STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 137

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2012 Biennial Integrated Resource Plans and Related 2012 REPS Compliance Plans	))))	ORDER APPROVING INTEGRATED RESOURCE PLANS AND REPS COMPLIANCE PLANS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on February 11, 2013

Courtroom 5310, Mecklenburg County Courthouse, 832 E. Fourth Street, Charlotte, North Carolina on February 28, 2013

BEFORE: Commissioner Bryan E. Beatty, Presiding; Chairman Edward S. Finley, Jr., and Commissioners William T. Culpepper, III, Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

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For North Carolina Waste Awareness & Reduction Network, Blue Ridge Environmental Defense League, and Greenpeace:

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BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to G.S. 62-110.1 is included in the Rule as a part of the IRP process.

General Statute (G.S.) 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, G.S. 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, G.S. 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: (1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to G.S. 62-110.1.

G.S. 62-2(a)(3a) declares it a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills . . . .

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended G.S. 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[1]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[2] EE measures do not include DSM.

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources (collectively, the utilities),[3] furnish the Commission with a biennial report in even-numbered years that

[1] G.S. 62-133.9(c).

[2] G.S. 62-133.8(a)(2) and (4).

[3] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of G.S. 62-110.1(c) and G.S. 62-42, effective July 1, 2013.

contains the specific information set out in that Rule. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2012 BIENNIAL REPORTS

This Order addresses the 2012 biennial reports (2012 IRPs) filed in Docket No. E-100, Sub 137, by Duke Energy Progress, Inc. (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (DNCP) (collectively, the investor-owned utilities or IOUs), and North Carolina Electric Membership Corporation (NCEMC),[4] Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Haywood EMC (Haywood), and EnergyUnited EMC (EnergyUnited) (collectively, the electric membership corporations or EMCs).[5] In addition, this Order addresses the REPS compliance plans filed by the lOUs, GreenCo,[6] Halifax EMC (Halifax), and EnergyUnited.

As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

[4] NCEMC indicated that it provides wholesale power to 25 of the 26 EMCs in North Carolina and is the full requirements power supplier for 20 of the cooperatives. NCEMC's 2012 IRP is filed on behalf of these 20 members. NCEMC provides partial requirements capacity and energy entitlements to 5 EMCs: Blue Ridge EMC, Rutherford EMC, Piedmont EMC, Haywood EMC, and EnergyUnited (collectively, the independent EMCs). The 26th EMC, French Broad EMC, is not a member of NCEMC and is not required to file an individual IRP, as it has entered into a full requirements contract with DEP.

[5] Blue Ridge EMC contracts with DEC as its full requirements and REPS compliance service provider. Blue Ridge EMC, therefore, is not required to file an IRP.

[6] GreenCo filed a consolidated 2012 REPS compliance plan on behalf of Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, Carteret-Craven EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC.

The following parties intervened in this docket: Blue Ridge Environmental Defense League (BREDL); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Greenpeace; Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Sierra Club; and Southern Alliance for Clean Energy (SACE). The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

PROCEDURAL HISTORY

On August 8, 2012, Rutherford filed a letter indicating that its load would be included in DEC's IRP filing for reporting purposes, and its REPS compliance plan would be reflected in DEC's REPS compliance plan. On August 30, 2012, EnergyUnited filed its 2012 IRP and 2012 REPS compliance plan. On August 31, DNCP filed its 2012 IRP and 2012 REPS compliance plan, and Rutherford filed its 2012 IRP. On September 4, 2012, DEC[7] and DEP filed their 2012 IRPs and 2012 REPS compliance plans, NCEMC filed its 2012 IRP, and GreenCo and Halifax filed their 2012 REPS compliance plans. On September 11, 2012, Piedmont filed its 2012 IRP, and on September 13, 2012, Haywood filed its 2012 IRP. On November 11, 2012, DNCP filed an amendment to its 2012 IRP.

On October 8, 2012, the Commission issued an Order scheduling a public hearing on the 2012 IRPs and the 2012 REPS compliance plans for February 11, 2013, in Raleigh.

On January 10, 2013, the Public Staff filed a motion requesting that the deadline for the filing of comments on the 2012 IRPs and REPS compliance plans be extended to February 5, 2013, which the Commission granted by Order dated January 15, 2013. This Order also extended the deadline for reply comments to February 19, 2013.

On February 4, 2013, BREDL, Greenpeace, and NC WARN (NC WARN, et al.) submitted their joint comments on the 2012 IRPs. On February 5, 2013, comments on the 2012 IRPs were submitted by the Public Staff, MAREC, NCSEA, and jointly by SACE and the Sierra Club. On February 7, 2013, MAERC filed an amended version of its initial comments.

On February 15, 2013, DEC and DEP filed a motion for extension of time to file reply comments until March 5, 2013, which the Commission granted by Order issued on February 18, 2013.

On March 5, 2013, reply comments were filed by Halifax, Rutherford, SACE, DNCP, EnergyUnited, NCEMC, and jointly by DEC and DEP.

[7] DEC's REPS compliance plan included the REPS compliance plans for Rutherford and Blue Ridge EMC.

On July 15, 2013, the Commission issued an Order which, among other things, called for the filings of proposed orders and briefs in this docket on or before August 26, 2013.

On July 22, 2013, NCSEA filed a partial proposed order limited to the issue of access to electricity consumption data that it had raised in its initial comments.

On August 21, 2013, the Public Staff filed a motion requesting an extension of time to September 9, 2013, for the filing of briefs and proposed orders, which was granted by the Commission on August 22, 2013.

On September 6, 2013, NC WARN, et al., filed its brief. On September 9, 2013, SACE and the Sierra Club filed a joint brief, MAREC filed a brief, and the Public Staff, DNCP, and DEC and DEP jointly filed proposed orders.

NC WARN et al.'s Motion for Additional Public Hearings

On January 9, 2013, NC WARN, et al., filed a motion requesting that the Commission hold additional public hearings in Charlotte and Asheville. NC WARN, et al., stated, among other things, that there was considerable public interest in the IRPs in Charlotte and Asheville, that members of those communities felt it would be a hardship to attend the public hearing in Raleigh, and that a single public hearing would not provide adequate time to hear from all interested persons.

On January 24, 2013, the Commission issued an Order allowing responses to the motion for additional hearings. On January 31, 2013, SACE and the Sierra Club filed a joint response supporting the motion for additional hearings. On February 1, 2013, DEC and DEP filed a joint response stating that there was no need to hold additional IRP public hearings, since several avenues existed for members of the public to express their views about the IRPs, including the public hearing in Raleigh, letters, petitions, and electronic mail. They also stated that NC WARN, et al.'s position on the construction and operation of generating facilities is well documented and additional public hearings would result in needless repetition of the same talking points, and that if the Commission decided to grant NC WARN, et al.'s motion, it should schedule one hearing to be held in a location that is central to both Charlotte and Asheville, such as Hickory.

On February 5 and 6, 2013, the Commission granted NC WARN, et al.'s motion in part by scheduling one public hearing to be held in Charlotte, North Carolina on February 28, 2013.

NC WARN, et al.'s Motion for an Evidentiary Hearing

In their initial joint comments filed on February 4, 2013, NC WARN, et al. requested that the Commission hold an evidentiary hearing on whether the IRPs submitted by DEC and DEP are in the best interest of ratepayers and provide "least cost" electricity. In their initial joint comments, SACE and the Sierra Club indicated their support for an evidentiary hearing and proposed issues on which the Commission might wish to receive pre-filed testimony and conduct a hearing. In their March 5, 2013, reply comments, the IOUs indicated that they did not view NC WARN, et al.'s request for an evidentiary hearing as presenting compelling issues or reasoning in support of such a hearing, and that the request for an evidentiary hearing should be denied.[8]

On May 3, 2013, the Commission issued an Order Requiring Verified Responses in which it noted that during the public hearings, as well as in statements of position regarding this proceeding that were mailed or emailed to the Commission, many citizens questioned whether the IRPs filed by DEC and DEP appropriately reflect the expected growth in demand for electricity, the ability to meet that demand with EE and renewable energy resources, and other aspects of the IRPs. As a result of these concerns, as well as information from other proceedings and forums, the Commission found good cause to require DEC and DEP to provide verified answers on or before Monday, June 10, 2013, to 19 questions listed on Attachment A to its Order. The topics covered by the questions included EE, DSM, renewable energy, tiered electric rates, public benefit loan funding, solar generation, future EE potential, full compliance with REPS requirements, population growth projections, projected annual retail load growth, generation reserve margins, coal plant emissions and climate change initiatives.

On May 13, 2013, NC WARN, et al., filed a response to the Commission's Order stating, among other things, that the questions included in the Order helped to shed light on several issues not covered in the IRPs. In addition, NC WARN, et al. proposed that two additional questions be added to the list of Commission questions. The proposed questions asked whether DEC and DEP had conducted a study of the potential for using combined heat and power (CHP). Further, NC WARN, et al. stated that it continued to urge the Commission to hold an evidentiary hearing in this docket.

On June 10, 2013, DEC and DEP filed a combined verified response to the Commission's 19 questions.

On July 15, 2013, the Commission issued an Order denying NC WARN, et al.'s motion for an evidentiary hearing. In its Order, the Commission concluded that the substantive issues raised by ratepayers in their testimony and written comments and by the intervenors in their initial comments have been addressed by DEC and DEP in their respective reply comments and in their responses to the Commission's Order Requiring Verified Responses. In addition, the Commission concluded that the record contains sufficient detail to allow the Commission to decide all contested issues without the necessity of a further evidentiary hearing, and that there is not good cause to require DEC and DEP to answer the additional questions proposed by NC WARN, et al.

[8] DEC and DEP reply comments at 11; DNCP reply comments at 13.

NCSEA's Motion for Disclosure

On February 5, 2013, NCSEA filed a motion for disclosure requesting that the Commission require DEC and DEP to make public certain information in their REPS compliance plans that was filed under seal with the Commission as confidential trade secret information. In addition, NCSEA requested that the Commission order DEC, DEP, and DNCP to annually review their REPS compliance plans from four years earlier and make public all information that was previously redacted from those plans, or file an explanation of why the information should remain confidential. On February 7, 2013, the Commission issued an Order requesting that interested parties file comments and reply comments in response to NCSEA's motion. On March 7, 2013, initial comments were filed jointly by DEC and DEP. On March 8, 2013, initial comments were filed jointly by SACE and the Sierra Club, and individually by DNCP. On March 25, 2013, NCSEA filed reply comments and on April 1, 2013, DNCP filed reply comments.

On June 3, 2013, the Commission issued an Order granting NCSEA's motion in part by (1) ordering DEP to amend its 2012 REPS compliance plan by filing as public information the specific REPS contract information disclosed in Exhibit 1 of DEP's 2008 and 2010 REPS compliance plans, to the extent that this information has not changed and continues to be a part of DEP's 2012 REPS compliance plan, and further, to include this specific contract information in its subsequent REPS compliance plans under the same guidelines; (2) ordering DEC to amend its 2012 REPS compliance plan by disclosing the information redacted in its 2008 REPS compliance plan, subject to prohibitions in the contracts and after redacting the names of counterparties; (3) ordering DEP, DEC, and DNCP to annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret; and (4) reaffirming the guidelines stated in the Commission's Order Concerning Confidentiality of Report Filings in Docket No. P-100, Sub 133, issued on October 21, 1997, which required parties to submit at the time of filing information under seal a detailed and cogent statement of the reasons the information is a trade secret pursuant to G.S. 132-1, et seq. On July 1, 2013, DEC filed revised 2008 and 2012 REPS compliance plans.

