Five Universal Truths about Energy Consumers,"[13] Opower found one universal truth to be that "[u]tilities are not meeting customer expectations" (p. 3). Our State Supreme Court has recognized "the customer-driven focus of Chapter 62 as a whole." *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 495, 739 S.E.2d 541, 548 (2013). Our Supreme Court has also recognized that a "complacent monopoly" is not in the public interest. *State ex rel. Utilities Com. v. General Tel. Co.*, 285 N.C. 671, 680, 208 S.E.2d 681, 687 (1974). In order to better meet customer expectations, our electric utilities must innovate internally <u>and</u> enable external innovation that can be incorporated into utility operations in the future. It is the Commission's prerogative, and perhaps its duty, to help push the utilities to innovate so as to better serve the public interest.

While the utilities' 2013 IRPs reflect an increasing willingness to diversify into clean energy resources, including DSM/EE, DEC and DEP need to be pushed to innovate if they are to exceed their "base case" DSM/EE projections and approximate the performance savings to which they aspire under the 8 December 2011 settlement agreement.

> The effort to meet the[savings targets] will require a substantial expansion of DEC's[/DEP's] current Commission-approved EE portfolio. *New programs and measures must be developed, approved by regulators, and implemented within the next few years.* More importantly, significantly higher levels of customer participation must be generated.

---

[13] Attached as **Exhibit C** hereto.

DEC 2013 IRP, p. 91, Commission Docket No. E-100, Sub 137 (15 October 2013) (emphasis added); *DEP 2013 IRP,* p. 81, Commission Docket No E-100, Sub 137 (15 October 2013) (emphasis added).

If the utilities are to exceed their "base cases," new DSM/EE programs and measures are needed and they must be customer-driven to secure customer participation. The Commission should strongly encourage the utilities to continue, generally, to seek out – via surveys and other mechanisms – the DSM/EE expectations and desires of electric customers. The Commission should also strongly encourage the utilities to continue to work with customers and stakeholders, such as the U.S. Department of Energy's Southeast Clean Energy Application Center ("SE-CEAC"), to develop and secure near-term approval of a robust combined heat and power ("CHP") pilot program.

NCSEA understands that innovation – *i.e.*, development and approval of new programs and measures – can have an impact on customer bills. NCSEA also understands, however, that when customers get good value from their utility and trust its intentions, they are more likely to be satisfied with the rates they pay. In "Five Universal Truths about Energy Consumers," Opower reported that its

> research uncovered a surprising fact: actual energy costs are not predictive of customer satisfaction with those costs. This is a counter-intuitive finding: one would expect that customers in countries facing high retail electricity costs would be more dissatisfied with cost than customers in countries with low costs. But in fact, our analysis shows no clear relationship between cost and customer perception of cost. We see that even in countries exhibiting quite low electricity costs (by international standards), customers are prone to voice high levels of dissatisfaction regarding cost.
>
> The weak relationship between cost and satisfaction with cost is surprising, and leads to an interesting corollary: factors other than actual [dollars and cents] strongly influence customers' perception of cost. *What it really comes down to is, whether customers feel they are getting good*

> *value from their utility and trust its intentions; if so, then they are more likely to be satisfied with the prices they pay.*

(p. 5) (emphasis added). In short, the potential for near-term rate increases is not a reason to forego or avoid development of innovative DSM/EE programs and measures that can yield mid- and long-term savings when compared to a complacent *status quo* approach.

d. Moving Data Access Forward

In their 2013 IRPs, DEC and DEP state that each

> company continues to expand its portfolio of energy efficiency products and services – offering customers more ways to take control of their energy usage and save money.

DEC 2013 IRP, p. 4, Commission Docket No. E-100, Sub 137 (15 October 2013); *DEP 2013 IRP*, p. 4, Commission Docket No. E-100, Sub 137 (15 October 2013).

Energy savings within the utilities' portfolios of DSM/EE products are only a part of the planning picture; energy savings are also being realized outside the utilities' portfolios. A number of the innovative third-party DSM/EE products that enable the outside savings will mature to the point that they can be considered by the utilities for inclusion in their portfolios. These products, and the innovation pipeline they promise, are created and incubated outside of the utilities. Solar in North Carolina has helped show that enabled third-parties can bring an innovative technology to the point that utilities can buy-in to a mature concept rather than drive the innovation themselves. In the DSM/EE context, if DEC and DEP want to exceed their base case projections (and aim for achievement of the savings they agreed to in the merger settlement), they need to step out of "complacent monopoly" mode and grow more comfortable with enabling outside incubation of innovative products.

One way in which the utilities can enable third-party development of innovative DSM/EE products is by making it easier for utility customers to share their usage data with these third-parties. On this topic, the Commission last year stated as follows:

> [T]he Commission notes that the authorization forms attached to the DEC/DEP [Code of Conduct] include the statement: "DEC/PEC will provide this [customer] data on a non-discriminatory basis to any other person or entity upon the Customer's authorization." Similarly, DNCP states in its reply comments that customers can give written consent to have their data released to a third party. Thus, *it does not appear that the IOUs' customers face an impediment to sharing their usage information with any person they desire, although the IOUs may be able to more readily facilitate the authorization for such sharing by creating a standard authorization form.*

Order Requesting Additional Information and Declining to Initiate Rulemaking, pp. 9-10, Commission Docket No. E-100, Sub 137 (23 August 2013) (emphasis added). While impediments were not apparent to the Commission, it does not mean impediments do not exist. They do.

The Commission followed the quoted statement up by requesting additional information. Specifically, the Commission directed the following two requests to the utilities in Attachment A to its order:

> 4. State the details of the modes by which retail customers can authorize the release of their usage information to a third party . . . [.]
> 5. Does your company have a standard form that retail customers can sign to authorize the release of their usage information to a third party? If so, please attach a copy of the form to your responses.

Id. at Attachment A. The utilities provided the following responses:

	DEC/DEP Response	DNCP Response
State the details of the modes by which retail customers can authorize the release of their usage information to a third party . . . [.]	"Customers must provide explicit and informed written consent prior to DEC or DEP disclosing "Customer Information" (as defined in the Code of Conduct), to a third party. The written consent may be submitted to Duke Energy via email, postal service, fax or other means." *Verified Response to August 23, 2013 Order*, p. 2, Commission Docket No. E-100, Sub 137 (23 September 2013).	"Customers may use the following modes to authorize release of their usage information to a third party: 1) The customer may mail a written release to the Company authorizing release of their usage information to a third party." *Response to August 23, 2013 Order*, p. 4, Commission Docket No. E-100, Sub 137 (23 September 2013).
Does your company have a standard form that retail customers can sign to authorize the release of their usage information to a third party? If so, please attach a copy of the form to your responses.	"DEC and DEP use standard templates for customer consent (attached)." *Verified Response to August 23, 2013 Order*, p. 2, Commission Docket No. E-100, Sub 137 (23 September 2013) (included in **Exhibit D** attached hereto).	"Yes. See Attachment Question 5 for a letter template and a copy of the form." *Response to August 23, 2013 Order*, p. 4, Commission Docket No. E-100, Sub 137 (23 September 2013).

