STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 128

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of Integrated Resource Planning in North Carolina - 2010	)))	ORDER APPROVING 2010 BIENNIAL INTEGRATED RESOURCE PLANS AND 2010 REPS COMPLIANCE PLANS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Monday, January 24, 2011, at 7 p.m.

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

APPEARANCES:

For Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.:

Len S. Anthony, General Counsel, 410 South Wilmington Street, Post Office Box 1551, Raleigh, North Carolina 27602-1551

For Duke Energy Carolinas, LLC:

Charles A. Castle, Senior Counsel, Duke Energy Corporation, 526 South Church Street, EC03T/Post Office Box 1006, Charlotte, North Carolina 28201-1006

For Duke and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power:

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

For North Carolina Electric Membership Corporation:

Robert Schwentker and Richard Feather, 3400 Sumner Boulevard, Raleigh, North Carolina 27616

For Southern Alliance for Clean Energy:

> Gudrun Thompson, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For North Carolina Sustainable Energy Association:

> Kurt Olson, 1111 Haynes Road, Suite 900, Raleigh, North Carolina 27604

For North Carolina Waste Awareness & Reduction Network:

> John D. Runkle, Post Office Box 3793, Chapel Hill, North Carolina 27515

For the Using and Consuming Public:

> Robert S. Gilliam, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

> Leonard G. Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the ratepayers consistent with 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.

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). G.S. 62-110.1 further requires the Commission to consider this analysis in acting upon any petition for construction. 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: (1) a report of the Commission's analysis and plan; (2) the progress to date in carrying out such plan; and (3) the program of the Commission for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in this analysis and plan.

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….

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' IRP. Commission Rule R8-60 requires that each of the investor-owned utilities, the North Carolina Electric Membership Corporation, and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources (hereinafter, collectively, the electric utilities) furnish the Commission with a biennial report in even-numbered years that 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 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance plan as part of its IRP report. Within 150 days after the filing of each electric utility's biennial report, and within 60 days after the filing of each electric utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the electric utilities' IRP 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 2010 biennial integrated resource plans (IRPs) were filed by the following investor-owned utilities (IOUs): Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas, LLC (Duke); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP); and the electric membership corporations (EMCs): North Carolina Electric Membership Corporation (NCEMC); Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Haywood EMC (Haywood), and EnergyUnited EMC (EU). In addition, REPS compliance plans were submitted by the IOUs, GreenCo Solutions, Inc. (GreenCo),[1] Halifax EMC (Halifax), and EU.

In addition to the Public Staff, the following parties have intervened in this docket: the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); the North Carolina Sustainable Energy Association (NCSEA); the Public Works Commission of the City of Fayetteville (Fayetteville); Nucor Steel-Hertford (Nucor); the North Carolina Waste Awareness & Reduction Network (NC WARN); the Southern Alliance for Clean Energy (SACE); and the Carolina Utility Customers Association, Inc. (CUCA). The intervention of the Attorney General is recognized pursuant to G.S. 62-20.

Procedural History

On August 20, 2010, Rutherford filed a letter indicating that it had a long-term power supply agreement with Duke, its load would be reported for filing purposes within Duke's IRP, its renewable energy requirements under the REPS would be provided by Duke, and its REPS requirements would be reflected in Duke's 2010 REPS compliance plan. Also on August 20, 2010, PEC moved to extend the filing date for its IRP to September 12, 2010. This motion was granted by the Commission on September 1, 2010. On August 27, 2010, EU filed its 2010 IRP and its 2010 REPS compliance plan. On August 31, 2010, Halifax filed for an extension of time to file its 2010 REPS compliance plan. The Commission by Order issued on September 14, 2010, granted Halifax an extension up to and including October 15, 2010. On August 31, 2010, Haywood filed its 2010 IRP. On September 1, 2010, Duke and DNCP filed their 2010 IRPs and REPS compliance plans; GreenCo filed a compliance plan on behalf of its members; and Piedmont, NCEMC, and Rutherford filed their 2010 IRPs. On September 13, 2010, PEC filed its 2010 IRP and REPS compliance plan. On October 15, 2010, Halifax filed its 2010 REPS compliance plan.