NCSEA Request for Rulemaking

In its initial comments, NCSEA requested that the Commission find that there is an inadequacy of access to customer information, that this inadequacy impedes the greater utilization of DSM/EE, and that the Commission should open a rulemaking docket to expand access to customer data, both to the customers of the electric power suppliers and third parties, such as smart grid technology companies, at the meter level and the aggregate level. NCSEA stated that the rule changes could potentially enable:

(1) Academic and governmental institutions to conduct research, the results of which will help educate society about energy usage;
(2) Businesses to develop and roll out innovative energy usage products and services; and

(3) Customers to exercise greater control over their energy usage and its economic, environmental, and social impacts.[9]

NCSEA stated that Commission Rule R8-51 may be antiquated and not accurately reflect, for example, the availability of more granular data than monthly usage or customer interest in accessing their electricity consumption data via the internet. NCSEA pointed out that the National Association of Regulatory Utility Commissioners (NARUC) and the American Council for an Energy Efficient Economy (ACEEE) have called for promulgation of rules that contemplate such issues, and numerous states have adopted rules that increase the availability of this information while maintaining the privacy of customer information in the absence of disclosure authorization.[10]

In its reply comments, DNCP disputed the need for a rulemaking proceeding and noted that expansion of access to customer information in the manner suggested by NCSEA should be handled with caution. DNCP noted that customers can be provided greater access than required by Rule R8-51, subject to conformance with DNCP's Code of Conduct, and also can access up to 18 months of historical usage data online or by telephone. In addition, with the customer's written consent, a customer may have his billing information released to a third party, or he may retrieve the information online and provide it to a third party. Further, DNCP stated that it cannot technically comply with NCSEA's suggestion of customer access to a "timely stream" of consumption data, since many of DNCP's North Carolina customers do not have automated metering technology.[11]

In their reply comments, DEC and DEP echoed some of the same concerns raised by DNCP regarding the importance of protecting customer information. DEC and DEP further stated that they have engaged in an ongoing dialogue with NCSEA and the Public Staff about customer data issues and "would not object to a separate rulemaking proceeding to explore customer data access if the Commission deems it advisable."[12]

SACE and the Sierra Club supported initiation of a rulemaking to examine the issue of access to customer data and to make appropriate changes.

In addition to the comments filed by intervenors, various parties, including trade associations, local governments, state agencies, nonprofits, and academic institutions, filed statements of position in support of NCSEA's request that the Commission open a separate rulemaking docket to review and modernize the rules governing access to customer energy usage data.

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[9] NCSEA second comments on March 8, 2013.

[10] NCSEA initial comments at 14, 18, 21, 26, 27.

[11] DNCP reply comments at 12.

[12] DEC and DEP reply comments at 12.

On August 23, 2013, the Commission issued an Order Requesting Additional Information and Declining to Initiate Rulemaking. In regard to NCSEA's contention that there is a current inadequacy of access to customer information, the Commission declined to make the requested finding on two grounds. First, the Commission noted that in its Order Declining to Adopt Federal Standards, issued on December 18, 2009, in Docket No. E-100, Sub 123, it had declined to adopt the federal standard for smart grid information set forth in Section 111(d)(19)(A)-(C) of the Public Utility Regulatory Policies Act (PURPA) because it found that the utilities were generally providing sufficient access to customer data, which the Commission expected to increase as smart grid technologies are implemented. The Commission also encouraged the utilities to investigate making real time pricing available to all customers and to update time-of-use (TOU) rates. The Commission also noted that in its May 30, 2013, Order Granting General Rate Increase in Docket No. E-2, Sub 1023, it had ordered DEP to complete a study regarding TOU rates and report the results to the Commission. Further, the Commission noted that Commission Rules R8-60 and 60.1 require IOUs to report certain information regarding access to customer information as they implement smart grid technology.

The Commission also disagreed with NCSEA's contention that there is an inadequacy of access to customer information based on Commission Rule R8-51, which the Commission noted is intended to provide customers with full access to all their usage data that is available. The Commission agreed with NCSEA that the availability of electronic and real time data from the IOUs should be clarified and ordered the IOUs to respond to questions regarding access to and availability of electronic and real time data.

As the Commission did not agree with NCSEA that there was an inadequacy of data or lack of customer access to such data, the Commission also declined to find that an inadequacy of data was an impediment to utilization of DSM/EE. Moreover, the Commission did not find that there was a clear linkage between access to customer data and utilization of DSM/EE, as there are a number of other variables that are barriers to greater implementation of EE.

In regard to NCSEA's request that the Commission initiate a rulemaking, the Commission found that such an investigation would be premature as there were insufficient details regarding consumption data that would be available in the future. The Commission indicated that it was inclined to wait until after the filing of the IOUs' smart grid reports on October 1, 2014. The Commission's August 23, 2013 Order also directed DEC, DEP and DNCP to file verified responses to questions listed on Attachment A of the Order by September 23, 2013.

On September 23, 2013, DEC, DEP and DNCP filed verified responses to the Commission's questions.

Public Hearings

Pursuant to G.S. 62-110.1(c), the Commission held two public hearings to take public witness testimony regarding the filed 2012 IRPs and 2012 REPS compliance plans. The first hearing was held on Monday, February 11, 2013, in Raleigh, North Carolina, where 43 public witnesses spoke. The second hearing was held on Thursday, February 28, 2013, in Charlotte, North Carolina, where 70 public witnesses spoke. The witnesses at both hearings discussed a wide range of issues, including the impact of coal-fired electricity generation, the threat of climate change, alternative models for establishing utility rate structures, the reasonableness of utility load growth forecasts, and the opportunities for increased uses of alternative resources such as wind, solar energy, and EE. During the course of this proceeding, the Commission also received over 2,500 letters or emails from customers, generally expressing concern over the utilities' continued reliance on fossil-fueled generation and support for increased use of renewable energy and EE.

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. The IOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable and should be approved.

2. The 2012 IRP biennial reports submitted by the IOUs, NCEMC, Piedmont, Rutherford, EnergyUnited and Haywood are reasonable and should be approved.

3 DEC and DEP complied with the Regulatory Conditions related to least-cost integrated resource planning imposed in the Commission's Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued June 29, 2012, in Docket Nos. E-2, Sub 998, and E-7, Sub 986 (Merger Order), approving the business combination of Duke Energy Corporation and Progress Energy, Inc., pursuant to G.S. 62-111(a).

4. DEC and DEP should continue to pursue least-cost integrated resource planning and file separate IRPs until otherwise required or allowed to modify this process by Commission order or until a combination of the utilities is approved by the Commission.

5. The IOUs and EMCs included a full discussion of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

6. The IOUs included in their IRPs a discussion of their market potential studies, including updates, for DSM and EE programs.

7. The IOUs and EMCs provided sufficient details of their investigations of the value of activating their current DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources.

8. The IOUs and EMCs adequately discussed the consumer education programs they currently provide to their customers, or propose to implement within the biennium.

9 The IOUs included in their IRPs a discussion of measures to inform all customers of their system summer peaks so that they might engage in voluntary demand response and peak shaving.

10. The IOUs and EMCs included in their IRPs a discussion regarding the impacts of smart grid deployment on their IRPs.

11. The IOUs provided an adequate assessment of alternative supply-side resources.

12. The IOUs should continue to include a full discussion of alternative supply-side resources in future IRPs to evaluate the potential impacts of these resources on their system.

13. The process used by the IOUs to evaluate resource options and selecting the least cost portfolio is reasonable.

14. DEP and DEC have adequately addressed the issues raised by Sierra Club, SACE, and NC WARN, et al., in this proceeding, including the proper evaluation of EE and DSM resources, least cost portfolio selection, peak demand and energy growth projections, baseload requirements, the cost of new nuclear generation, greenhouse gas emissions, and the potential economic viability of existing scrubbed coal units.

15. The Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.

16. DEC should continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

17. The 2012 REPS compliance plans submitted by the IOUs, GreenCo, EnergyUnited and Halifax are reasonable and should be approved.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

Load Forecasts

In its comments, the Public Staff stated that all of the utilities use accepted econometric and end-use analytical models to forecast their peak and energy needs. The Public Staff noted that, as with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future.

The Public Staff indicated that it reviewed the utilities' 15-year peak and energy forecasts (2013–2027). According to the Public Staff, the compound annual growth rates (CAGRs) for the forecasts of DEC, DEP, and DNCP were within the range of 0.9% to 1.7%, while the CAGRs for NCEMC and the four EMCs that filed IRPs were within the range of 0.9% to 1.9%. The Public Staff also briefly discussed the load reductions achieved by utilities' DSM and EE programs.

DEP

DEP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 0.9%, as compared to 1.6% in its 2011 IRP. Without consideration of the effects of its DSM and EE programs, DEP expects its summer peaks to grow at 1.2%. The average annual growth of its summer peak, which is considered its system peak, is 130 megawatts (MW) for the next 15 years, as compared to 201 MW in the 2011 IRP. DEP predicts that load reductions from its DSM programs will reduce its peak load by approximately 9% in 2027.

DEP's energy sales are predicted to grow at a CAGR of 1.0%, a 0.3% decrease from the projected growth rate in the 2011 IRP. DEP predicts that the megawatt-hour (MWh) reductions from its EE programs will reduce its energy sales by approximately 4% in 2027.

DEP's last annual system peak, 12,770 MW, occurred on Thursday, July 26, 2012, at the hour ending 5:00 p.m. At the time of the peak, DEP activated its EnergyWise Program and its Commercial, Industrial, and Government Demand Response Program, which reduced its peak load by 101 MW and 16 MW, respectively. DEP's 2011 IRP projected that it would have 803 MW available from its DSM programs to reduce its 2012 summer peak. DEP activated 117 MW of DSM in 2012.

DEC

DEC's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.7%, 0.1% lower than projected in the 2011 IRP. Prior to the implementation of its DSM and EE programs, DEC expects its summer peaks to grow at 2.0%. The average annual growth of its summer peak, which is considered its system peak, is 321 MW for the next 15 years, as compared to 351 MW from last year's IRP. DEC predicts that load reductions from its DSM programs will reduce its peak load by approximately 10% in 2027.

DEC's energy sales are expected to grow at a CAGR of 1.7%. This growth rate in energy sales is 0.1% less than predicted in the 2011 IRP. DEC predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 5% in 2027.

DEC's last annual system peak, 17,740 MW, occurred on Thursday, July 26, 2012, at the hour ending 5:00 p.m. DEC activated approximately 130 MW of DSM programs to lower the peak. DEC's 2011 IRP projected the availability of 838 MW from its DSM programs to reduce its 2012 summer peak.

DNCP

DNCP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.5%, which is a 0.1% increase from the projected growth rate in the 2011 IRP. The average annual growth of its summer peak, which is considered its system peak, is 285 MW for the next 15 years, as compared to 274 MW in the 2011 IRP. DNCP predicts that load reductions from its DSM programs will reduce its 2027 peak load by approximately 2%.

DNCP's energy sales are predicted to grow at an average annual rate of 1.6%. This projected growth rate in energy sales is the same rate as the growth rate in the 2011 IRP. DNCP predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 3% in 2027.

DNCP's last annual system peak, 16,787 MW, occurred on Friday, June 29, 2012, at the hour ending 5:00 p.m. At the time of the summer peak, DNCP called on its Distributed Generation Pilot[13] for a load reduction of 5 MW and its Air Conditioning Cycling Program for a reduction of 53 MW. DNCP's 2011 IRP projected the availability of 45 MW from its DSM programs to reduce its 2012 summer peak.