In preparation for the filing of these comments, NCSEA served data requests on the utilities seeking updates and clarification. Specifically, NCSEA asked the utilities (1) to provide the latest versions of the authorization forms the utilities filed in September 2013; (2) to explain how a customer could secure a copy of the form; (3) whether the form is available online; and (4) whether a customer can complete and submit the form online. The utility responses, included in **Exhibit D** attached hereto, indicate: DEC and DEP have revised their forms since September 2013.[14] DEC's and DEP's forms are not available online; instead, as their data responses indicate: "Access [to the DEC/DEP form] is obtained through interaction with [a] DEC[/DEP] customer service

[14] It is also worth noting that DEC's and DEP's form indicates that it is valid for disclosure of information "only once." DNCP's form on the other hand more reasonably covers "requests . . . each time requested within the . . . [authorization] period." The Commission should encourage DEC and DEP to adopt DNCP's more reasonable approach. The DEC and DEP forms also describe a fee to be paid by a third party requesting customer information. Interestingly, the charge is not applicable to requests made in Duke's Ohio, Kentucky or Florida territories. NCSEA believes the fee issue is more appropriately raised in the upcoming smart grid planning process under Commission Rule R8-60.1 and plans to pursue clarification of the fee issue in that proceeding.

representative." Finally, the DEC and DEP forms cannot be completed and submitted online; instead, the forms must be mailed in or scanned and emailed in. As for DNCP, its form has not changed from what was filed in September. However, as with DEC and DEP, DNCP "does not have a standardized form . . . available electronically online." Nor can a DNCP customer "complete and submit a written consent . . . on line[;]" instead, customers must telephone DNCP and request the paper form.

The Commission should help advance data access (and the third-party innovation it enables) by strongly encouraging the utilities to make their authorization forms available electronically. As Opower's report states:

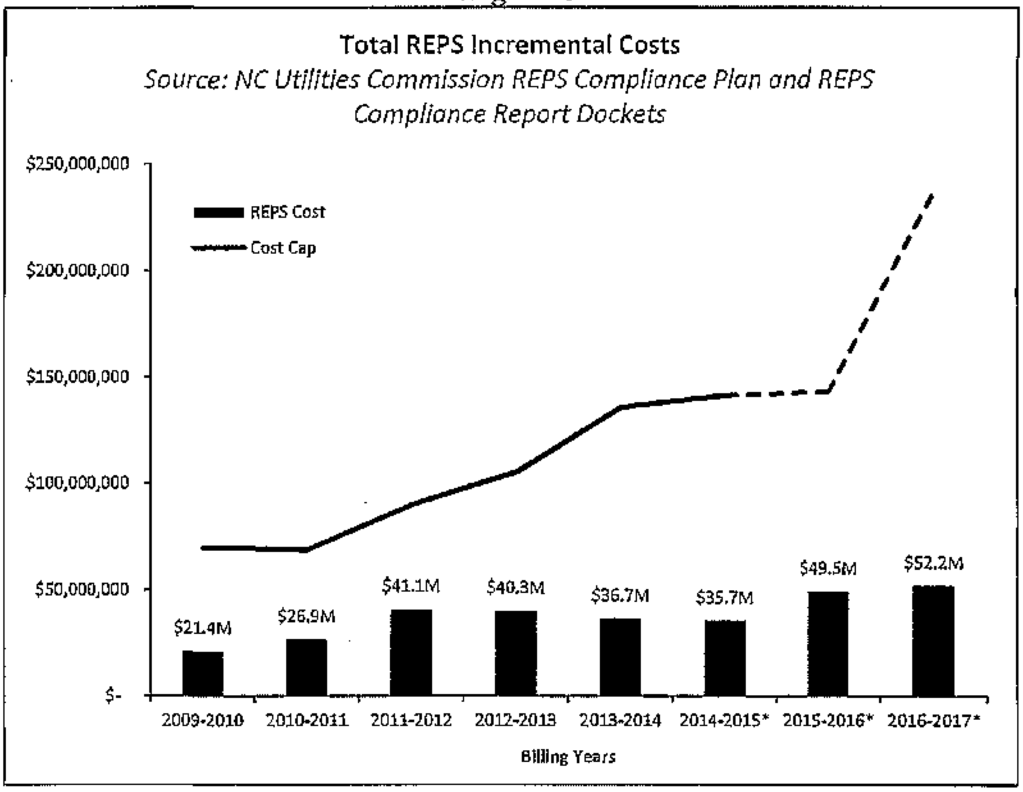
> [C]ompanies as diverse as retail banks and mobile phone providers have developed robust, multi-channel communication strategies that span postal mail, email, SMS alerts, mobile applications, call centers, physical locations, and of course online tools. *Giving customers the information they want, via the channel of their choice, has become the norm in many consumer industries.* However, very few utilities offer this level of outreach or customer choice.

(p. 8) (emphasis added). The absence of convenient internet access to authorization forms is an impediment to customers desiring to share their usage information with third parties of their choice. Last year, the Commission stated that it "expects the IOUs to provide [customer] information in the available format that is efficient and most convenient to the customer, whether that is . . . in a separate written statement or on the internet." *Order Requesting Additional Information and Declining to Initiate Rulemaking*, p. 8, Commission Docket No. E-100, Sub 137 (23 August 2013) (emphasis added). While the authorization form is not customer data, it too should be made available in a way that is most efficient and convenient to the customer, including availability via the internet.

REPS Compliance Plans

North Carolina's utilities have incurred and, for the foreseeable future, will incur REPS incremental costs well below the statutory cost caps provided for in N.C. Gen. Stat. § 62-133.8. *See* Figure 8 *infra.*

Figure 8[15]



NCSEA has two REPS compliance plan-related requests.

REPS Compliance Plan-Related Arguments

a. *Certifying Review of Past REPS Compliance Plans*

NCSEA's first request relates to the ongoing obligation of the utilities to review past REPS compliance plans and unredact information that no longer constitutes a trade

---

[15] Costs represent compliance costs for DEC, DEP, DNCP, NCEMPA, NCMPA1, and Greenco. *See* Exhibit A (NCSEA Workpaper 5). The "*" beside billing years indicates a reflection of the utilities' projected costs in their REPS Compliance Plans.

secret. Last year, the Commission ordered "[t]hat DEP, DEC and DNCP shall annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret." *Order Granting in Part and Denying in Part Motion for Disclosure*, p. 14, Commission Docket No. E-100, Sub 137 (3 June 2013). In a given year, it is possible that a utility could review its compliance plan from four years earlier and conclude that no changes to its redactions are merited; it is also possible that a utility could forget to conduct the review. It would be difficult, if not impossible, for a member of the public reviewing public filings to tell whether the utility conducted the review or not. NCSEA believes clarity can be provided by requiring the utilities to (a) submit letters containing a one-sentence certification that the 2009 plan review has been conducted in conjunction with the filing of the 2013 REPS compliance plans and (b) include, in future REPS compliance plans, a one-sentence certification that the review has been conducted (if this is not otherwise obvious via the filing of a revised past compliance plan).

b. *Avoided Cost Projections*

NCSEA's second request relates to "Commission Rule R8-67(b)(1)(v), which requires electric power suppliers to include 'the current and projected avoided cost rates for each year' in their REPS compliance plans." *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, p. 38, Commission Docket No. E-100, Sub 136 (21 February 2014). In the Commission's 2012 biennial avoided cost order, the Commission concluded that

> DEC and DEP, in their 2012 REPS Compliance Plans filed in Sub 137, inappropriately reported no change in their avoided costs, showing their avoided cost rates in 2013 and 2014 to be projected to be the same as the

> avoided cost rates approved in Sub 127. Because QFs rely on this information, DEC and DEP henceforth should include actual projected avoided costs rates, as of the date of the REPS compliance filing[,]

id., and, based on this conclusion, ordered

> [t]hat DEC and DEP, in their 2014 REPS Compliance Plan and thereafter, shall include actual projected avoided costs rates as of the date of the compliance filing.