By Order dated December 3, 2010, the Commission scheduled a public hearing for January 24, 2011, on the filed IRPs and REPS compliance plans. On December 13, 2010, SACE requested an evidentiary hearing on issues to be identified by the Commission. On December 17, 2010, NC WARN made a filing in support of SACE's request for an evidentiary hearing. On December 28, 2010, PEC moved that the Commission delay ruling on SACE's request until SACE and NC WARN had identified elements of the electric utilities' IRPs with which they disagree and allow parties to respond to the identification of issues. On January 13, 2011, the Public Staff moved that the deadline for the filing of comments on IRPs be extended to February 10, 2011. The Commission granted this Motion on January 19, 2011.

[1] GreenCo filed a consolidated 2010 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 public hearing was held as scheduled on January 24, 2011. The public witnesses in attendance testified in support of energy efficiency (EE) and renewable energy technologies, in opposition to coal and nuclear generation, and against rate increases.

On February 9, 2011, DNCP filed an updated 2010 REPS compliance plan. On February 10, 2011, comments were filed by the Public Staff and SACE. On February 11, 2011, comments were filed by NC WARN. Both SACE and NC WARN requested that the Commission hold an evidentiary hearing on the IRPs of Duke and PEC.

On February 23, 2011 Duke moved that the deadline for filing reply comments be extended until March 1, 2011. The Commission granted the motion on February 24, 2011.

On March 1, 2011, reply comments were filed by Blue Ridge EMC (Blue Ridge), PEC, Duke, and DNCP addressing the comments of the Public Staff, SACE, and NC WARN. On March 3, 2011, Blue Ridge submitted a corrected version of its reply comments. On March 10, 2011, the Public Staff clarified two items in its February 10, 2011 comments.

On April 14, 2011, the Commission issued an Order Denying Request for Evidentiary Hearing. On April 29, 2011, NC WARN filed a Motion for Reconsideration of that order, to the limited extent of allowing parties to file proposed orders or briefs before the Commission issues its final order in this proceeding. On May 2, 2011, Duke filed a supplemental response to the Public Staff's initial comments. On May 5, 2011, the Commission issued an Order allowing parties to file proposed orders or briefs.

On June 6, 2011, the following parties submitted briefs or proposed orders: PEC, Duke, DNCP, NC WARN, and SACE. Also on June 6, 2011, NCSEA submitted comments. The Public Staff did not submit a brief or proposed order in this proceeding.

On June 14, 2011, Duke filed an Objection to NCSEA's Comments Filing. In Duke's objection, it requested that the Commission reject NCSEA's filing as grossly out of time. On June 17, 2011, NCSEA submitted a Reply to Duke's Objection to NCSEA's Comment Filing. According to NCSEA, its comments were firmly grounded in the record and, like a brief, consisted of contentions based on the record evidence. Upon review of these filings, the Presiding Commissioner concluded that NCSEA's comments should be treated as a brief. As such, NCSEA could not raise new issues in its filing because they should have been filed within the time allowed for comments on the utilities' IRPs. Therefore, only arguments asserted by NCSEA regarding issues previously raised in comments submitted by the Public Staff and the other intervenors were allowed and taken into consideration by the Commission in reaching its decision in this docket.

Based upon the foregoing, the information contained in the 2010 biennial IRPs, the 2010 REPS compliance plans, the comments and reply comments, and the Commission's entire record of 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 thus produced are reasonable for purposes of this proceeding and should be approved.

2. The IOUs' 2010 biennial IRP reports are reasonable and should be approved.

3. The IOUs' 2010 REPS compliance plans are reasonable and should be approved.

4. The 2010 biennial IRP reports and 2010 REPS compliance plans submitted by NCEMC, Piedmont, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved.