NCEMC

NCEMC's 15-year forecast predicts that its summer peaks will grow at an average annual rate of 1.4%, a decrease of 0.2% from the predicted growth rate in its 2011 IRP. The average annual growth of its summer peak, which is considered its system peak, is 48 MW.

NCEMC's last annual system peak, 3,121 MW, occurred on Wednesday, January 4, 2012, at the hour ending 7:00 a.m., which is comparable to 2011 when the system peaked at 2,982 MW on January 14 at 8:00 a.m. NCEMC's 2011 IRP projected that 52 MW would be available from its DSM programs.

[13] The Distributed Generation Pilot is a DSM program operating only in Dominion's Virginia jurisdiction.

NCEMC's energy sales are predicted to grow at an average annual rate of 1.4%, a decrease of 0.1% from the growth rate predicted in its 2011 IRP. NCEMC predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 1% in 2027.

EnergyUnited

EnergyUnited's 15-year forecast predicts that its system peak will grow at an average annual rate of 0.9%. Its energy sales are predicted to grow at an average annual rate of 0.9%. The average annual growth of the annual peak is 6 MW over the 15-year forecast. EnergyUnited's annual peak, 573 MW, occurred on Wednesday, January 4, 2012, at the hour ending 8:00 a.m. EnergyUnited activated its DSM programs and reduced the load by 15 MW at the time of the peak.

Haywood

Haywood's 15-year forecast predicts that its system peak will grow at an average annual rate of 1.8%. Its energy sales are predicted to grow at an average annual rate of 1.9%. The average annual growth of the annual peak is 2 MW over the 15-year period. Haywood's annual peak, 73 MW, occurred on Wednesday, January 4, 2012, at the hour ending 8:00 a.m. DEC, which has operational control of Haywood's DSM programs, did not activate the DSM programs at the time of Haywood's winter peak, but it did activate Haywood's DSM programs on two days during July 2012.

Piedmont

Piedmont's 15-year forecast predicts that its system peak will grow at an average annual rate of 1.7%. The average annual growth of its peak is 3 MW over the 15-year period. Piedmont's energy sales are predicted to grow at an average annual rate of 1.7%. Piedmont's annual peak, 125 MW, occurred on Sunday, July 8, 2012, at the hour ending 5:00 p.m. At the time of its peak, Piedmont did not activate its DSM programs.

Rutherford

Rutherford's 15-year forecast predicts that its system peak will grow at an average annual rate of 1.1%. Its energy sales are predicted to grow at an average annual rate of 1.0%. The average annual growth of Rutherford's system peak is 4 MW over the 15-year period. Rutherford's annual peak, 309 MW, occurred on Wednesday, January 4, 2012, at the hour ending 8:00 a.m. DEC, which has operational control of Rutherford's DSM programs, did not activate any of the DSM programs at the time of Rutherford's winter peak, but it did activate Rutherford's DSM programs on four days during June and July 2012.

Summary of Load Forecasts

The following table prepared by the Public Staff summarizes the growth rates for the IOUs' and EMCs' system peak and energy sales forecasts based on their 2012 IRP filings.

2013 - 2027 Growth Rates

(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	0.9%	1.2%	1.0%	130
DEC	1.7%	1.7%	1.7%	321
DNCP	1.5%	1.5%	1.6%	285
NCEMC	1.4%	1.4%	1.4%	48
EnergyUnited	1.2%	0.9%	0.9%	6
Haywood	1.8%	1.8%	1.9%	2
Piedmont	1.7%	1.7%	1.7%	3
Rutherford	1.1%	1.1%	1.0%	4

In general, the Public Staff concluded that the peak load and energy sales forecasts used by the utilities were reasonable for planning purposes. The Public Staff noted that among the IOUs both DEC's and DEP's forecasts predicted peak loads in excess of actual loads for the past five years and had peak load and energy sales forecast errors that were higher than those of DNCP. The Public Staff recommended that to the extent they have not already done so DEC and DEP should review their equations and other assumptions for possible refinement in order to reduce the possibility of overestimation bias in future load forecasts. In their reply comments, Sierra Club and SACE supported this recommendation. In their initial comments, NC WARN, et al., asserted that DEC and DEP have overestimated the growth in electric demand over the IRP planning horizon in order to justify the construction of new conventional power plants.

In their reply comments, DEC and DEP disputed the claims of NC WARN, et al., indicating that their IRPs present a robust and balanced portfolio over a range of sensitivities. DEC and DEP did not respond directly to NC WARN, et al.'s claim regarding overestimating growth in electric demand, except through incorporation by reference of their reply comments filed in IRP proceedings since 2006.

In its May 3, 2013, Order, the Commission stated that during the public hearings, as well as in comments regarding this proceeding that were mailed or e-mailed to the Commission, many citizens questioned whether the IRPs filed by DEC and DEP appropriately reflect the expected growth in demand for electricity, and directed DEC and DEP to provide verified answers to several questions related to load growth. In Request No. 3, the Commission asked questions regarding difference in projections in electric demand between DEC and DEP's service territory in North Carolina and forecasted electricity sales growth in Indiana and Ohio. In their June 10, 2013, verified responses, DEC and DEP indicated that based on the values used in their most recently filed IRPs in each jurisdiction, sales were projected to grow in all jurisdictions into the future. DEC and DEP further stated that variability in the rates was due to the following reasons:

- DEP, DEC, Duke Energy Ohio and Duke Energy Indiana have different local economies, population make up, retails sales environment, and weather patterns. The load forecasts for each area take into account these differences and they are reflected in the forecast results.
- The load forecasts also include the latest estimates of how sales are expected to respond to changes in key drivers such as economic indicators, population, end-use efficiencies, weather, and retail rates. Based on analysis, customer response to these drivers varies by state.
- Sales for some territories are expected to recover sooner while others are expected to recover later or more gradually, because each service area is in a slightly different state in the economic cycle/recovery as evidenced by trends in unemployment, income, and spending.
- The forecast impacts on load growth associated with incorporating utility sponsored EE programs or complying with a state commission's mandate vary by jurisdiction and the load forecasts show that include those impacts.[14]

In Requests No. 11 and 15, the Commission asked DEC and DEP to provide further justification for the significant volatility in retail sales load growth the utilities have experienced since 1996, including short periods of pronounced growth as well as declines, and to explain how they factored these recent experiences in load growth into their projected load growth in the planning period. The responses from both utilities pointed out the severe recession in 2008-2009 and the large structural decline in textiles

[14] DEC and DEP verified responses at 5.

having a significant impact on any growth estimates ending in 2011. The utilities stated that they relied on "long-term econometric models by class that relate kWh sales to factors such as weather, price of electricity, real income, as well as service area population projections. The coefficients from the long-term econometric models are then applied to the projections of the weather, economic, and population variables to arrive at the energy forecast."[15] Both utilities indicated that they believe the 1.4% (DEC) and 1.2% (DEP) forecasted load growth provided in their IRPs is reasonable for planning purposes.

In Request No. 12, the Commission asked DEC and DEP to explain a statement by then-President Jim Rogers quoted in the November 29, 2012, edition of the Charlotte Business Journal that the Company's load growth will be lower than projections in the economic models. The Company responded that Mr. Rogers was expressing his personal opinion and that the Company stands by the forecast included in its 2012 IRPs as an accurate forecast for the purpose of preparing the 2012 IRPs. These forecasts are updated annually and new forecasts will be reflected in the 2013 DEC and DEP IRPs."[16]

The Commission agrees with the Public Staff that all of the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs and recognizes the limitations of these models. Nonetheless, the Commission agrees with the Public Staff's recommendation that DEC and DEP continue to review their equations and other assumptions for possible refinement in order to reduce the possibility of overestimation bias in future load forecasts.

Reserve Margin Adequacy

For the planning period 2013 to 2027, the range of summer reserve margins reported by the electric utilities continues to be similar to those used in previous annual reports. For this time period, the reserve margins are:

Utility	Target Reserve Margin	Planned Reserve
DEP	14.5%	15% to 17%
DEC	15.5%	9.2% to 17.9%[17]
DNCP	11%	5.75% to 16.3%

[15] Id. at 14, 16.

[16] Id. at 15-16.

[17] DEC utilized a 20-year planning period, hence their planned reserve margins applies for the 2013-2032 period.

NCEMC indicates that all its purchases include reserves. Future purchases will also include reserves, or NCEMC will acquire reserves independently. The four independent EMCs have active contracts with DEC, DEP, and Southern Company, each requiring the EMCs to maintain reserves commensurate with the supplying electric utility. DEP's IRP indicates that DEP will meet its projected reserve margin targets for the planning period. The Public Staff stated that it considered the planned reserves of the electric power suppliers to be adequate.

DEC's IRP indicates that its reserve margins will drop below its target reserve margin percentages for short periods. DEC points out that significant solar generation is being added to its system. While this generation is not dispatchable, the generation primarily occurs during peak periods. Since the time of the filing of the 2012 IRPs, the interconnection of solar facilities has escalated for all electric suppliers in North Carolina due to the dramatic decrease in the cost of solar photovoltaic (PV) generation, the tax benefits available for renewable generation, and the requirements of the REPS in North Carolina. In addition, DEC's short short-term load growth appears to be lower than originally projected, and usage is lower, possibly due to economic conditions. Based on these factors and the relatively short time periods during which DEC's actual reserve margins fall below its target reserve margins, the Public Staff stated that it found DEC's planned reserves to be adequate. Nevertheless, the Public Staff recommended that DEC include the information required by Commission Rule R8-60(i)(3), which requires a specific explanation for instances when the projected reserve margin varies from the planning reserve margin by plus or minus 3%.

In its reply comments, DEC responded that the instances in which the projected reserve margin exceeded the target by more than 3% were due to "lumpiness" associated with new generation additions.[18] DEC indicated that the commencement of commercial operation of the Dan River Combined Cycle facility and Cliffside Unit 6 in the fall of 2012 caused an exceedance, but that the accelerated retirement of Buck Units 5-6 and Riverbend Units 4-7 in April 2013 reduced the planning reserve margin to be within 2% of the target reserve margin in 2014. DEC indicated that projected generation additions in 2019, 2022, and 2024 all cause similar exceedances, but that "there is a resource need in these years, that if not met, would require the reserve margin to dip below the target reserve margin."[19] DEC also noted that "while there are substantial increases in solar qualifying facility (QF) interconnection requests since the filing of the 2012 IRP, DEC feels that the solar projections utilized in the IRP adequately account for these additions." DEC stated that it is constantly monitoring the impact of these facilities to the system and will make adjustments to the plan going forward as necessary.[20]

[18] DEC and DEP reply comments at 4.

[19] *Id*.

[20] *Id*.

DNCP participates in the PJM market and, through the RPM auction, has obtained a commitment for additional capacity purchases above and beyond the existing identified firm purchases so as to ensure that its reserve margins meet the target of 11% reserves in 2013 and thereafter.

Based on its review of the annual plans, the Public Staff found that the reserves listed are adequate, and recommended that DEC, DEP, and DNCP maintain their proposed reserve margins as filed.