Id. at p. 49.

Given that the first phase of the 2014 biennial avoided cost proceeding will contemplate methodological changes, is set for hearing on 7 July 2014, and will not likely yield an order in time for any methodological changes to be incorporated into the DEC, DEP, and DNCP 2014 REPS compliance plans, NCSEA requests that the utilities be directed to create their 2014 REPS compliance plan projections using the methodological approaches approved in the 2012 biennial avoided cost order, together with a statement (for DEC and DEP) indicating whether the effect of the Joint Dispatch Agreement was incorporated or not.

Respectfully submitted, this the 16 day of May, 2014.

Michael D. Youth
Counsel for NCSEA
N.C. State Bar No. 29533
P.O. Box 6465
Raleigh, NC 27628
(919) 832-7601 Ext. 118
michael@energync.org

CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing Comments, together with any attachments, by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 16 day of ~~April~~ May, 2014.

Michael D. Youth
Counsel for NCSEA
N.C. State Bar No. 29533
P.O. Box 6465
Raleigh, NC 27628
(919) 832-7601 Ext. 118
michael@energync.org

	Duke Energy Carolinas Resource Approaches in 2011-2013 IRPs						Duke Energy Progress Resource Approaches in 2011-2013 IRPs					
	Future Capacity Additions 2011 IRP (planned for 2014-2032)	*Source*	Future Capacity Additions 2012 IRP (planned for 2014-2032)	*Source*	Future Capacity Additions 2013 IRP (planned for 2014-2028)	*Source*	Future Capacity Additions 2011 IRP (planned for 2014-2026)	*Source*	Future Capacity Additions 2012 IRP (planned for 2014-2027)	*Source*	Future Capacity Additions 2013 IRP (planned for 2014-2028)	*Source*
Nuclear	2,384	*DEC 2011 IRP, Table 8.D*, p. 92, Commission Docket No. E-100, Sub 128 (1 September 2011)	2,311	*DEC 2012 IRP, Table 1.A*, p. 16, Commission Docket No. E-100, Sub 137 (4 September 2013)	2,463	*DEC 2013 IRP, Table 1-A*, p. 8, Commission Docket No. E-100, Sub 137 (15 October 2013)	552	*DEP 2011 IRP*, p. 24, Commission Docket No. E-100, Sub 128 (1 September 2011)	552	*DEP 2012 IRP*, p. 25, Commission Docket No. E-100, Sub 137 (4 September 2013)	125	*DEP 2013 IRP, Table 1-A*, p. 8, Commission Docket No. E-100, Sub 137
Natural Gas CC	1,300	*DEC 2011 IRP, Table 8.D*, p. 92, Commission Docket No. E-100, Sub 128 (1 September 2011)	2,100	*DEC 2012 IRP, Table 1.A*, p. 16, Commission Docket No. E-100, Sub 137 (4 September 2013)	1,523	*DEC 2013 IRP, Table 1-A*, p. 8, Commission Docket No. E-100, Sub 137 (15 October 2013)	1,212	*DEP 2011 IRP*, p. 24, Commission Docket No. E-100. Sub 128 (1 September 2011)	3,119	*DEP 2012 IRP*, p. 25, Commission Docket No. E-100, Sub 137 (4 September 2013)	3,291	*DEP 2013 IRP, Table 1-A*, p. 8, Commission Docket No. E-100, Sub 137 (15 October 2013)
Natural Gas CT	2,890	*DEC 2011 IRP, Table 8.D*, p. 92, Commission Docket No. E-100, Sub 128 (1 September 2011)	1,920	*DEC 2012 IRP, Table 1.A*, p. 16, Commission Docket No. E-100, Sub 137 (4 September 2013)	573	*DEC 2013 IRP, Table 1-A*, p. 8, Commission Docket No. E-100, Sub 137 (15 October 2013)	1,182	*DEP 2011 IRP*, p. 24, Commission Docket No. E-100. Sub 128 (1 September 2011)	1,051	*DEP 2012 IRP*, p. 25, Commission Docket No. E-100, Sub 137 (4 September 2013)	529	*DEP 2013 IRP, Table 1-A*, p. 8, Commission Docket No. E-100, Sub 137 (15 October 2013)
Coal	0	*DEC 2011 IRP, Table 8.D*, p. 92, Commission Docket No. E-100. Sub 128 (1 September 2011)	0	*DEC 2012 IRP, Table 1.A*, p. 16, Commission Docket No. E-100, Sub 137 (4 September 2013)	0	*DEC 2013 IRP, Table 1-A*, p. 8, Commission Docket No. E-100, Sub 137 (15 October 2013)	0	*DEP 2011 IRP*, p. 24, Commission Docket No. E-100. Sub 128 (1 September 2011)	0	*DEP 2012 IRP*, p. 25, Commission Docket No. E-100, Sub 137 (4 September 2013)	0	*DEP 2013 IRP, Table 1-A*, p. 8, Commission Docket No. E-100, Sub 137 (15 October 2013)
Renewables (Peak Contribution)	493	*DEC 2011 IRP, Table 5.E*, p. 55, Commission Docket No. E-10, Sub 128 (1 September 2011)	758	*DEC 2012 IRP, Table 8.A*, p. 93, Commission Docket No. E-100, Sub 137 (4 September 2013)	921	*DEC 2013 IRP, Table 5-A*, p. 18, Commission Docket No. E-100, Sub 137 (15 October 2013)	39	*DEP 2011 IRP, Table 1*, p. 26, Commission Docket No. E-100. Sub 128 (1 September 2011)	210	*DEP 2012 IRP*, p. 26, Commission Docket No. E-100, Sub 137 (4 September 2013)	436	*DEP 2013 IRP, Table 5-A*, p. 18, Commission Docket No. E-100, Sub 137 (15 October 2013)
DSM-Summer Peak	986	*DEC 2011 IRP, Table 4.A*, p. 34, Commission Docket No. E-100, Sub 128 (1 September 2011)	1,071	*DEC 2012 IRP, Table 4.A*, p. 39, Commission Docket No. E-100, Sub 137 (4 September 2013)	1,061	*DEC 2013 IRP*, p. 90, Commission Docket No. E-100, Sub 137 (15 October 2013)	389	*DEP 2011 IRP, E-8*, p. 79, Commission Docket No. E-100. Sub 128 (1 September 2011)	336	*DEP 2012 IRP, E-11*, p. 98, Commission Docket No. E-100, Sub 137 (4 September 2013)	484	*DEP 2013 IRP*, p. 79, Commission Docket No. E-100, Sub 137 (15 October 2013)
EE-Summer Peak	727	*DEC 2011 IRP, Table 4.A*, p. 34 Commission Docket No. E-100, Sub 128 (1 September 2011)	1,320	*DEC 2012 IRP, Table 4.A*, p. 39, Commission Docket No. E-100, Sub 137 (4 September 2013)	1,477	*DEC 2013 IRP*, p. 90, Commission Docket No. E-100, Sub 137 (15 October 2013)	669	*DEP 2011 IRP, E-8*, p. 79, Commission Docket No. E-100. Sub 128 (1 September 2011)	444	*DEP 2012 IRP, E-11*, p. 98, Commission Docket No. E-100, Sub 137 (4 September 2013)	603	*DEP 2013 IRP, Table C-4 and C-6*, pp. 61-63, Commission Docket No. E-100, Sub 137 (15 October 2013)