5. PEC and Duke have adequately addressed the issues raised by SACE and NC WARN in this proceeding including the proper evaluation of EE and demand-side management (DSM) resources, least cost portfolio selection, peak demand and energy growth projections, baseload requirements, the cost of new nuclear generation, greenhouse gas (GHG) emissions, and the potential economic viability of existing scrubbed coal units.

6. PEC has provided adequate information in this proceeding related to the planned retirements of its coal-fired generating units.

7. PEC and Duke have provided adequate information in this proceeding regarding their reserve margins, as required by Rule R8-60(i)(3).

8. Duke should file in the respective dockets of each affected DSM program and pilot a calculation showing the difference between the avoided cost capacity and energy benefits, as originally filed, and the avoided cost benefits recalculated using the correct DSMore model calculation methodology.

9. The loads of French Broad EMC (French Broad) and Blue Ridge are reflected in the IRPs filed by NCEMC and Duke, respectively, and French Broad and Blue Ridge are not required to file individual IRPs.

10. All EMCs should include a full discussion in future biennial IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

11. If Piedmont determines that its smart meter program is an EE program, it should file for Commission approval of the program pursuant to Rule R8-68.

12. In future biennial IRPs, EU should provide a more detailed description of the participation and savings related to specific DSM and EE programs, particularly those its proposes to use to meet its REPS obligations.

13. PEC and Duke should each prepare a comprehensive reserve margin requirements study and include these as part of their 2012 biennial IRP reports. PEC and Duke should keep the Public Staff updated as they develop the parameters of the studies.

14. Each IOU and EMC should investigate the value of activating 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. This issue should be addressed as a specific item in their 2012 biennial IRP reports.

15. Each electric utility should use appropriately updated DSM/EE market potential studies.

16. The current scenarios relating to carbon emissions, as provided in the IRPs, are responsive and appropriate for purposes of this proceeding.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 4

Peak and Energy Forecasts

In the Public Staff's comments, it stated that all of the electric utilities use accepted econometric and end-use analytical models to forecast their peak and energy needs. 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 has reviewed the electric utilities' 15-year peak and energy forecasts (2011–2025). The compound annual growth rates (CAGRs) for the forecasts of PEC, Duke, and DNCP are within the range of 1.2% to 1.8%. The CAGRs for NCEMC and the four independent EMCs that filed IRPs (EU, Haywood, Piedmont, and Rutherford) are within the range of 1.2% to 2.2%.

PEC

The Public Staff's one-year review of PEC's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 1% error.[2] The low forecast error rate was, in part, due to the system-wide average temperature of 96 degrees Fahrenheit, which was approximately equal to PEC's normal peak-day temperature. The Public Staff's five-year review of PEC's peak load and energy sales forecasting accuracy shows that the predictions in the 2005 IRP were reasonably accurate with less than a 5% forecast error.

The Public Staff believes that the economic, weather, and demographic assumptions that underlie PEC's peak and energy forecasts are reasonable and that PEC has employed accepted statistical and econometric forecasting practices. In conclusion, the Public Staff believes that PEC's peak load and energy sales forecasts are reasonable for planning purposes.

Duke

The Public Staff's one-year review of Duke's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 2% error. The system-wide average temperature was 93 degrees Fahrenheit, which was approximately one degree cooler than the normal peak-day temperature. The Public Staff's five-year review of Duke's energy sales forecasting accuracy shows that the predictions in Duke's 2005 IRP were reasonably accurate with less than a 5% forecast error. However, the forecast accuracy of Duke's peak loads reflected a 5.7% forecast error. The above-average forecast error for the five-year period results from the relatively low actual peak loads reported in 2009 and 2010, which were more than 8% below the predicted peak loads. These two forecast errors were mainly due to a reduction in new customers in 2010 and an even larger reduction in new customers in 2009. Duke's 2010 forecast more accurately reflects the current economic environment.

The Public Staff believes that the economic, weather, and demographic assumptions that underlie Duke's peak and energy forecasts are reasonable, and that Duke has employed accepted statistical and econometric forecasting practices. In conclusion, the Public Staff believes Duke's forecasts are reasonable for planning purposes.