In their initial comments, Sierra Club and SACE stated that DEC's "treatment of demand response raises concerns that DEC may be planning for excessive reserves."[21] Sierra Club and SACE noted that in DEP's reserve margin study, demand response was treated as a resource option, which did not require its own reserve requirements, while in the DEC study, demand response was treated as a resource option requiring backstand reserves. Sierra Club and SACE also noted that:

> For purposes of calculating reserve requirements, system generation resources (and net transactions with other systems) should be compared to net internal demand. As defined by the North American Electric Reliability Corporation (NERC), net internal demand includes unrestricted non-coincident peak adjusted for energy efficiency, diversity, stand-by demand, non-member load, and demand response.[22]

Sierra Club and SACE noted that while DEC has previously stated that some of its programs are not dispatchable or controllable, therefore requiring backstand reserves, data from DEC indicated that it had been able to activate these programs on numerous occasions and achieve results consistent with, or even in excess of, expected reductions. Sierra Club and SACE noted that DEP's method of accounting for demand response appears to be more consistent with the NERC guidelines, and recommended that, with the exception of its PowerManager (air conditioner) program, DEC should evaluate demand response programs for purposes of calculating reserve requirements as adjustments to net internal demand, similar to the method utilized by DEP.

In its May 3, 2013, Order Requiring Verified Responses, the Commission asked DEC and DEP in Requests No. 13 and 16, respectively, to indicate the date on which and by what amount the highest portion of the utility's reserve margin was utilized to serve its system retail requirements. In their June 10, 2013 replies, DEC indicated for the period 2006 through 2011, its lowest actual reserve margin was 2.2% and occurred on August 9, 2007, while DEP indicated that for the period from 2006 through 2011, the lowest actual reserve margin was 7.1% and occurred on August 6, 2008. DEC and DEP indicated that this actual reserve margin represents the operating reserve margin without impacts of DSM and curtailment riders. DEC and DEP further explained that

[21] Sierra Club and SACE initial comments at 61.

[22] *Id*. at 63.

> the planning reserve margin is developed to account for abnormalities in weather, unit availability, and load forecast error, whereas actual reserve margin reflects the actual impacts of these events. Accordingly, the actual reserve margin is expected to be substantially lower than the target planning reserve margin at times.[23]

In Requests No. 14 and 17, the Commission asked DEC and DEP whether either utility had conducted an analysis or study of the potential of using neighboring wholesale resources, such as generation owned by TVA or generation located in PJM, to supply some portion of its reserve margin. In their verified responses, DEC and DEP indicated that their 2012 generation reserve margin studies, both of which were prepared by Astrape Consulting, considered and included the benefit of being interconnected to neighboring utilities such as TVA, Southern, PJM, and SCANA. DEC and DEP both indicated that their reserve margin requirements would have been substantially higher in their studies had these neighboring wholesale resources not been taken into account.[24]

The Commission agrees with the Sierra Club and SACE that in future reserve margin studies DEC should consider demand response programs that it is able to control or dispatch as adjustments to net internal demand, similar to DEP. Nonetheless, the Commission concludes that for the purposes of this proceeding, the reserve margins provided by the electric power suppliers are adequate, and that DEC, DEP, and DNCP should maintain their proposed reserve margins as filed.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The Regulatory Conditions in the Merger Order set forth commitments made by merging entities and their North Carolina public utility subsidiaries, DEC and PEC (now DEP), as a precondition of approval of the merger. As pointed out in the Public Staff's initial comments, a number of the conditions are relevant to this proceeding, but Regulatory Conditions 3.5 (Least Cost Integrated Resource Planning and Resource Adequacy), 3.6 (Priority of Service), and 4.1 are of particular significance. Regulatory Conditions 3.5 and 3.6 state as follows:

> 3.5 Least Cost Integrated Resource Planning and Resource Adequacy. DEC and PEC shall each retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight in accordance with North Carolina law. DEC and PEC shall determine the appropriate self-built or purchased power resources to be used to provide future

[23] DEC and DEP verified responses at 15, 17.

[24] DEC and DEP verified responses at 16, 18.

generating capacity and energy to their respective Retail Native Load Customers, including the siting considered appropriate for such resources, on the basis of the benefits and costs of such siting and resources to those Retail Native Load Customers.

3.6 Priority of Service.

(a) The planning and joint dispatch of DEC's system generation and Purchased Power Resources shall ensure that DEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA [Joint Dispatch Agreement]. DEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

(b) The planning and joint dispatch of PEC's system generation and Purchase Power Resources shall ensure that PEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. PEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

In addition, Regulatory Condition 4.1 provides that:

> DEC and PEC acknowledge that the Commission's approval of the merger and the transfer of dispatch control from PEC to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single BAA [Balancing Authority Area], control area or transmission system, (c) joint planning or joint development of generation or transmission, (d) DEC or PEC to construct generation or transmission facilities for the benefit of the other, (e) the transfer of any rights to generation or transmission facilities from DEC or PEC to the other, or (f) any equalization of DEC's and PEC's production costs or rates. If, at any time, DEC, PEC or any other Affiliate learns that any of the foregoing interpretations are being considered, in whatever forum, they shall promptly notify and

consult with the Commission and the Public Staff regarding appropriate action.

In its comments, the Public Staff stated that the 2012 IRPs filed by DEC and DEP appear to comply with these requirements. The Commission agrees and concludes that, pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP should continue to pursue least-cost integrated resource planning and file separate IRPs until required or allowed to do otherwise by Commission order or until a combination of the utilities is approved by the Commission.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-10

In the 2010 and 2011 IRP Orders, the Commission required the IOUs and the EMCs to include in their IRPs, among other things: (1) fuller discussions of their DSM/EE projections and programs, and (2) discussions of any year-to-year annual variance of 10% or more in their projected forecasts of DSM/EE resources. In its comments, the Public Staff indicated that the IOUs and EMCs have generally included these discussions in their IRPs, together with discussions of use of DSM/EE resources during system peak.

Over the planning horizon of the current IRP cycle, DEC projected capacity savings from DSM and EE that are generally 2% to 22% greater[25] than the projections in its 2011 IRP. Its energy savings in the 2012 IRP as compared to those in the 2011 IRP decrease in the early years by a combined 46%, but then increase by over 34%[26] by 2026 and beyond. DEC attributes these changes to the updating of its expectations for program performance, including new DSM and EE programs implemented in 2012 and the expectations identified in its 2012 market potential study. Calculations of projected participation and impacts were largely based on its most current five-year projection, with the five-year projection of impacts remaining constant after the fifth year through the end of the planning horizon. The figures do not include the impact of the grid modernization project discussed below.

Except for 2013, DEP's projected capacity savings from DSM and EE are generally 9% to 19.5% lower than the projections included in the 2011 IRP. However,

[25] Comparison of Line 17 of Table 8A in DEC's 2011 and 2012 IRPs.

[26] Year-by-year comparison of Table 4A in DEC's 2011 and 2012 IRPs. DEC changed the format of Table 4A in its 2012 IRP by adding a column showing the cumulative impacts of its EE programs. However, the Public Staff's calculations are based on a comparison of impacts added in 2011 versus those added in 2012, which do not include the cumulative impacts of the DSM/EE portfolio. The Public Staff believes it is more appropriate to reflect the cumulative impacts of DSM and EE programs as new measures are installed and old measures approach the end of their useful measure lives.

energy savings increase 4.2% to 19% over the same planning horizon.[27] DEP also developed its projections of DSM and EE based on the findings of its 2012 market potential study, and attributes the significant changes between the projections in its 2011 IRP and the 2012 IRP to the fact that its new market potential study was conducted by a different consultant who employed a different methodology that assumes a different relationship between MWh energy savings and peak MW demand savings. DEP cites this change in methodology as a driver for its forecasted increase for MWh energy savings and decrease for peak MW demand savings.

DNCP projected significantly lower MW and MWh savings from its portfolio of DSM and EE programs in its 2012 IRP than in its 2011 IRP, a 13% to 31% decrease in its forecast of capacity savings and a 23% to 72% decrease in energy savings over the planning horizon.[28] The larger percent decreases occur early in the planning horizon and appear to be due to regulatory changes in Virginia, as discussed more fully below. DNCP's practice of seeking approval of DSM and EE programs in Virginia before it seeks approval in North Carolina, and the cost caps imposed by the Virginia State Corporation Commission (VSCC), have hampered further development of its North Carolina DSM/EE portfolio. In its comments, the Public Staff stated that it is working with DNCP to determine whether it is cost-effective to offer the Commercial HVAC Upgrade and Commercial Lighting Programs on a North Carolina-only basis, and also to ascertain the proper jurisdictional allocation of the applicable costs. The Commission notes that this program received Commission approval on April 29, 2013, in Docket No. E-22, Sub 486.

In comparison with the capacity savings shown in its 2011 IRP, NCEMC's current projections[29] are generally greater in the earlier years of the planning horizon by as much as 36%, but show declines by as much as 12.7% in later years.[30] In response to a Public Staff data request, NCEMC indicated that the "Load Management and EE" data in Tables 1.3 and 1.4 of its IRP reflect EE program capacity savings at the time of the summer and winter coincident peaks. The Public Staff stated that it believes that these numbers actually reflect the DSM/EE program capacity available as a resource. However, the data also include customer-owned generation. The Public Staff stated in its comments that including both DSM/EE resources and customer-owned generation in Line 2 of Tables 1.3 and 1.4 makes it difficult to isolate only the DSM/EE program

[27] Changes in capacity and energy savings of DSM and EE programs are based on a comparison of tables on pages E-8 and E-9 of Appendix E of DEP's 2011 IRP and page E-11 of Appendix E of DEP's 2012 IRP.

[28] Calculated based on a comparison of Appendix 2H and 5E of DNCP's 2011 and 2012 IRPs

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[29] For the participating EMCs, NCEMC prepared the 2012 IRP, including load, capacity savings, and energy savings forecasts, while GreenCo prepared the 2012 REPS compliance plan, which included descriptions of the DSM and EE programs incorporated into the forecast tables of NCEMC's 2012 IRP.

[30] Percent changes for capacity are based on a year-to-year comparison of Line 2 in Table 1.3 of the 2011 and 2012 IRPs, which also includes customer-owned generation.

capacity. The Public Staff recommended that in future IRPs, NCEMC include separate line items for projected capacity from its DSM/EE portfolio and from customer-owned generation.

NCEMC's projections in its 2012 IRP of energy savings from its DSM/EE portfolio, as compared with the corresponding projections in its 2011 IRP, are 6% to 16% greater in the early years of the planning horizon, but decrease 3% to 13% in the later years of the planning horizon.[31] NCEMC indicated that these fluctuations result from changes in the EnergyStar Lighting and EnergyStar New Homes programs. The Public Staff indicated that its review of Table 6.2 in NCEMC's 2012 IRP also found decreases in the energy savings of the Commercial Energy Efficiency program, while the other DSM/EE programs maintain consistent or slightly higher savings across the planning horizon. In combination, these changes significantly decrease the energy savings from the portfolio of DSM/EE programs over the planning horizon, in comparison with the 2011 IRP.

The Public Staff's review of the DSM/EE portions of the 2012 IRPs filed by the independent EMCs -- Haywood, Piedmont, Rutherford, and EnergyUnited -- indicates that there is little difference from those filed in previous IRPs.

Each of the electric power suppliers also provided a listing and description of its current and proposed DSM/EE programs. DEC's portfolio of DSM/EE programs in its 2012 IRP includes the programs contained in its 2011 IRP. In addition, DEC added a Tune and Seal measure to its Residential Smart Saver Program, which was approved in Docket No. E-7, Sub 831; My Home Energy Report, which was approved in Docket No. E-7, Sub 1015; Residential Neighbor Low Income Program, which was approved in Docket No. E-7, Sub 1004; Appliance Recycling Program, which was approved in Docket No. E-7, Sub 1005; and the Call Option 200 measure in the Power Share Call Option program, Docket No. E-7, Sub 953. DEC indicated that it was considering proposing the My Energy Manager Program, a residential energy management solution.