Nameplate (MW) Renewable Capacity by Resource Base Case				
	Duke Energy Carolinas			Duke Energy Progress
Source	*DEC 2011 IRP, Table 5.E,* p. 55, Commission Docket No. E-100, Sub 128 (1 September 2011)	*DEC 2012 IRP, Table 1.A,* p. 16, Commission Docket No. E-100, Sub 137 (4 September 2012)	*DEC 2013 IRP,* p. 18, Commission Docket No. E-100, Sub 137 (15 October 2013)	*DEP 2013 IRP,* p. 18, Commission Docket No. E-100, Sub 137 (15 October 2013)
Year	Solar	Solar	Solar	Solar
2014	24	135	294	120
2015	42	253	519	120
2016	45	320	569	120
2017	45	352	609	120
2018	49	398	730	142
2019	51	471	845	156
2020	56	495	957	203
2021	51	538	1,052	248
2022	57	649	1,142	293
2023	72	692	1,229	340
2024	73	736	1,309	385
2025	73	840	1,424	430
2026	81	885	1,499	476
2027	73	928	1,554	524
2028	74	946	1,689	485
2029	82	965	-	-
2030	82	984	-	-
2031	82	1,004	-	-
2032	-	1,004	-	-

DEC 2011 IRP Base Case			
	DEC 2011 IRP, p. 34, Commission Docket No. E-100, Sub 128 (1 September 2011)		*DEC 2011 IRP*, *Table 3.E*, p. 21, Commission Docket No. E-100, Sub 128 (1 September 2011)
	A	(A/B)	B
Year	EE Energy	% of Load	System Sales w/o EE (MWh)
2012	601,792	0.6%	93,281,000
2016	2,008,940	2.0%	102,481,000
2020	3,937,401	3.5%	111,873,000
2024	4,655,623	3.9%	119,235,000
2028	4,990,171	3.9%	127,025,000

DEC 2011 IRP High Case			
	DEC 2011 IRP, *Table 4.B*, p. 35, Commission Docket No. E-100, Sub 128 (1 September 2011)		*DEC 2011 IRP*, *Table 3.E*, p. 21, Commission Docket No. E-100, Sub 128 (1 September 2011)
	G	(G/H)	H
Year	EE Energy	% of Load	System Sales w/o EE (MWh)
2012	601,792	0.6%	93,281,000
2016	2,809,117	2.7%	102,481,000
2020	5,765,231	5.2%	111,873,000
2024	8,721,341	7.3%	119,235,000
2028	11,677,451	9.2%	127,025,000

DEC 2012 IRP Base Case			
	DEC 2012 IRP, *Table 4.A*, p. 39, Commission Docket No. E-100, Sub 137 (4 September 2012)		*DEC 2012 IRP*, *Table 3.E*, p. 25, Commission Docket No. E-100, Sub 137 (4 September 2012)
	C	(C/D)	D
Year	EE Energy	% of Load	System Sales w/o EE (MWh)
2012	1,471,184	1.6%	90,572,000
2016	3,047,522	3.1%	99,147,000
2020	4,879,948	4.5%	108,141,000
2024	6,712,374	5.8%	115,894,000
2028	8,544,800	6.9%	124,352,000

DEC 2012 IRP High Case			
	DEC 2012 IRP, *Table 4.B*, p. 40, Commission Docket No. E-100, Sub 137 (4 September 2012)		*DEC 2012 IRP*, *Table 3.E*, p. 25, Commission Docket No. E-100, Sub 137 (4 September 2012)
	I	(I/J)	J
Year	EE Energy	% of Load	System Sales w/o EE (MWh)
2012	1,471,184	1.6%	90,572,000
2016	4,173,219	4.2%	99,147,000
2020	7,572,072	7.0%	108,141,000
2024	11,111,672	9.6%	115,894,000
2028	14,796,419	11.9%	124,352,000

DEC 2013 IRP Base Case			
	DEC 2013 IRP, p. 90, Commission Docket No. E-100, Sub 137 (15 October 2013)		*DEC 2013 IRP*, p. 70, Commission Docket No. E-100, Sub 137 (15 October 2013)
	E	(E/F)	F
Year	EE Energy	% of Load	System Sales w/o EE
2012	1,471,184	1.6%	90,572,000
2016	1,824,144	1.9%	98,023,000
2020	4,260,057	4.0%	106,904,000
2024	6,682,978	5.8%	114,471,000
2028	8,683,743	7.1%	122,243,000

DEC 2013 IRP High Case			
	NCSEA DR1, Item No. 1-9, Page 1 of 1, Commission Docket No. E-100, Sub 137		*NCSEA DR1, Item No. 1-8, Page 1 of 1*, Commission Docket No. E-100, Sub 137
	K	(K/L)	L
Year	EE Energy	% of Load	System Sales w/o EE
2012	1,471,184	1.6%	90,572,000
2016	2,504,114	2.6%	98,023,000
2020	5,848,871	5.5%	106,904,000
2024	9,327,087	8.1%	114,471,000
2028	12,942,843	10.6%	122,243,000

NCSEA's DR listed in the tables above is attached at the end of the Workpapers.