DNCP

The Public Staff's one-year review of DNCP's peak load accuracy shows that the predictions in the 2009 IRP represent a forecast with less than a 1% error. The Public Staff's five-year review of DNCP's peak load and energy sales forecasting accuracy shows that the predictions in the 2005 IRP were reasonably accurate with less than a 5% forecast error.

[2] The Mean Absolute Error is used to calculate the forecast error.

The Public Staff believes that the economic, weather, and demographic assumptions that underlie DNCP's peak and energy forecasts are reasonable, and that DNCP has employed accepted statistical and econometric forecasting practices. In conclusion, the Public Staff believes that DNCP's peak load and energy sales forecasts are reasonable for planning purposes.

NCEMC

The Public Staff's analysis of NCEMC's peak load forecasting accuracy over the past five years indicates that the forecasts in its 2005 annual report were on average 247 MW lower than its actual system load, which equates to a 8% forecast error. Its energy sales forecast has been reasonably accurate with less than a 5% error rate. In response to the Commission's Order in Docket No. E-100, Sub 124, NCEMC reworked its load forecasting method by partnering with SAS Institute, Inc., to develop new state-of-the-art statistical models. The new peak demand models implemented by NCEMC are based on usage per customer and allow for the quantification of changes in peak demand among each of its member cooperatives that are attributable to changes in weather conditions and other factors. The Public Staff is cautiously optimistic that its concerns expressed in prior IRP dockets about the accuracy of NCEMC's forecasting methods will be resolved by this new forecasting process; however, it will still be necessary to review the forecasts for several years, contrasted with actual peak loads realized, before the impact of the changes in forecasting methodology can be fully assessed. The Public Staff believes that the current forecasts by NCEMC are reasonable for planning purposes.

EU

EU's 15-year forecast predicts that its winter peak, which is considered 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 1.2%. The average annual growth of the annual peak is 6 MW over the 15-year forecast. The Public Staff believes that the forecasts by EU are reasonable for planning purposes.

Haywood

Haywood's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 2.1%. Its energy sales are predicted to grow at an average annual rate of 2.0%. The average annual growth of the annual peak is 2 MW over the 15-year period. The Public Staff believes that the forecasts by Haywood are reasonable for planning purposes.

Piedmont

Piedmont's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 2.1%. The average annual growth of its summer peak is 3 MW over the 15-year period. Piedmont's energy sales are predicted to grow at an average annual rate of 2.1%. The Public Staff believes that the forecasts by Piedmont are reasonable for planning purposes.

Rutherford

Rutherford's 15-year forecast predicts that its winter peak, which is considered its system peak, will grow at an average annual rate of 1.4%. Its energy sales are predicted to grow at an average annual rate of 1.2%. The average annual growth of Rutherford's winter peak is 5 MW over the 15-year period. The Public Staff believes that the forecasts by Rutherford are reasonable for planning purposes.

Summary of Load Forecasts

The following table summarizes the growth rates for the electric utilities' system peaks and energy sales forecasts.

2011- 2025 Growth Rates
(After EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
PEC	1.6%	1.8%	1.2%	213
Duke	1.6%	1.6%	1.8%	322
DNCP	1.7%	1.8%	1.8%	342
NCEMC	1.8%	1.7%	1.7%	58
EnergyUnited	1.0%	0.9%	1.2%	6
Haywood	2.2%	2.1%	2.0%	2
Piedmont	2.1%	2.1%	2.1%	3
Rutherford	1.4%	1.4%	1.2%	5

Reserve Margins

PEC

A capacity margin is calculated by dividing reserves by the total supply resources, while a reserve margin is calculated by dividing reserves by the system firm load after the impact of DSM. PEC stated that a minimum capacity margin target range of approximately 11%-13% satisfies the one day in ten year Loss of Load Expectation (LOLE) criterion and provides an adequate level of reliability. PEC further stated that it considers 11% to be the minimum and acceptable capacity margin in the near term, but that 12-13% is appropriate to be used in the longer term due to forecast uncertainty. The projected capacity margins range from 12% to 20% over the planning period. PEC stated that these capacity margin values are the equivalent of 14% to 25% reserve margins, which were validated by the Public Staff. This implies a reserve margin target of 14% to 15% over the long term planning period. As shown in PEC's IRP, projected reserve margins exceed this targeted level significantly during the planning period and particularly during the 2011 to 2014 period. While PEC's plan details the addition of 635 MW of generation (Richmond County) in 2011 and 920 MW of generation (Wayne County) in 2013, it does not provide for a corresponding rate of retirement of other facilities. PEC noted that additional resources cannot be brought online in the exact amount needed to match load growth.