DEP's portfolio of DSM/EE programs includes the programs identified in its 2011 IRP. Additional programs in DEP's 2012 IRP are the Residential New Construction Program, approved in Docket No. E-2, Sub 1021, and the Small Business Energy Saver Program, approved in Docket No. E-2, Sub 1022. DEP modified its Residential Lighting Program (renamed Energy Efficiency Lighting) in Docket No. E-2, Sub 950, to expand the measures offered and the availability of the program to non-residential customers. DEP also received approval to modify the Residential Home Energy Improvement Program (Docket No. E-2, Sub 936) and discontinue offering its Residential Home Advantage Program (Docket No. E-2, Sub 928), both due to cost-effectiveness issues. DEP also discontinued its Solar Water Heating Pilot Program, originally approved April 21, 2009, in Docket No. E-2, Sub 937, in 2012 because the program was not cost-effective. In addition to these program changes, DEP also included in its DSM/EE

[31] Percent changes for energy savings are calculated from data in Tables 6.2 of the 2011 and 2012 IRPs.

portfolio its Prepay EE program, which is currently approved as a pilot program only in South Carolina.

DNCP's portfolio includes the same DSM and EE programs discussed in the 2011 IRP, with several notable exceptions. Recently, DNCP was denied regulatory approval by the VSCC to expand its Residential Lighting program and implement its new Commercial Refrigeration program. The Commercial Lighting and HVAC programs were also terminated in Virginia and ultimately suspended in North Carolina due to cost-effectiveness issues. However, DNCP gained approval in Virginia for its Commercial Distributed Generation DSM program, Commercial Duct Testing and Sealing program, and Residential Bundle program.[32] DNCP indicated that it intends to file the Commercial Duct Testing and Sealing and Residential Bundle programs in North Carolina later this year.[33]

DNCP included a list of DSM and EE programs being considered for implementation. The list of programs is largely consistent with the list of proposed programs identified in the 2011 IRP, and includes a resubmittal to the VSCC of the Commercial HVAC and Lighting programs previously denied approval.

The Public Staff stated in its comments that it has worked collaboratively with DEC, DEP, DNCP, and other interested parties to encourage continuation of existing and implementation of new cost-effective DSM/EE programs. The Public Staff commented that the regulatory environment in Virginia continues to challenge the expansion of DNCP's portfolio in North Carolina, and that the cost recovery mechanisms for DEC, DEP, and DNCP will all be reviewed in 2013 and 2014. These subsequent changes to the mechanisms will impact the development of future DSM/EE programs for the IOUs.

The Commission finds that the IOUs and EMCs have adequately discussed their DSM/EE programs in their 2012 IRPs.

<u>Consumer Education Programs and Changes</u>

Commission Rule 8-60(i)(6)(iv) requires each utility to provide a comprehensive list of all consumer education programs it currently provides to its customers, or proposes to implement within the biennium. The utility is also required to provide a list of any educational program it has discontinued since its last biennial report and the reasons for discontinuance.

In its comments, the Public Staff noted that DEC did not specifically address this requirement in its IRP. However, the Public Staff noted that a number of DEC's

[32] The Residential Bundle program provides several HVAC-related measures to tune existing HVAC systems or upgrade to more efficient HVAC systems.

[33] DNCP filed these programs on August 20, 2013, in Docket No. E-22, Subs 496 and 500.

programs provide customer education. The Public Staff recommended that DEC address this requirement in its reply comments.

In its reply comments, DEC indicated that it has not discontinued any consumer education programs since the last IRP and currently has no plans to implement a new program. DEC provided a list and description of its current consumer education programs, which include Smart Energy Now, Non-Residential Assessments, Duke Energy Online Customer Education Resources, My Home Energy Report, Online Energy Audit, Energy Calculators, Energy Savings Tips, Home Energy House Call, and the K-12 Energy Efficiency Programs.

DEP's list of consumer education programs and changes to those programs remains consistent with previous IRPs. DEP's main consumer education initiative continues to be its Customized Home Energy Reports.

The lists of consumer education programs discussed by DNCP, NCEMC, Piedmont, EnergyUnited, and Haywood remain largely unchanged from the lists provided in their 2011 IRPs.

The Commission finds that the IOUs and EMCs have adequately addressed their consumer education programs in their 2012 IRPs.

Measures to Inform Customers of Forecasted Peaks and DSM Programs

In its October 30, 2012 Order in Docket No. E-100, Sub 133, which post-dated the filing of the 2012 IRPs, the Commission encouraged electric utilities to take appropriate measures to inform all customers of their system summer peaks so that they might engage in voluntary demand response and peak shaving. In its initial comments in this proceeding, the Public Staff stated that it expected the IOUs and EMCs to include a discussion of their plans to provide customers with this information in their 2013 IRPs.

In their reply comments, DEC and DEP noted that they proactively provide voluntary programs through its Demand Response Programs department to both residential and commercial customers. In addition, they stated that during periods when peak customer usage and/or system conditions forecast the need for additional conservation measures, DEC and DEP have communication plans in place to notify state government agencies, the general public, and company facilities and employees to conserve energy.

DNCP stated in its reply comments that it utilizes several methods to inform its customers of upcoming system peaks in both the summer and winter, including targeted news releases, routine news releases encouraging conservation, promotion of voluntary energy conservation through the internet and social media, and through its media relations staff highlighting energy conservation during peak periods on television and radio interviews.

The Commission finds that the IOUs have included an adequate discussion of their measures to inform all customers of their system summer peaks in their 2012 IRPs.

DSM/EE Market Potential Studies

The 2011 IRP Order required IOUs to include in their IRPs a discussion of their market potential studies, including updates, for DSM and EE programs.

DEC briefly discussed its market potential study for DSM/EE programs completed in late 2011 and indicated that the results were incorporated into Tables 4.A and 4.B of its 2012 IRP. The market potential study indicates that additional potential for DSM and EE in DEC's North Carolina jurisdiction exists, both through new programs and existing programs.

DEP's market potential study is incorporated into its tables of costs and savings identified in Appendix E of its IRP. As in DEC's case, the market potential study suggests that additional potential exists to achieve savings through new DSM/EE programs and expansion of existing programs.

Both DEC's and DEP's market potential studies are based on an economic potential calculated using an avoided cost of $0.07 per kWh. The Public Staff noted in its comments that DEC's consultant (who was also DEP's consultant) stated that its use of this rate was based on its judgment of a reasonable avoided cost considering the hourly shape of EE load impacts and consistency with DEC's avoided cost embedded in DSMore™ and used in its approved DSM/EE cost recovery mechanism. The Public Staff stated that it was concerned that this cost may be too high to properly assess the economic potential of DSM and EE in the Carolinas, particularly based on filings by the IOUs in the current avoided cost proceeding[34] that suggest that underlying avoided costs used to support the avoided cost rates proposed by the IOUs have decreased in the last two years. DEC's and DEP's market potential studies also included an assessment of economic potential using an alternative avoided cost of $0.05/kWh, resulting in an economic potential approximately 30% and 28% less than that calculated using the avoided cost rate of $0.07/kWh, respectively. Even at $0.05/kWh, DEC and DEP continue to see 8,222 and 6,493 million kWh of economic potential, respectively.

In their initial and reply comments, Sierra Club and SACE commented that relying on the PURPA avoided cost rates, as suggested by the Public Staff, would result in an underestimation of the economic potential of DSM and EE programs. Instead, Sierra Club and SACE propose that DEC and DEP utilize the "real levelized system benefit" to estimate the benefits of its DSM/EE programs and measures. Using this method, Sierra Club and SACE calculated the real levelized benefit of EE/DSM of

[34] Docket No. E-100, Sub 136 - 2012 Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities.

$0.097 per kWh for DEC and $0.113 per kWh for DEP for the planning period (2012-2031). To further support their assertion that avoided costs developed for PURPA purposes underestimate the system benefit of EE, Sierra Club and SACE provided data from three other utilities that have utilized this approach in their 2011 IRP processes, including TVA, PacifiCorp, and Avista Utilities. Based on this analysis, Sierra Club and SACE concluded that "using the PURPA avoided cost to measure the benefit of energy efficiency skews the cost-effective analysis and undervalues the economic potential of the resource."[35] Sierra Club and SACE recommended that DEC and DEP

- Update their potential studies to reflect the real levelized benefit of EE/DSM, which would result in higher economic potential, and should also update their achievable potential estimates for energy efficiency based on this higher estimate.
- Develop a method for estimating the benefit of energy efficiency that is consistent with the system benefit as demonstrated in their resource planning revenue models.
- Using the real levelized benefit of EE/DSM to estimate avoided cost, DEC and PEC should review their current and planned energy efficiency programs, update the programs' cost-effectiveness calculations, and enhance the programs with additional cost-effective measures to achieve greater customer savings.[36]

In addition, in their initial comments Sierra Club and SACE noted the large number of industrial and large commercial customers that choose to "opt-out" of utility sponsored EE programs and associated riders by implementing alternative DSM and EE measures at their own expense pursuant to G.S. 62-133.9(f) results in a significant lost resource opportunity. Sierra Club and SACE recommended several steps to address the impacts of the opt-out provision, including: (1) DEC and DEP pursuing opportunities to offer programs to these sectors; (2) the Commission initiating a process to verify that opt-out customers are actually implementing their own measures; (3) commercial and industrial customers provide the utilities with better information on their EE efforts, and (4) developing cooperative approaches to increasing the attractiveness of DSM and EE programs to industrial customers.[37]

The Commission notes that the effect of the opt-out provision was raised in DEC's annual DSM/EE cost recovery proceeding in Docket No. E-7, Sub 1031, and in DEC's proposal for approval of a new DSM/EE mechanism in Docket No. E-7, Sub 1032. In the proposed order filed by the Public Staff and DEC on July 25, 2013, in Sub 1031, DEC and the Public Staff proposed that the Commission authorize DEC, the Public Staff, and other interested parties to discuss a potential study or survey of

[35] Sierra Club and SACE reply comments at 2.

[36] Id. At 8.

[37] Sierra Club and SACE initial comments at 36-37.

opted-out customers within the collaborative process and to file an update of these discussions as part of its 2014 DSM/EE rider filing and any formal proposal regarding an opt-out study if deemed feasible and appropriate.

In Request Nos. 6, 7, and 8 of its Order Requiring Verified Responses, the Commission asked DEC and DEP to comment on several studies assessing the economic potential of energy efficiency in North Carolina and the Southeast.[38] In their June 10, 2013, reply comments, DEC and DEP generally indicated that the reports did not represent a significant departure from the economic potential analysis utilized by DEC and DEP in their forecasts, and that the following reasons explained some of the different findings amongst the studies: 1) uncertainty regarding customer adoption rates; 2) the time horizons considered; and 3) consideration of potential efficiency gains from building codes, appliance standards, and the natural replacement of end-of-life equipment, all of which are largely captured in the load forecasts of the utilities' IRPs rather than in the EE forecast.

DNCP did not update its 2009 market potential study as part of this proceeding. In its comments, the Public Staff stated that DNCP indicated that it intends to update its market potential study in 2013 and will incorporate the new market potential study in its 2013 IRP. In its March 5, 2013, reply comments, DNCP confirmed this statement.

Both GreenCo and EnergyUnited provided the Public Staff with copies of their respective updated market potential studies, which were completed in late 2012. Their estimates of future achievable potential are consistent with findings from several other evaluators conducting studies across the country. However, neither market potential study considered DSM in its evaluation. Both market potential studies were based on achieving an overall 40% market penetration, which the Public Staff found to be aggressive goals for EnergyUnited and GreenCo's individual member EMCs, given the current adoption and participation rates for EE programs for EnergyUnited and some of the EMCs. The recommendations contained in the market potential studies indicate that even with a 20% market penetration level, additional market potential for EE is available by adding new measures to existing programs, adopting new EE programs, and particularly for GreenCo, encouraging member EMCs to implement some of the existing portfolio programs that they do not currently offer. Neither market potential study expressly discusses the avoided costs used to develop the achievable potential. While a brief discussion of national EE resources in both market potential studies suggests that EE is available at $0.03 per lifetime kWh saved, the studies do not address the North Carolina achievable potential of cost effective EE.