DEP 2011 IRP Base Case			
	DEP 2011 IRP, p. 8, Commission Docket No. E-100, Sub 128 (1 September 2011)		*DEP 2011 IRP, p. 8, Commission Docket No. E-100, Sub 128 (1 September 2011)*
	A	(A/B)	B
Year	EE Energy	% of Load	System Sales w/o EE (MWh)
2011	328,927	0.5%	63,708,226
2016	1,107,365	1.6%	68,259,825
2021	1,842,266	2.5%	72,570,646
2026	2,739,957	3.6%	76,607,711

DEP 2012 IRP Base Case			
	DEP 2012 IRP, p. 9, Commission Docket No. E-100, Sub 137 (4 September 2012)		*DEP 2012 IRP, p. 9,* Commission Docket No. E-100, Sub 137 (4 September 2012)
	C	(C/D)	D
Year	EE Energy	% of Load	System Sales w/o EE
2011	328,927	0.5%	64,037,153
2016	1,190,332	1.7%	68,710,361
2021	2,134,878	2.9%	73,369,196
2026	3,026,108	3.9%	78,116,005

DEP 2013 IRP Base Case			
	DEP 2013 IRP, p. 79, Commission Docket No. E-100, Sub 137 (15 October 2013)		*DEP 2013 IRP, Table C-4, p. 61,* Commission Docket No. E-100, Sub 137 (15 October 2013)
	E	(E/F)	F
Year	DSM/EE & DSDR	% of Load	System Sales w/o EE
2011	328,927	0.5%	64,037,153
2016	990,876	1.5%	68,141,000
2021	2,190,879	3.0%	73,975,000
2026	3,352,066	4.2%	80,252,000

DEP 2012 IRP High Case			
	DEP's 2012 "high" case projections were obtained during 2012 IRP discovery		*DEP 2012 IRP, p. 9,* Commission Docket No. E-100, Sub 137 (4 September 2012)
	G	(G/H)	H
Year	EE Energy	% of Load	System Sales w/o EE
2011	328,927	0.5%	64,037,153
2016	2,087,000	3.0%	68,710,361
2021	4,484,000	6.1%	73,369,196
2026	6,583,000	8.4%	78,116,005

DEP 2013 IRP High Case			
	NCSEA DR1, Item No. 1-9, Page 1 of 1, Commission Docket No. E-100, Sub 137 (15 October 2013)		*NCSEA DR1, Item No. 1-8, Page 1 of 1,* Commission Docket No. E-100, Sub 137 (15 October 2013)
	I	(I/J)	J
Year	DSM/EE & DSDR	% of Load	System Sales w/o EE
2011	328,927	0.5%	64,037,153
2016	1,662,555	2.4%	68,141,000
2021	4,075,098	5.5%	73,975,000
2026	6,634,530	8.3%	80,252,000

NCSEA's DR listed in the tables above is attached at the end of the Workpapers.

Duke Energy Carolinas
North Carolina REPS Incremental Cost Comparison

		A		B		C		D=(A+B)	
Compliance Year	Billing Period	Total Incremental Costs (Billing Period)	*Source*	Total Test (EMF) Period Over/Under Recovery	*Source*	Cost Cap	*Source*	Total Incremental Cost	*Source*
2008	September 1, 2009 - August 31, 2010	$1,375,973	*Second Revised McManeus Exhibit No. 3, Page 2 of 3,* Commission Docket No. E-7, Sub 872 (24 September 2009)	$2,824,898	*Second Revised McManeus Exhibit No. 3, Page 1 of 3,* Commission Docket No. E-7, Sub 872 (24 September 2009)	$31,697,079	*Second Revised McManeus Exhibit No. 3, Page 2 of 3,* Commission Docket No. E-7, Sub 872 (24 September 2009)	$4,200,871	-
2009	September 1, 2010 - August 31, 2011	$6,111,683	*Order Approving REPS and REPS EMF Rider,* p. 5, Commission Docket No. E-7, Sub 936 (13 August 2010)	$3,267,325	*Order Approving REPS and REPS EMF Rider,* p. 5, Commission Docket No. E-7, Sub 936 (13 August 2010)	$30,991,960	*Duke Energy Carolinas, LLC 2009 REPS Compliance Report,* Smith Exhibit No. 1, p. 5, Commission Docket No. E-7, Sub 936 (2 March 2010)	$9,379,008	-
2010	September 1, 2011 - August 31, 2012	$13,109,241	*Order Approving REPS and REPS EMF Riders and 2010 REPS Compliance,* p. 4, Commission Docket No. E-7, Sub 984 (23 August 2011)	$3,636,122	*Order Approving REPS and REPS EMF Riders and 2010 REPS Compliance,* p. 4, Commission Docket No. E-7, Sub 984 (23 August 2011)	$32,065,620	*Duke Energy Carolinas, LLC 2010 REPS Compliance Report, Felt Exhibit No. 1,* p. 4, Commission Docket No. E-7, Sub 984 (11 March 2011)	$16,745,363	-
2011	September 1, 2012- August 31, 2013	$13,359,907	*Order Approving REPS and REPS EMF Riders and 2011 REPS Compliance,* p. 4, Commission Docket No. E-7, Sub 1008 (16 August 2012)	$197,365	*Order Approving REPS and REPS EMF Riders and 2011 REPS Compliance,* p. 4, Commission Docket No. E-7, Sub 1008 (16 August 2012)	$46,624,570	*Smith Exhibit No. 3, Page 1 of 2,* Commission Docket No. E-7, Sub 1008 (12 March 2012)	$13,557,272	-
2012	September 1, 2013- August 31, 2014	$13,547,264	*Order Approving REPS and REPS EMF Riders and 2012 REPS Compliance,* p. 5, Commission Docket No. E-7, Sub 1034 (20 August 2013)	-$5,105,735	*Order Approving REPS and REPS EMF Riders and 2012 REPS Compliance,* p. 5, Commission Docket No. E-7, Sub 1034 (20 August 2013)	$58,237,362	*Williams Exhibit No. 3, Page 2 of 3,* Commission Docket No. E-7, Sub 1034 (13 March 2013)	$8,441,529	-
2013*	September 1, 2014- August 31, 2015	-	-	-	-	$63,600,083	*DEC 2013 IRP, Table 5,* p. 145, Commission Docket No. E-100, Sub 137 (15 October 2013)	$8,278,714	*DEC 2013 IRP, Table 5,* p. 145, Commission Docket No. E-100, Sub 137 (15 October 2013)
2014*	September 1, 2015- August 31, 2016	-	-	-	-	$64,543,124	*DEC 2013 IRP, Table 5,* p. 145, Commission Docket No. E-100, Sub 137 (15 October 2013)	$12,129,777	*DEC 2013 IRP, Table 5,* p. 145, Commission Docket No. E-100, Sub 137 (15 October 2013)
2015*	September 1, 2016- August 31, 2017	-	-	-	-	$106,425,364	*DEC 2013 IRP, Table 5,* p. 145, Commission Docket No. E-100, Sub 137 (15 October 2013)	$14,582,132	*DEC 2013 IRP, Table 5,* p. 145, Commission Docket No. E-100, Sub 137 (15 October 2013)