Duke

Duke stated that its own historical experience has shown that a 17% target planning reserve margin is sufficient and necessary to provide reliable power supplies for its North and South Carolina service areas. Duke also stated that from July 2005 through July 2009, generating reserves never dropped below 450 MW, but noted that there are increased risks associated with reserve margins, which include (1) increasing age of units, (2) inclusion of a significant amount of renewable energy (which is generally less available than traditional supply side resources), (3) uncertainty related to increases in the Company's EE and DSM programs, (4) longer lead times for constructing base load units, (5) increasing environmental pressures, and (6) increases in derates of units due to hot weather and drought.

DNCP

PJM conducts an annual reliability assessment to determine an adequate level of capacity in its footprint to meet the target level of reliability measured with a LOLE that is equivalent to one day of outage in ten years. PJM's 2009 assessment recommended using a reserve margin of 15.3% for the entire PJM footprint. DNCP uses the PJM reserve margin guidelines in conjunction with its own load forecast to determine its long-term need for capacity. The reserve margins for the first three years of the planning period are 16.1% (2011), 16.7% (2012), and 13% (2013). Because DNCP is only obligated to maintain a reserve margin for its portion of the PJM coincidental peak load, it used a coincidence factor of 96.3% to derive an effective reserve margin of 11% for 2014 through 2025.

DSM and EE

The Public Staff's review of the DSM/EE portions of the 2010 IRPs indicates that there is little difference from those filed in 2009. Duke, DNCP, NCEMC, and the independent EMCs, Haywood, Piedmont, Rutherford, and EU, generally forecast fewer DSM/EE resources (in terms of MW and megawatt-hours (MWh)) over the planning horizon. PEC indicated a small increase in its forecast of DSM resources. All of the electric utilities rely almost exclusively on the portfolio of DSM/EE programs they have designed and adopted over the last couple of years to meet their forecasted DSM/EE resources over the planning horizon, with only a few programs recently implemented or still under consideration.

Evaluation of Resource Options

PEC, Duke, and DNCP provided information describing their analysis and evaluation of resource options as required by Rule R8-60(i)(8). The IOUs use accepted production cost simulation models that have the ability to perform optimization analysis to select between different competing resource portfolios that potentially could be added in various combinations to satisfy the utility's future load requirements. The objective of these models is an identification of the least cost combination of resources as determined by an evaluation of the present value of revenue requirements for the various portfolios, while maintaining the target reserve margin. In addition to the review of the IOUs' load forecasts, future DSM and EE programs, and renewable resources, the Public Staff also reviewed forecasts of fuel prices, existing generation characteristics, and the projected capital costs associated with new generation facilities used in the resource optimization models. The investigation by the Public Staff indicates that the projected operating and capital costs used in the production models and the evaluation of resource options were conducted in a reasonable manner for purposes of this proceeding.

REPS Compliance Plan Review

G.S. 62-133.8 requires all electric power suppliers to provide specified percentages of their retail sales using renewable energy resources or reduced energy consumption through implementation of EE measures. Commission Rule R8-67(b) requires electric power suppliers to file a plan on or before September 1 of each year explaining how they will meet the requirements of G.S. 62-133.8(b), (c), (d), (e), and (f). The plans must cover the current year and the next two calendar years, or in this case 2010, 2011, and 2012.

Duke, PEC, and DNCP provided an assessment of alternative supply-side energy resources as part of their REPS compliance plans. All EMCs in North Carolina also provided plans.