[38] The three studies were the January 2013 report by the Georgia Institute for Technology, in cooperation with Oak Ridge National Laboratory entitled "Estimating the Energy-Efficiency Potential in the Eastern Interconnection", the 2006 GDS Associated report entitled "A Study of the Feasibility of Energy Efficiency as an Eligible Resource as Part of a Renewable Portfolio Standard for the State of North Carolina," and the March 2010 report by the American Council for an Energy Efficient Economy entitled "North Carolina's Energy Future: Electricity, Transportation, and Water Efficiency."

Piedmont, Haywood, EnergyUnited, and Rutherford did not include a discussion of a market potential study in their IRPs.

The Commission finds that the IOUs have included an adequate discussion of their market potential studies, including updates, for DSM and EE programs in their 2012 IRPs.

Use of DSM for Possible Fuel Savings

The 2011 IRP Order required each IOU and EMC to investigate the value of using DSM resources during times of high system load, when the marginal cost of fuel is generally at its highest, as a means of achieving lower fuel costs.

DEC discussed its use of DSM resources at various times to respond to both economic and reliability conditions on its system. DEC used some of these occasions to study the potential for fuel cost savings at times of high system costs, focusing on its Power Manager program. DEC's calculations indicate that potential fuel cost savings from this program were quite small and that the benefit of fuel savings is far outweighed by the avoided capacity costs. Through the use of both participant and non-participant surveys related to DSM usage, DEC concluded that customers could tolerate more frequent, but shorter-duration interruption events without causing participants to leave the DSM program. However, customer participation dropped significantly with longer duration DSM activations. DEC concluded that without careful management, using the DSM program to achieve fuel savings may result in customer attrition.

DEP performed a similar analysis on its Energy Wise Air Conditioning Load Control DSM program. Using actual historical Energy Wise events over the 2009 to 2011 period, DEP estimated that approximately $53,000 in fuel savings was achieved. However, the reduction in participation in Energy Wise would result in a net savings decrease of $49,000. DEP estimated that a net fuel savings of approximately $91,000 to $207,000 could be achieved over the next three years. Like DEC, DEP also evaluated customers' tolerance of more frequent DSM events, using survey and feedback data from current Energy Wise participants. DEP concluded that activating Energy Wise for economic purposes appeared to provide little or no additional value, when balanced with the risks associated with customer acceptance and retention.

DNCP did not expressly address the use of DSM to achieve fuel savings in its IRP. The Public Staff noted that in response to data requests, DNCP indicated that it had not undertaken any formal study of the effects of greater use of DSM during high system load conditions to achieve fuel savings, but acknowledged that it was reasonable to assume that fuel savings result from the use of demand response resources. DNCP included a brief discussion regarding the negative effect on participation in its Residential Air Conditioning Cycling DSM after activations over multiple days during the summer of 2011. As a result, DNCP observed some negative customer feedback, which resulted in customers leaving the program.

NCEMC and the three of the other EMCs indicated that their evaluation of possible fuel savings from the use of DSM resources suggested that at no time during the year were the marginal energy costs greater than the marginal costs associated with activating DSM resources. As a result, NCEMC indicated there were no potential fuel savings to be gained.

In its comments, the Public Staff noted that the potential benefits of using DSM for fuel savings were not as large as it had originally theorized. Based on the findings by DEC and DEP, and DNCP's first-hand experience with customer pushback, the Public Staff recommended that DNCP not be required to conduct a study of potential fuel savings from DSM. In its reply comments, DNCP agreed with the Public Staff's recommendation. The Public Staff stated that it did not believe it was necessary to continue to require discussion of this issue in future IRPs. In their reply comments, Sierra Club and SACE agreed with the Public Staff's recommendation as to current DSM programs, but stated that "utilities should have the opportunity to propose pilot programs or offer new technologies for using DSM to achieve economic fuel savings in the future."[39]

The Commission agrees with the Public Staff that the electric power suppliers should not be required to investigate this issue further. However, electric power suppliers are encouraged to continue to consider potential fuel savings benefits in their evaluations of cost-effective DSM programs in the future.

Smart Grid Impacts and Plans

On April 11, 2012, the Commission issued an Order in Docket No. E-100, Sub 126, amending Commission Rule R8-60 and adopting Rule R8-60.1. Amended Rule R8-60 requires electric power suppliers to file information in their IRPs regarding the impacts of smart grid. Beginning with the 2012 IRP, electric power suppliers were to include specific information regarding their smart grid impacts, including a description of the technologies already installed or planned to be installed in the next five years, a comparison of the gross MW and MWh impacts, and impacts to the North Carolina retail jurisdiction and customer classes. Beginning with the 2013 IRP, Rule R8-60.1 requires the electric power suppliers to include a "Smart Grid Technology Plan" with specific information regarding future investments in smart grid technologies.

DEC provided a general description of its "Grid Modernization" program, which involves improvements to its distribution system. DEC estimates that this effort will result in an additional 40 to 135 MW of reduced load over a 10-year period. As a result, DEC included 135 MW of smart grid impacts in the "DSM" column in Table 1.A of its IRP. DEC did not include any discussion of these impacts to the North Carolina retail jurisdiction or customer classes.

[39] Sierra Club and SACE reply comments at 8.

DEP provided a discussion of its Distribution System Demand Response (DSDR) program, which involves feeder conditioning, monitoring, and two-way communication capabilities. DEP completed installation of the DSDR program in 2012, and is continuing testing into the 2013 summer season. Ultimately, DEP estimates that DSDR will provide approximately 236 MW of DSM capacity. In its comments, the Public Staff stated that in response to a data request, DEP indicated that once DSDR is fully operational, DEP will incorporate the impacts now associated with its legacy voltage control demand response program and will discontinue reporting voltage control savings separately from DSDR. DEP segregated the impacts of DSDR for the North Carolina retail jurisdiction and customer classes in its IRP.

The Public Staff noted that DNCP did not specifically address its smart grid impacts or discuss plans for smart grid deployment in its 2012 IRP, but included in Chapters 3 and 7 of its 2012 IRP a brief discussion of its advanced metering infrastructure (AMI) and its dynamic pricing pilots that are under way in its Virginia service territory. The Public Staff recommended that DNCP include a discussion of its current smart grid impacts, including impacts by jurisdiction and customer classes, in its reply comments.

In its reply comments, DNCP provided additional details regarding the effectiveness and benefits of installing AMI or smart meters on homes and businesses in several demonstration areas across Virginia. The AMI demonstrations test the effectiveness of its Voltage Conservation program, remotely turning off and on electric service, and Dynamic Pricing Program, both of which are enabled by leveraging AMI as the foundational smart grid technology. DNCP estimated that the Voltage Conservation program saved an estimated 25,773 MWh in demonstration areas across Virginia in 2012, and that approximately 1,317 MWh should be applied to its North Carolina jurisdictional allocation. With regard to the Dynamic Pricing program, DNCP indicated that in response to data requests, it provided the Public Staff with an initial report that included information on customer enrollment and education, but "due to the nature of the rates, a full year of participation is required to analyze energy and demand savings."[40] DNCP stated that an initial measurement and verification (M&V) study will be provided as part of its 2013 annual report to be filed in August 2013, including information on energy and demand savings for the pilot period.

DNCP also noted in its reply comments that the current filing requirement for Smart Grid Technology Plans, July 1 of each odd-numbered year, does not coincide with the filing date of September 1 of each even-numbered year for IRPs, and that the inconsistency in the timing of these two requirements is not ideal for the utilities to develop and utilize the most current IRP analysis in their development of Smart Grid Technology Plans. DNCP therefore indicated that it would seek to coordinate with other utilities and the Public Staff regarding a delay, either of by motion or rule, of this requirement to October 1, 2014, and every two years thereafter, in order to synchronize the Smart Grid Technology Plan with the IRP filing requirements. In their reply

[40] DNCP reply comments at 8.

comments, DEC and DEP indicated that they support this recommendation. DNCP moved to amend Rule R8-60.1 on April 10, 2013, in Docket No. E-100, Sub 126, to change the filing date to October 1, 2014. The Commission granted the motion on May 6, 2013.

NCEMC provided a brief discussion of its grid modernization program, including deployment of a new demand response platform known as “Control Data Settlement System” (CDSS), which will support the AMI that several EMCs are implementing. The new CDSS will incorporate two-way communication capabilities and is intended to provide additional opportunities for DSM. NCEMC indicates that the first such program will be its customer-owned generation program. NCEMC also included information regarding the projected impacts of its smart grid initiatives by jurisdiction and customer classes.

Rutherford, Piedmont, Haywood, and EnergyUnited did not include a discussion of smart grid impacts or plans in their respective IRPs. The Public Staff recommended that Rutherford, Piedmont, Haywood, and EnergyUnited include a discussion of its smart grid plans in their reply comments. Rutherford and EnergyUnited filed reply comments addressing their smart grid plans.

The Commission finds that the discussions regarding the impacts of smart grid deployment are adequate for purposes of the 2012 IRPs.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-12

Assessment of Alternative Supply-Side Energy Resources

Commission Rule R8-60(i)(7) requires each utility to file its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. Each utility must also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or annual report.

For the currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility must provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility must also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance. For alternative supply-side energy resources evaluated but rejected, the utility must provide the following information for each resource considered: a description of the resource; the potential capacity and energy associated with the resource; and the reasons for the rejection of the resource. Each utility provided the information required by Commission Rule R8-60(i)(7).

Based on its planning assumptions, DEC projects that approximately 970 MW of renewable energy resources will be interconnected to its system by 2021, growing to approximately 1,665 MW by 2032. This is a significant increase from DEC's projections in 2011, which estimated approximately 686 MW in 2021 and 884 MW in 2031. Even more striking is the change by renewable energy resource type, which shows an increase in solar by an order of magnitude. In DEC's 2011 IRP, it forecast 51 MW of additional solar capacity by 2021 and 82 MW by 2031. In the current IRP, DEC forecasts 538 MW of new solar capacity by 2021 and 1004 MW by 2032. Further, DEC forecasts a significant decrease in the capacity additions from biomass, reducing its 2011 estimates of 295 MW in 2021 and 391 MW in 2031 to 108 MW in 2021 and 173 MW in 2032. The Public Staff noted that this change in DEC's forecast is consistent with the number of reports of proposed construction and applications for certificates of public convenience and necessity (CPCNs) filed by small power producers, particularly for proposed utility-scale solar PV facilities.

DEP did not provide as detailed a breakdown of its available or projected alternative supply-side energy resources, but did indicate that it forecasts purchasing 208 MW from renewable QFs in 2021 and 210 MW from renewable QFs in 2027. These numbers are an increase from DEP's 2011 IRP, in which it forecast 176 MW in 2021 and 39 MW in 2026.

DNCP projects that it will have 166 MW of renewable capacity in 2013, and that by 2027, it will add 248 MW of onshore wind resources and 34 MW of solar resources, convert three coal-fired facilities (totaling approximately 151 MW) to utilize biomass resources, and purchase additional biomass resources.