* Utilities projected cost in REPS Compliance Plans

Duke Energy Progress North Carolina REPS Incremental Cost Comparison									
		E		F		G		H=(E+F)	
Compliance Year	Billing Period	Total Incremental Costs (Billing Period)	*Source*	Total Test (EMF) Period Over/Under Recovery	*Source*	Cost Cap	*Source*	Total Incremental Cost	*Source*
2008	December 1, 2009-November 30, 2010	$13,913,741	*Order Approving REPS and REPS EMF Riders*, p. 3, Commission Docket No. E-2, Sub 948 (12 November 2009)	$1,655,711	*Order Approving REPS and REPS EMF Riders*, p. 3, Commission Docket No. E-2, Sub 948 (12 November 2009)	$20,402,501	*Fonvielle Exhibit 1*, Commission Docket No. E-2, Sub 948 (18 May 2009)	$15,569,452	-
2009	December 1, 2010-November 30, 2011	$14,484,441	*Order Approving REPS and REPS EMF Riders*, p. 4, Commission Docket No. E-2, Sub 974 (17 November 2010)	-$196,457	*Order Approving REPS and REPS EMF Riders*, p. 4, Commission Docket No. E-2, Sub 974 (17 November 2010)	$20,992,940	*Ellis Revised Exhibit No 3.*, Page 2, Commission Docket No. E-2, Sub 974 (20 August 2010)	$14,287,984	-
2010	December 1, 2011-November 30, 2012	$22,237,600	*Order Approving REPS and REPS EMF Riders and 2010 REPS Compliance*, p. 4, Commission Docket No. E-2, Sub 1000 (10 November 2011)	$434,948	*Order Approving REPS and REPS EMF Riders and 2010 REPS Compliance*, p. 4, Commission Docket No. E-2, Sub 1000 (10 November 2011)	$41,148,111	*Foster Exhibit No. 3, Page 2*, Commission Docket No. E-2, Sub 1000 (3 June 2011)	$22,672,548	-
2011	December 1, 2012-November 30, 2013	$18,746,453	*Order Approving REPS and REPS EMF Riders and 2011 REPS Compliance*, p. 4, Commission Docket No. E-2, Sub 1020 (16 November 2012)	$2,519,486	*Order Approving REPS and REPS EMF Riders and 2011 REPS Compliance*, p. 4, Commission Docket No. E-2, Sub 1020 (16 November 2012)	$41,887,788	*Ellis Exhibit No. 3, Page 1*, Commission Docket No. E-2, Sub 1020 (4 June 2012)	$21,265,939	-
2012	December 1, 2013-November 30, 2014	$21,558,084	*Order Approving REPS and REPS EMF Riders and 2012 REPS Compliance*, p. 4,Commission Docket No. E-2, Sub 1032 (25 November 2013)	-$986,645	*Revised Williams Exhibit No. 1*, Commission Docket No. E-2, Sub 1032 (29 August 2013)	$42,708,052	*Byrd Exhibit No. 1*, Commission Docket No. E-2, Sub 1032 (12 June 2013)	$20,571,439	-
2013*	December 1, 2014-November 30, 2015	-	-	-	-	$42,520,860	*DEP 2013 IRP*, Table 5, p. 149, Commission Docket No. E-100, Sub 137 (15 October 2013)	$20,324,166	*DEP 2013 IRP*, Table 5, p. 149, Commission Docket No. E-100, Sub 137 (15 October 2013)
2014*	December 1, 2015-November 30, 2016	-	-	-	-	$42,825,158	*DEP 2013 IRP*, Table 5, p. 149, Commission Docket No. E-100, Sub 137 (15 October 2013)	$24,016,763	*DEP 2013 IRP*, Table 5, p. 149, Commission Docket No. E-100, Sub 137 (15 October 2013)
2015*	December 1, 2016-November 30, 2017	-	-	-	-	$68,889,101	*DEP 2013 IRP*, Table 5, p. 149, Commission Docket No. E-100, Sub 137 (15 October 2013)	$21,797,340	*DEP 2013 IRP*, Table 5, p. 149, Commission Docket No. E-100, Sub 137 (15 October 2013)

* Utilities projected cost in REPS Compliance Plans

Dominion North Carolina Power

North Carolina REPS Incremental Cost Comparison

		I		J		K		L=(I+J)	
Compliance Year	Billing Period	Total Incremental Costs (Billing Period)	*Source*	Total Test (EMF) Period Over/Under Recovery	*Source*	Cost Cap	*Source*	Total Incremental Cost	*Source*
2012	January 1, 2014 - December 31, 2014	$879,731	*Order Approving REPS and REPS EMF Riders and 2012 REPS Compliance*, p. 4, Commission Docket No. E-22, Sub 503 (18 December 2013)	$797,661	*Order Approving REPS and REPS EMF Riders and 2012 REPS Compliance*, p. 4, Commission Docket No. E-22, Sub 503 (18 December 2013)	$3,848,626	*Direct Testimony and Exhibits of Muchhala, Courts, Givens and Rice*, p. 5, Commission Docket No. E-22, Sub 503 (29 August 2013)	$1,677,392	-
2013*	-	-	-	-	-	$3,868,370	*DNCP 2013 IRP*, Figure 1.8.1, p. 15, Commission Docket No. E-100, Sub 137 (30 August 2013)	$546,115	*DNCP 2013 IRP*, Figure 1.8.1, p. 15, Commission Docket No. E-100, Sub 137(30 August 2013)
2014*	-	-	-	-	-	$4,112,426	*DNCP 2013 IRP*, Figure 1.8.1, p. 15, Commission Docket No. E-100, Sub 137 (30 August 2013)	$1,443,347	*DNCP 2013 IRP*, Figure 1.8.1, p. 15, Commission Docket No. E-100, Sub 137(30 August 2013)
2015*	-	-	-	-	-	$6,547,470	*DNCP 2013 IRP*, Figure 1.8.1, p. 15, Commission Docket No. E-100, Sub 137 (30 August 2013)	$1,467,387	*DNCP 2013 IRP*, Figure 1.8.1, p. 15, Commission Docket No. E-100, Sub 137(30 August 2013)

* Utilities projected cost in REPS Compliance Plans

NCEMPA

North Carolina REPS Incremental Cost Comparison

	M		N	
Compliance Year	Incremental Cost	*Source*	Cost Cap	*Source*
2008	$0	*NCEMPA's Revised 2008 REPS Compliance Report*, p. 4, Commission Docket No. E-100, Sub 131 (31 August 2011)	$4,445,770	*NCEMPA's Revised 2008 REPS Compliance Report*, p. 4, Commission Docket No. E-100, Sub 131 (31 August 2011)
2009	$0	*NCEMPA's Revised 2009 REPS Compliance Report*, p. 4, Commission Docket No. E-100, Sub 131 (31 August 2011)	$4,462,770	*NCEMPA's Revised 2009 REPS Compliance Report*, p. 5, Commission Docket No. E-100, Sub 131 (31 August 2011)
2010	$493,185	*NCEMPA's 2010 REPS Compliance Report (Redacted)*, p. 5, Commission Docket No. E-100, Sub 131 (31 August 2011)	$4,483,690	*NCEMPA's 2010 REPS Compliance Report (Redacted)*, p. 6, Commission Docket No. E-100, Sub 131 (31 August 2011)
2011	$460,090	*NCEMPA's 2011 REPS Compliance Report - Public Version*, p. 6, Commission Docket No. E-100, Sub 135 (30 August 2012)	$4,486,330	*NCEMPA's 2011 REPS Compliance Report - Public Version*, p. 6, Commission Docket No. E-100, Sub 135 (30 August 2012)
2012	$951,890	*NCEMPA's REPS Compliance Report for 2012*, p. 6, Commission Docket No. E-100, Sub 139 (26 August 2013)	$8,958,140	*NCEMPA's REPS Compliance Report for 2012*, p. 7, Commission Docket No. E-100, Sub 139 (26 August 2013)
2013*	$1,500,000	*NCEMPA's REPS Compliance Plan for 2013 to 2015*, p. 15, Commission Docket No. E-100, Sub 139 (26 August 2013)	$9,000,000	*NCEMPA's REPS Compliance Plan for 2013 to 2015*, p. 15, Commission Docket No. E-100, Sub 139 (26 August 2013)
2014*	$1,900,000	*NCEMPA's REPS Compliance Plan for 2013 to 2015*, p. 15, Commission Docket No. E-100, Sub 139 (26 August 2013)	$9,100,000	*NCEMPA's REPS Compliance Plan for 2013 to 2015*, p. 15, Commission Docket No. E-100, Sub 139 (26 August 2013)
2015*	$2,400,000	*NCEMPA's REPS Compliance Plan for 2013 to 2015*, p. 15, Commission Docket No. E-100, Sub 139 (26 August 2013)	$14,300,000	*NCEMPA's REPS Compliance Plan for 2013 to 2015*, p. 15, Commission Docket No. E-100, Sub 139 (26 August 2013)