The Public Staff noted that the electric power suppliers have had some difficulty obtaining sufficient resources from swine waste and poultry waste to meet the requirements of G.S. 62-133.8(e) and (f). The filings regarding the efforts of the electric power suppliers to meet these requirements are in Docket No. E-100, Sub 113.

Conclusions

Based upon the foregoing, the Commission finds 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 thus produced are reasonable for purposes of this proceeding and should be approved. The 2010 biennial IRP reports and 2010 REPS compliance plans submitted by the IOUs are reasonable and should be approved.

The Commission also finds that the 2010 biennial IRP reports and 2010 REPS compliance plans submitted by NCEMC, Piedmont, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Least Cost Resource Portfolio Selection

In its comments, SACE stated that Duke modeled several resource portfolios in its IRP analysis. Some of these portfolios used a "High Energy Efficiency" or "High DSM" case, which includes the full target impacts of the save-a-watt bundle of programs for the first five years and then increases the load impacts at 1% of retail sales each subsequent year until the load impacts reach the economic potential identified by Duke's 2007 market potential study, i.e., a 13% decrease in retail sales. Duke did not select a portfolio with the High DSM case, however, despite the fact that the portfolios incorporating Duke's High DSM case cost less, have lower risk, and appear to result in lower average electricity rates than does the optimal plan. As a result, Duke's plan does not result in the least cost mix of resources.

SACE argued that, in contrast to Duke's failure to select an identified resource portfolio with a High EE case, PEC failed to even model a high efficiency case. In its IRP, PEC identifies three alternative resource plans that it considered for scenario analysis. However, PEC did not identify any scenario that included a portfolio with additional investments in EE (or renewable resources). Rather, these three alternative plans differed only in terms of the amount of gas-fired and nuclear capacity contained in each and in the timing for new additions of units with these technologies. SACE maintained that PEC's failure to model different levels of EE reveals a critical flaw in the Company's analysis. PEC did not conduct a similar sensitivity analysis even though the Commission's 2010 order called for "full and robust analyses and sensitivities."

In its reply comments, Duke stated that, as to the substantive aspects of Duke's IRP, SACE initially criticized the Company's portfolio analysis for not prioritizing its High DSM case in all of its portfolios. It noted that SACE alleged that the High DSM case, when applied to all of the Company's potential portfolios, is lower cost to customers, lower risk to customers, and will result in lower rates to customers than Duke's Optimal Plan, which is its selected portfolio of 2 Nuclear Units (2021/2023) and incorporates the Company's Base Case. SACE also included confidential Attachment 1 to demonstrate the comparison of certain High DSM case portfolios to the Optimal Plan portfolio on a net present value basis. Duke submitted that it is notable that SACE did not include the cost comparison information for the High DSM case as applied to the 2 Nuclear Units (2021/2023) timeframe in Attachment 1. Duke argued that SACE's comparison of the Company's High DSM sensitivity cases to its Base Case portfolios is misleading and presents an "apples to oranges" comparison. Duke argued further that, SACE's analysis disingenuously fails to acknowledge that the Company's 2 Nuclear Units (2021/2023) timeframe is the most cost-effective portfolio under the High DSM sensitivity.

Duke explained that it is unreasonable to compare the Company's model portfolios that incorporate Base Case impacts for EE and DSM with those portfolios that incorporate High DSM impacts. SACE's analysis is fundamentally flawed in that its analysis compares model portfolios with different load profiles and is useless for the purpose of making any meaningful comparisons for resource planning purposes. This rings true for comparisons of Clean Energy portfolios, High Fuel Cost portfolios, and any other sensitivity portfolios to Base Case portfolios. According to Duke, the basic fact underlying this assertion is that each of the model portfolios includes the same load, and the production simulation model will dispatch the model to meet that load with the selected resource mix. When sensitivities are applied to a certain aspect of the model portfolios, such as to EE and DSM impacts, fuel costs or load variations, it must be applied to each model portfolio so that the selected aspect of each portfolio will be impacted similarly and the production simulation model will run each portfolio under the same constraints.