NCEMC listed three solar facilities totaling 6.8 MW AC and one landfill gas facility with a capacity of approximately 1 MW as currently operational or potential future alternative supply-side energy resources. It stated that it continues to be engaged in discussions with several developers of additional alternative supply-side resources.

In its comments, the Public Staff commended DEC on its analysis and discussion of alternative supply-side resource additions, as well as its clear delineation of new capacity additions by resource type. The Public Staff also recommended that in their future IRP filings, the other utilities provide additional details and discussion of projected alternative supply-side resources in a manner similar to that utilized by DEC.

In its reply comments, DNCP indicated that it believed its discussion of alternative supply-side resource additions met or exceeded the level of information and analysis provided by DEC, and therefore meets the Public Staff's recommendation.

Over the past few years, the landscape of alternative and distributed resource options has undergone considerable changes, as reflected in part by in the volume and scale of projects seeking CPCNs from the Commission. Greater analysis by the utilities on how these resources will integrate into their system, as well as any costs or benefits associated with the new resources, should be more fully considered in future IRPs. The

Commission agrees with the Public Staff that DEC's discussion of recent developments of alternative supply-side resources is a good starting point, and that utilities should continue to provide greater details of these developments in future IRP fillings.

In its amended initial comments filed on February 7, 2013, MAREC indicated that it had concerns about the treatment of renewables, specifically wind, by DEC and DEP in the IRPs, and that several policy reasons supported further consideration of wind energy by the IOUs, including long-term price certainty, in-state investment and economic development, and environmental benefits. MAREC further proposed that DEC and DEP conduct a "new RFP process that would solicit at least 100 MW of new wind energy capacity through a long-term contract(s) for energy and RECs, which would act as a hedge against price volatility and help towards meeting their present and future REPS requirements."[41]

In their initial and reply comments, Sierra Club and SACE agreed that DEC's IRP reflected a more robust evaluation of renewable energy options than DEP's, but stated that both were still flawed in that they only evaluated higher levels of renewable energy resources at the initial screening phase. Sierra Club and SACE recommended that DEC and DEP, similar to DNCP, evaluate one or more "high renewables" portfolios that incorporate renewable energy resources above minimum REPS compliance. Sierra Club and SACE also agreed with MAREC that wind energy offers several benefits, including "lower production costs (and zero fuel costs), a smaller environmental footprint, and a modular nature that matches load growth more closely than larger capacity additions. They also recommended that DEC and DEP "evaluate wind energy not only for REPS compliance, but as a system resource."[42]

The Commission agrees with MAREC that DEP and DEC should continue to assess alternative supply-side resources such as wind energy on an ongoing basis. However, the Commission declines to recommend that the utilities conduct an RFP that is limited to a single resource type unless the specific resource is required for REPS compliance. The Commission does, however, agree that in future IRPs DEC and DEP should more fully consider resource scenarios that envision larger amounts of renewable energy resources similar to DNCP's Renewable Plan in their least-cost integrated resource planning, and to the extent those scenarios are not selected, provide a discussion regarding the reasons.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-14

Evaluation of Resource Options

DEC, DEP, and DNCP provided information regarding their analysis and evaluation of resource options as required by Rule R8-60(i)(8). The IOUs indicated that

[41] MAREC amended initial comments at 9-10.

[42] Sierra Club and SACE reply comments at 12-13.

they use accepted production cost simulation models that identify the least cost mix of resources required to meet the future energy and capacity needs in an efficient and reliable manner at the least cost. These models have the ability to perform optimization analyses to select among competing resources that could be added in various combinations to satisfy the utility's future load requirements. They are designed to compare various generation portfolios to determine which has the lowest present value of revenue requirements (PVRR), while maintaining the target reserve margin, and is thus the least-cost portfolio.

The models incorporate forecasts of energy sales and peak load with planning assumptions on the operating characteristics of existing generating units (including, but not limited to net MW output, planned outages, forced outage rates, projected fuel prices, heat rates, start costs, emission costs, and variable operating and maintenance expenses) to calculate the projected dispatch cost of each generating unit. In order to arrive at a least cost plan, the models integrate assumptions regarding planned generation uprates and retirements, planned renewable energy generation, DSM and EE programs, environmental regulations, and the capital costs and operating characteristics for proposed traditional generation and alternative resources.

To consider the uncertainties, the utilities generally develop a base or preferred plan and alternative plans. These plans are analyzed under a variety of scenarios, including changes in projected loads, fuel prices, carbon dioxide (CO_2) emission credit prices, construction costs, and other sensitivities over the planning period, allowing the utility to choose the optimal plan that provides a balanced mix of traditional generation, renewable energy, DSM and EE to meet its baseload, intermediate, and peaking requirements.

In its comments, the Public Staff indicated that it reviewed the forecasts of fuel prices, existing generation characteristics, and the projected capital costs associated with new generation facilities used in the resource optimization models. The Public Staff indicated that based on its investigation, the projected operating and capital costs used in the production models**,** as well as the evaluation of resource options, were reasonable for purposes of this proceeding.

DEC's evaluation indicated that its preferred plan is the portfolio based on full ownership of two nuclear units going into service in 2022 and 2024, supplemented by combustion turbine (CT) and combined cycle (CC) natural gas-fired units. In its comments, the Public Staff noted that the all natural gas portfolio considered by DEC indicated a $10 million lower revenue requirement than the preferred nuclear portfolio. DEC maintained that the portfolios with nuclear remain competitive with the natural gas portfolio because the gas portfolio has more upside risk in fuel costs as identified in its sensitivity analysis. The Public Staff noted that DEC's contention that the nuclear portfolios are competitive is, in part, dependent on the assumption of a carbon constrained economy with the pricing of carbon under various cap and trade proposals or the enactment of clean energy legislation and DEC's desire to lower its carbon footprint. If carbon legislation is not enacted during the planning period, then the natural gas portfolio has a lower revenue requirement that is $3.8 billion lower than the nuclear portfolio and $3.5 billion lower than the regional nuclear portfolio.

In its comments, the Public Staff repeated the concerns regarding DEC's heavy reliance on nuclear generation it had previously raised in Docket No. E-7, Sub 819, and stated that "the benefit of additional nuclear generation from a fuel diversity perspective requires further evaluation. The economics of fuel diversity are difficult to quantify, especially during uncertain times. In addition, the potential risks associated with added construction costs and other uncertainties associated with nuclear power raise additional questions on the merits of DEC's preferred plan."[43]

In their initial comments and reply comments, the Sierra Club and SACE agreed with the Public Staff, finding that further development of new nuclear generation is subject to numerous risks and uncertainties "weighing strongly against over-reliance on nuclear generation in the DEC and [DEP] IRPs."[44] Sierra Club and SACE contrasted the approach taken by DEC and DEP with TVA, which "evaluated the environmental impacts of each alternative resource portfolio in terms of air emissions, water impacts, and waste disposal costs (coal ash and nuclear) in its 2011 IRP." Sierra Club and SACE asserted that adopting a broader approach, similar to that used by TVA, would allow DEC and DEP to be more explicit about how to balance various environmental risks. Sierra Club and SACE also recommended that the uncertain costs associated with the handling and storage of nuclear waste be both discussed and quantitatively assessed in the utilities' resource evaluations.

Sierra Club and SACE also noted in their initial comments the large number of coal-fired units that DEC and DEP have retired or are scheduled to retire in the next few years due to more stringent environmental regulations that apply to coal-fired units. Similar to the argument they made in the 2010 IRP proceeding, Sierra Club and SACE noted that these regulations also pose risks to the utilities' remaining facilities, including those that are already equipped with emissions controls such as scrubbers. Sierra Club and SACE recommended that the electric power suppliers include in their IRPs a more detailed discussion of regulatory risks faced by their coal fleet, including scrubbed plants, and impending regulations, including information on any investments required in further pollution control equipment or increased operating expenses.

DNCP evaluated the following four generation portfolios: Plan A or its Base Plan, which consists of all natural gas facilities; Plan B or its Fuel Diversity Plan, which consists of a combination of new natural gas-fired CTs, CCs, 248 MW of onshore wind, 10 MW of solar, and a new nuclear unit located at the North Anna site; Plan C or its Renewable Plan, which includes 100 MW of generic biomass, 248 MW of onshore wind, 1,600 MW of offshore wind, 20 MW of solar, and a combination of new natural gas-fired CTs and CCs; and Plan D or its Coal Plan, which includes the development of two

[43] Public Staff initial comments at 58-59.

[44] Sierra Club and SACE reply comments at 11.

695-MW coal-fired facilities equipped with carbon capture and sequestration technology, along with a combination of new natural gas-fired CTs and CCs. Following its evaluation, DNCP selected its Plan B, Fuel Diversity, as its preferred plan, despite the fact that Fuel Diversity Plan, under current planning assumptions, produces a higher cost than its Base Plan.

In its comments, the Public Staff noted that the concerns it expressed about the risks of relying on nuclear generation in DEC's plan also apply to DNCP. The Public Staff recommended that an electric utility that selects a preferred plan based on fuel diversity elaborate and provide additional support for its decision in its reply comments. The Pubic Staff also stated that:

> The electric utility industry has experienced significant changes in recent years and will continue to face a great deal of uncertainty. Each of the utilities discussed in its IRP the evolving commodity and technology trends that have resulted in substantial changes in the landscape. Hydraulic fracturing and the production of shale gas have pushed down natural gas prices and may transform the energy market for decades to come. The environmental and regulatory risks of shale gas production, however, remain uncertain. In addition, other changes, such as smart grid technologies and generation using renewable energy resources, present new challenges and opportunities as they continue to develop. Finally, regulations at both the state and federal levels have the potential to substantially change a utility's preferred resource mix. [45]

In addition, the Public Staff recommended that to the extent a utility selects a preferred plan based on circumstances that may exist beyond the planning period the utility should provide a justification for its reliance or consideration of those circumstances.

In its reply comments, DNCP noted that in addition to the expiration of the operating licenses for two of DNCP's four nuclear units during the study period (Surry Units 1 and 2), two additional units (North Anna Units 1 and 2) have license expirations that occur shortly after the study period. DNCP stated that '[n]uclear plant operating licenses have a known finite life, and recognition of the expiration of these major generating facilities' operating licenses is a reasonable consideration for DNCP to use in evaluating its choice of the preferred plan." DNCP acknowledged that its preferred plan under current planning assumptions is a higher cost than the base plan, but DNCP maintains that "the Preferred Plan will provide fuel-price stability for customers over the long-term by reducing an over-reliance on any one fuel source (namely, gas) and/or generation technology at the lowest reasonable cost." DNCP stated that its current customers are benefitting substantially from the Company's historic investments in nuclear, and that the Preferred Plan does include the addition of 3,550 MW of new natural gas capacity, as well as additional nuclear, wind, and solar resources. In

[45] Public Staff initial comments at 61-62.

response to the Public Staff's recommendation, DNCP indicated that it will develop additional support should it determine that a fuel diversity plan is the preferred plan over the Base Plan in its next North Carolina IRP.

The Commission recognizes 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. Fuel diversification, however, must be justified by an analysis of the benefits and costs of alternatives to achieve the same objectives. DEC's IRP indicates that the benefits of fuel diversity associated with a new nuclear facility may come at an additional cost of $3.5 billion to $3.8 billion under certain scenarios. Similarly, DNCP's reply comments and the Public Staff's comments recognize the higher cost associated with the benefits of fuel diversity with nuclear generation over the Company's Base Plan. The Commission agrees that the potential benefits of fuel diversification warrant further consideration, and concurs with the Public Staff that to the extent an IOU selects a preferred resource plan based on fuel diversity, the IOU should elaborate and provide additional support for how its decision complies with the statutory requirement of least-cost planning.