* Utilities projected cost in REPS Compliance Plans

NCMPA1 North Carolina REPS Incremental Cost Comparison				
	O		P	
Compliance Year	Incremental Cost	*Source*	Cost Cap	*Source*
2008	$230,613	*NCMPA Number 1's 2008 REPS Compliance Report*, p. 5, Docket No. E-100, Sub 125 (31 August 2009)	$2,974,660	*Order on 2008 REPS Compliance Report*, p. 4, Commission Docket No. E-43, Sub 6 (3 May 2011)
2009	$466,006	*North Carolina Eastern Municipal Power Agency 1's 2009 Compliance Report*, p. 4, Commission Docket No. E-100, Sub 129 (1 September 2010)	$2,920,550	*North Carolina Eastern Municipal Power Agency 1's 2009 Compliance Report*, p. 5, Commission Docket No. E-100, Sub 129 (1 September 2010)
2010	$1,156,489	*NCMPA1's 2010 REPS Compliance Report*, p. 4, Commission Docket No. E-100, Sub 131 (31 August 2011)	$2,915,050	*NCMPA1's 2010 REPS Compliance Report*, p. 5, Commission Docket No. E-100, Sub 131 (31 August 2011)
2011	$2,239,244	*NCMPA1's 2011 REPS Compliance Report - Public Version*, p. 5, Commission Docket No. E-100, Sub 135 (30 August 2012)	$2,916,040	*NCMPA1's 2011 REPS Compliance Report - Public Version*, p. 6, Commission Docket No. E-100, Sub 135 (30 August 2012)
2012	$1,079,918	*NCMPA1's REPS Compliance Report for 2012*, p. 6, Commission Docket No. E-100, Sub 139 (26 August 2013)	$6,117,760	*NCMPA1's REPS Compliance Report for 2012*, p. 7, Commission Docket No. E-100, Sub 139 (26 August 2013)
2013*	$1,700,000	*NCMPA1's REPS Compliance Plan for 2013 Through 2015*, p. 19, Commission Docket No. E-100, Sub 139 (26 August 2013)	$6,200,000	*NCMPA1's REPS Compliance Plan for 2013 Through 2015*, p. 19, Commission Docket No. E-100, Sub 139 (26 August 2013)
2014*	$1,600,000	*NCMPA1's REPS Compliance Plan for 2013 Through 2015*, p. 19, Commission Docket No. E-100, Sub 139 (26 August 2013)	$6,200,000	*NCMPA1's REPS Compliance Plan for 2013 Through 2015*, p. 19, Commission Docket No. E-100, Sub 139 (26 August 2013)
2015*	$1,600,000	*NCMPA1's REPS Compliance Plan for 2013 Through 2015*, p. 19, Commission Docket No. E-100, Sub 139 (26 August 2013)	$9,200,000	*NCMPA1's REPS Compliance Plan for 2013 Through 2015*, p. 19, Commission Docket No. E-100, Sub 139 (26 August 2013)

* Utilities projected cost in REPS Compliance Plans

Greenco Solutions North Carolina REPS Incremental Cost Comparison				
	Q		R	
Compliance Year	Incremental Cost	*Source*	Cost Cap	*Source*
2008	$1,424,751	*Order Approving 2008 REPS Compliance Report*, p. 4, Commission Docket No. EC-83, Sub 1 (3 May 2011)	$10,273,260	*Order Approving 2008 REPS Compliance Report*, p. 3, Commission Docket No. EC-83, Sub 1 (3 May 2011)
2009	$2,814,955	*GreenCo Solutions 2009 Compliance Report/ 2010 Compliance Plan (Public Version)*, p. 7, Commission Docket No. E-100, Sub 128 (1 September 2010)	$9,253,620	*GreenCo Solutions 2009 Compliance Report/ 2010 Compliance Plan (Public Version)*, p. 6, Commission Docket No. E-100, Sub 128 (1 September 2010)
2010	Withheld	*GreenCo Solutions, Inc.'s (Public Version) 2011 Compliance Plan and 2010 Compliance Report*, p. 9, Commission Docket No. E-100, Sub 131 (19 September 2011)	$9,127,820	GreenCo Solutions, Inc.'s (Public Version) 2011 *Compliance Plan and 2010 Compliance Report*, p. 13, Commission Docket No. E-100, Sub 131 (19 September 2011)
2011	$2,735,731	*GreenCo Solutions, Inc.'s 2011 REPS Compliance Report - Public Version*, p. 5, Commission Docket No. E-100, Sub 135 (4 September 2012)	$9,242,930	*GreenCo Solutions, Inc.'s 2011 REPS Compliance Report - Public Version*, p. 5, Commission Docket No. E-100, Sub 135 (4 September 2012)
2012	$3,971,769	*Greenco Solution, Inc.'s (Public) 2012 REPS Compliance Plan*, p. 11, Commission Docket No. E-100, Sub 137 (4 September 2012)	$15,889,310	*Greenco Solution, Inc.'s (Public) 2012 REPS Compliance Plan*, p. 12, Commission Docket No. E-100, Sub 137 (4 September 2012)
2013*	$3,357,237	*GreenCo Solutions, Inc. 2013 REPS Compliance Plan*, p. 19, Commission Docket No. E-100, Sub 139 (3 September 2013)	$16,079,856	*GreenCo Solutions, Inc. 2013 REPS Compliance Plan*, p. 19, Commission Docket No. E-100, Sub 139 (3 September 2013)
2014*	$8,407,255	*GreenCo Solutions, Inc. 2013 REPS Compliance Plan*, p. 19, Commission Docket No. E-100, Sub 139 (3 September 2013)	$16,296,948	*GreenCo Solutions, Inc. 2013 REPS Compliance Plan*, p. 19, Commission Docket No. E-100, Sub 139 (3 September 2013)
2015*	$10,378,257	*GreenCo Solutions, Inc. 2013 REPS Compliance Plan*, p. 19, Commission Docket No. E-100, Sub 139 (3 September 2013)	$31,864,860	*GreenCo Solutions, Inc. 2013 REPS Compliance Plan*, p. 19, Commission Docket No. E-100, Sub 139 (3 September 2013)

* Utilities projected cost in REPS Compliance Plans

Total Cost of the North Carolina REPS		
Compliance Year	Total Incremental Cost	Total Cost Cap
	(D+H+L+M+O+Q)	(C+G+K+N+P+R)
2008	$21,425,687	$69,793,270
2009	$26,947,953	$68,621,840
2010	$21,067,585	$89,735,291
2011	$40,258,276	$105,157,658
2012	$36,687,937	$135,754,250
2013*	$35,706,232	$141,269,169
2014*	$49,497,142	$143,077,656
2015*	$52,225,116	$287,226,795

* Utilities projected cost in REPS Compliance Plans

DUKE ENERGY CAROLINAS

Request:

Please provide the quantitative data underlying the load impacts of energy efficiency and demand-side management programs, annual energy savings, for the:

a. Environmental Focus Scenario
b. Joint Planning Scenario

The data I am looking for is comparable to the table, Base Case Load Impacts of EE and DSM Programs, on page 90 of this filing.