Concerns Raised by NC WARN, et al.

In their initial comments, NC WARN, et al., also expressed their opinions and concerns over several aspects of DEC and DEP's IRPs, including the following:

1) Expenditures on power plant construction that divert resources that could otherwise be utilized for weatherization and EE projects.
2) The much higher percentage of electricity that could be sourced from EE and renewable resources.
3) The IRPs do not reflect the economic potential for renewable energy resources and do not consider the potential of customer co-generation or combined heat and power (CHP).
4) The timing and escalating costs of nuclear plant construction pose significant economic risks to ratepayers, and the continued use of fossil fuels also raises significant environmental costs.

To support their positions, NC WARN, et al., attached two reports. The first, a Greenpeace report entitled, "Charting the Correction Course: A Clean Energy Pathway for Duke Energy," utilized some of the same modeling tools used by DEC and PEC, with different assumptions. Based on the Greenpeace Plan, NC WARN, et al., indicated that the overall costs of DEC and DEP's IRPs would decrease, while at the same time emissions would also be significantly reduced.

In their reply comments, DEC and DEP challenged the assumptions and methodology underlying the proposals submitted by NC WARN, et al., stating that the proposals are not realistic if "North Carolina wants to ensure reliable and affordable electricity are available to residential, commercial, and industrial customers, as the Companies are obligated to do."[46] Further, DEC and DEP asserted that their IRPs present a robust and balanced portfolio that will cost-effectively and reliably serve customer's short and long-term needs across a range of possible future scenarios.[47]

The Commission recognizes the efforts of Greenpeace and others to develop alternative models and IRPs that test the inputs and assumptions that go into utility resource planning, but concludes that the plans proposed by the utilities are reasonable for planning purposes.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-16

In its March 21, 2007, Order Granting Certificate of Public Convenience and Necessity with Conditions for Cliffside Unit 6, in Docket No. E-7, Sub 790, the Commission ordered DEC to retire, in addition to Cliffside Units 1-4, "older coal-fired generating units . . . on a MW-for-MW basis, considering the impact on the reliability of the entire system, to account for actual load reductions realized from [new EE and DSM] programs, up to the MW level added by" Cliffside Unit 6, i.e., 825 MW.[48] In the air permit issued by the North Carolina Department of Environment and Natural Resources, Division of Air Quality (DAQ) for Cliffside Unit 6, DAQ required DEC to implement a Greenhouse Gas Reduction Plan and to retire 800 MW of additional coal capacity without regard to achieving a commensurate level of MW savings from new EE and DSM programs. DEC's Greenhouse Gas Reduction Plan can be revised with DAQ's approval if the Commission determines that the scheduled retirement of any unit will have a material impact on the reliability of DEC's system.

In its 2011 and 2012 IRPs, DEC has included as Appendix J a Cliffside Unit 6 Carbon Neutrality Plan. This Plan incorporates actions required under the Greenhouse Gas Reduction Plan, as well as those required under DEC's additional obligations related to its Cliffside Unit 6 air permit to: (a) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Table J.1, (b) accommodate to the extent practicable the installation and operations of future carbon control technology at Cliffside Unit 6, and (c) take additional actions as necessary to make Cliffside Unit 6 carbon neutral by 2018. Table J.1 indicates that DEC plans to cumulatively retire 1,299 MW of coal capacity, not including Cliffside Units 1-4, by the end of 2015.[49] The projected retirements under the Cliffside Unit 6 Carbon Neutrality Plan would exceed the requirements of the Greenhouse Gas Reduction Plan by close to 70%. DEC states

[46] DEC and DEP reply comments at 11.

[47] Id.

[48] Order Granting Certificate of Public Convenience and Necessity with Conditions for Cliffside Unit 6, On March 21, 2007, in Docket No. E-7, Sub 790, at 140.

[49] On February 1, 2013, DEC announced the closure of Riverbend Units 4-7 and Buck Units 5 and 6 in April 2013. These units were listed in Table J.1 as closing by 2015.

that some older coal-fired units that are currently planned for retirement might instead be converted to natural gas. However, DEC will still greatly exceed the requirements of the Greenhouse Gas Reduction Plan, even with the possible coal-to-gas conversions.

Consistent with the 2011 IRP Order, the Public Staff recommended that the Commission approve the Cliffside Unit 6 Carbon Neutrality Plan as a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit, but state that it is not approving any individual specific activities or expenditures for any activities shown in the Plan. The Public Staff recommended that DEC continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

The Commission agrees with the Public Staff's recommendation. Therefore, the Commission concludes that the Cliffside Unit 6 Carbon Neutrality Plan is a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit; however, the Commission notes that this conclusion does not constitute approval of any individual specific activities or expenditures for any activities shown in the Plan.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 17

2012 REPS COMPLIANCE PLANS

All of the electric power suppliers in this proceeding indicated that they will achieve the general and solar requirements in G.S. 62-133.8(b), (c), and (d) for the planning period. They also indicated that their expenses to comply with the REPS in the planning period would not exceed the annual cost caps established in G.S. 62-133.8(h)(3) and (4).

In its REPS compliance plan, DEC stated that because of uncertainty with environmental permit requirements, it has reduced its reliance on biomass for future REPS compliance. DEC noted that it will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina to meet the in-state general requirement. However, the Commission notes that continuation of the federal production tax credit is uncertain, and repeal of the credit could limit future wind projects.[50]

DEP's REPS compliance plan indicated that it had implemented its Commercial and Residential SunSense programs to help it comply with the solar set-aside

[50] Section 407 of the American Taxpayer Relief Act of 2012 (P.L. 112-240, enacted on January 2, 2013) modified the eligibility criteria for the federal production tax credit for energy produced from qualifying renewable energy resources, including wind, by: (1) removing "placed in service" deadlines and replacing them with deadlines that use the beginning of construction as a basis for determining facility eligibility; and (2) extending the deadline for wind energy facilities by one year, from December 31, 2012, to December 31, 2013.

requirement of G.S. 62-133.8(d). The Residential SunSense program, which incentivizes solar PV systems up to 10 kW, was modified in February 2013 to reduce the up-front rebate paid to participants from $1 per watt to $0.50 per watt.

Halifax plans to meet the general REPS requirements for itself and the Town of Enfield through its EE programs, SEPA allocations, and out-of-state wind RECs. In its comments, the Public Staff noted that Halifax did not provide an M&V plan as required in R8-67(b)(1)(iii), and recommended that it file an M&V plan with its next REPS compliance plan.

In its reply comments filed on March 5, 2013, Halifax provided additional details regarding its means of verification for each of its programs, but stated that "given its numbers of members and limited staff any additional requirements for measurement and verification of these programs would not be a cost-effective use of Cooperative resources."[51] Halifax requested that the Commission accept the measures utilized by Halifax as sufficient for each of the EE programs. As the Commission discussed in its May 14, 2012, Order in Docket No. E-100, Sub 113, the Commission recognizes that electric power suppliers that have small customer bases also have low REPS cost caps, and that rigorous M&V protocols may be inappropriate in some cases, with the cost quickly dwarfing the economic value of the energy savings being measured. The Commission notes that Halifax submitted with its 2013 REPS compliance plan (Docket No. E-100, Sub 139) worksheets demonstrating how it calculated the energy savings for each of its EE programs. The Commission finds the level of data provided by Halifax in its 2013 submittal to be appropriate.

Swine and Poultry Waste Set-Asides in G.S. 62-133.8(e) and (f)

Several electric power suppliers indicated in their 2011 REPS compliance plans that they have had difficulty in obtaining RECs to comply with the swine and poultry waste set-asides in G.S. 62-133.8(e) and (f), which require them to meet a portion of their REPS obligations with energy derived from swine waste and poultry waste beginning in 2012. On May 16, 2012, the Commission issued an Order in Docket No. E-100, Sub 113, requiring the electric power suppliers to file an update on their efforts in meeting these compliance requirements. On June 1, 2012, the electric power suppliers filed a Joint Motion seeking to delay the swine and poultry waste set-asides as allowed in G.S. 62-133.8(i)(2). The joint movants claimed that they have had difficulty acquiring RECs to meet the swine and poultry waste set-asides because the technology for waste-to-energy facilities is still in its infancy and will need more time to reach maturity. A number of parties intervened in the docket, including three developers of waste-to-energy facilities, who indicated that they had had difficulty negotiating contracts with some of the electric power suppliers because of the lack of a standard contract form and lack of information on terms and conditions.

[51] Halifax reply comments at 2.

On November 29, 2012, the Commission issued an Order eliminating the 2012 swine waste set-aside requirement, delaying by one year the poultry waste set-aside requirement, requiring DEC and DEP to file triennial reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, and requiring internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities.

In its comments, the Public Staff stated that it believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides even with a one-year delay. The Public Staff concluded that while all electric power suppliers are on course to meet the general and solar REPS requirements for the planning period, they will have difficulty meeting the Commission's revised swine waste and poultry waste requirements in 2013 and possibly 2014, though they are actively seeking energy and RECs to meet these requirements. In addition, the Public Staff noted that the EMCs and municipalities have submitted REPS compliance plans that satisfy most or all of the filing requirements of Commission Rule R8-67(b). According to the Public Staff, the compliance plans also indicate that the electric power suppliers should be able to meet their REPS obligations during the planning period without nearing or exceeding their cost caps.

The Commission agrees that, with the exception of the swine and poultry waste set-asides, the 2012 REPS compliance plans submitted by the electric power suppliers indicate that they are generally well-positioned to comply with their future REPS obligations. The Commission therefore concludes that the 2012 REPS compliance plans filed in this proceeding by the electric power suppliers are satisfactory and should be approved. The Commission notes that on September 16, 2013, most of the electric power suppliers filed a joint motion requesting to be relieved of their 2013 swine and poultry waste obligations. On September 23, 2013, the Commission issued an Order in Docket No. E-100, Sub 113, scheduling an evidentiary hearing regarding the joint motion.

IT IS, THEREFORE, ORDERED as follows:

1. That this Order shall be adopted as part of the Commission's current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to G.S. 62-110.1(c).

2. That the IOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable and are hereby approved.

3. That the 2012 biennial IRP reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Rutherford, EnergyUnited, and Haywood are hereby approved.

4. That the 2012 REPS compliance plans filed in this proceeding by the IOUs, GreenCo, Halifax, and EnergyUnited are hereby approved.

5. That future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.

6. That future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.

7. That future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.

8. That each IOU shall continue to include a discussion of a variance of 10% or more in projected EE savings from one IRP report to the next.

9. That each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.

10. That all IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.

11. That, pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost integrated resource planning and file separate IRPs until otherwise required or allowed to do so by Commission order or until a combination of the utilities is approved by the Commission.

12. That DEC shall continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

13. That the Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is approved as a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit; provided, however, this approval does not constitute Commission approval of individual specific activities or expenditures for any activities shown in the Plan.

14. That in their future IRP filings, DEP and DNCP shall provide additional details and discussion of projected alternative supply side resources similar to the information provided by DEC.

15. That in future IRPs, DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.

16. That, to the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.

17. That, consistent with the Commission's May 7, 2013 Order in Docket No. M-100, Sub 135, the IOUs shall include with their 2014 IRP submittals verified testimony addressing natural gas issues, as detailed in the body of that Order.

ISSUED BY ORDER OF THE COMMISSION.

This the 14th day of October, 2013.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Chief Clerk

mr101413.01

Former Commissioners William T. Culpepper, III and Lucy T. Allen, and present Commissioners Don M. Bailey, Jerry C. Dockham, and James G. Patterson did not participate in this decision.