Response:

a. Please see the attached spreadsheet labeled "NCSEA DR1 - Q9a - DEC.xlsx"

NCSEA DR1 - Q9a - DEC.xlsx

b. The Joint Planning Scenario used the energy efficiency and demand-side management information from the Base Case forecast already included in the IRP document and referenced in this Data Request question.

NCSEA
Docket No. E-100, Sub 137
NCSEA Data Request
Duke Energy Carolinas

Question 9a

Year	Annual Energy Savings, MWh Gross of Free Riders, At Generator Environmental Focus Scenario
2013	435,988
2014	875,988
2015	1,686,380
2016	2,504,114
2017	3,328,614
2018	4,160,503
2019	5,000,452
2020	5,848,871
2021	6,705,725
2022	7,571,089
2023	8,444,834
2024	9,327,087
2025	10,217,794
2026	11,117,307
2027	12,025,639
2028	12,942,843

DUKE ENERGY CAROLINAS

Request:

Please provide the quantitative data underlying the load forecast without energy efficiency programs for the:

a. Environmental Focus Scenario
b. Joint Planning Scenario

The data I am looking for is comparable to the data found in Table C-4, Load Forecast without Energy Efficiency Programs, on page 70 of this filing.

Response:

a. The load forecast without energy efficiency is the same for the Environmental Focus Scenario as it is for the Base Case. The Environmental Focus Scenario differs from the Base Case by utilizing higher renewable energy and EE projections than used in the Base Case.

b. The Joint Planning Scenario also utilizes the same load forecasts utilized in the Base Scenario. The difference in the Joint Planning Scenarios is that the DEC and DEP load forecasts are additive to represent the load of the entire DEC/DEP region.

NCSEA
Docket No. E-100, Sub 137
NCSEA DR1
Integrated Resource Plans
Item No. 1-9

DUKE ENERGY PROGRESS

<u>Request</u>:

Please provide the quantitative data underlying the energy efficiency and demand-side management programs annual energy savings for the:

a. Environmental Focus Scenario
b. Joint Planning Scenario

The data I am looking for is comparable to the data found in the table, Annual MWh Energy Savings for Post SB-3 DSM/EE (at generator), on page 79 of this filing.

<u>Response</u>:

a. Please see the attached spreadsheet labeled "NCSEA DR1 - Q9a - DEP.xlsx".

NCSEA DR1 - Q9a - DEP.xlsx

b. The Joint Planning Scenario used the energy efficiency and demand-side management information from the Base Case forecast already included in the IRP document and referenced in this Data Request question.

NCSEA
Docket No. E-100, Sub 137
NCSEA Data Request
Duke Energy Progress

Question 9a

Year	Annual Energy Savings, MWh Gross of Free Riders, At Generator Environmental Focus Scenario
2013	210,013
2014	735,013
2015	1,197,124
2016	1,662,555
2017	2,134,042
2018	2,611,362
2019	3,093,790
2020	3,581,539
2021	4,075,098
2022	4,574,712
2023	5,080,491
2024	5,592,504
2025	6,110,621
2026	6,634,530
2027	7,163,749
2028	7,697,756

NCSEA
Docket No. E-100, Sub 137
NCSEA DR1
Integrated Resource Plans
Item No. 1-8
Page 1 of 1

DUKE ENERGY PROGRESS

Request:

Please provide the quantitative data underlying the load forecast without energy efficiency programs for the:

a. the Environmental Focus Scenario
b. the Joint Planning Scenario

The data I am looking for is comparable to the data found in Table C-4, Load forecast without Energy Efficiency Programs, on page 61of this filing.

Response:

a. The load forecast without energy efficiency is the same for the Environmental Focus Scenario as it is for the Base Case. The Environmental Focus Scenario differs from the Base Case by utilizing higher renewable energy and EE projections than used in the Base Case.

b. The Joint Planning Scenario also utilizes the same load forecast utilized in the Base Scenario. The difference in the Joint Planning Scenarios is that the DEC and DEP load forecasts are additive to represent the load of the entire DEC/DEP region.

DUKE ENERGY CAROLINAS, LLC
Response to NCSEA Request
NCSEA PEC 3-3

Docket No. E-100, Sub 137

Date of Request: 11/8/2012
Response Dated: 11/28/2012

CONFIDENTIAL:
☐ YES
☒ No

(Provided Pursuant to Confidentiality Agreement)

The attached response was consolidated and prepared under my supervision.

Kendal Bowman
Name

Associate General Counsel
Title

550 South Tryon Street, Charlotte, NC 2802
Business address

Request Number: NCSEA PEC 3-3

Request:
On page A-12, two graphs show PEC's high and low case DSM capacity and energy impacts, but do not list each year's impacts. Please provide numerical, annual estimates of the low- and high-case DSM/EE capacity and energy impacts for PEC's service territory, broken out by North Carolina and South Carolina jurisdictions.

Response:

The base case energy efficiency (EE) savings projection and high case EE sensitivity for the PEC system are provided in the table below. PEC does not have this information broken out by state.

Note that the second chart on page A-12 of the IRP (Energy Efficiency – Annual Energy Reduction) is incorrect. The table below contains the correct data. In addition, a corrected version of page A-12 is included with this response document in file "NCSEA PEC 3-3 corrected page A-12.pdf".

	Base Case EE Savings		High Case EE Savings	
	Summer	GWh	Summer	GWh
Year	Peak MW	Energy	Peak MW	Energy
2013	100	626	128	808
2014	127	794	187	1,178
2015	154	975	257	1,629
2016	182	1,167	326	2,087
2017	206	1,320	399	2,552
2018	227	1,494	460	3,024
2019	251	1,688	521	3,504
2020	278	1,895	585	3,990
2021	306	2,108	650	4,484
2022	334	2,315	715	4,962
2023	361	2,515	778	5,423
2024	386	2,707	837	5,865
2025	409	2,860	889	6,217
2026	428	2,997	933	6,533
2027	444	3,117	971	6,809
2028	459	3,218	1,004	7,042
2029	470	3,300	1,031	7,229
2030	479	3,351	1,050	7,347
2031	483	3,375	1,060	7,400