Duke maintained that SACE conveniently failed to address that when Duke's model portfolios are properly compared to each other, such that each portfolio includes the High DSM sensitivity impacts, the portfolio with 2 Nuclear Units (2021/2023) is the least cost to customers on a net present value basis. SACE's Attachment 1 to its comments includes all of the other evaluated portfolios with the High DSM sensitivity except the 2 Nuclear Units (2021/2023). However, one need only look to Table A2 of the 2010 IRP to discover that the 2 Nuclear Units (2021/2023) is $1.6 billion lower in cost on a net present value basis than the Natural Gas portfolio under the High DSM sensitivity. Applying that information to the chart set forth in Attachment 1, which includes the Natural Gas portfolio, clearly demonstrates the cost-effectiveness of the 2 Nuclear Units (2021/2023) portfolio as compared to the other portfolios under the High DSM sensitivity. Duke concluded that, even under SACE's misleading analysis, one can still objectively understand that the selected portfolio within Duke's 2010 IRP supports the development of a clean, reliable and cost-effective resource plan to meet its customer's need over the planning horizon.

According to PEC in its proposed order, its comprehensive analysis of achievable energy efficiency potential was described in the rebuttal testimony of PEC witness Chris Edge in Docket No. E-100, Sub 124. He stated that PEC contracted with ICF International, an industry leader in the design, implementation, market assessment and evaluation of DSM and EE programs, to perform a comprehensive analysis of the cost-effective, achievable potential across PEC's service territory. Mr. Edge testified that the ICF study considered the PEC-specific factors that impact potential savings from utility administered DSM and EE programs including: demographic and customer composition; PEC electric rates and avoided costs; known regulatory factors (i.e., the significant effect of customer opt-out provisions); and other assumptions specific to PEC's service territory. Mr. Edge explained that the study was intended to identify the approximate amount of cost-effective savings that can realistically be achieved through utility DSM and EE programs within the PEC service area over an extended period of time (and under a stated set of assumptions). He further explained that it serves as the foundation for identifying general areas and programs that might warrant consideration in PEC's DSM and EE portfolio. PEC argued that the DSM and EE potential a utility should incorporate into its least cost resource plan should be based upon a specific set of conditions that are unique to the utility's service territory to facilitate the most accurate comparisons with alternative solutions and that the methodology for deriving demand-side reductions for resource planning purposes should be based on a detailed, investment grade analysis of achievable, cost-effective options, versus a generic, hypothetical comparative analysis.

Evaluation of EE

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

SACE argued in its comments that, despite these benefits, Duke and PEC significantly underestimate the potential EE savings in their IRPs. The utilities failed to consider efficiency resources on an equivalent basis as supply-side resources, and therefore, their IRPs do not result in the least-cost mix of resource options. Together, PEC and Duke forecast cumulative energy savings of 5.2 percent of retail sales over the next fifteen years.

SACE stated that Duke limits its program potential to the economic potential identified by its 2007 market potential study. Duke witness Richard Stevie testified in the proceeding on the 2008 and 2009 IRPs, however, that this study is out of date and that Duke is continuing to look at additional programs that were not analyzed in the potential study. PEC limits its program potential to the cost-effective, realistically achievable potential in its updated potential study. While the scope of PEC's updated study does appear to be broader than the earlier version, it appears to suffer from the same fundamental shortcomings as the earlier study. For example:

- PEC's potential study mentions that the findings were benchmarked against other utilities, but such benchmarking, if it has been done, has not been disclosed.

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

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

- Energy savings practices, measures and entire sectors remain excluded from the scope of study.

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

Further, SACE argued that PEC effectively assumes no further technological progress or development of new energy-saving practices. Duke is more confident about advances in efficiency, although this confidence is not fully reflected in its long-term resource plans.

SACE alleged that PEC and Duke primarily evaluate renewable energy resources in the context of minimum compliance with the REPS. Renewable energy potential is barely varied among the strategies considered in the 2010 resource plans proposed by Duke and PEC. One exception to this limited perspective is that both utility plans discuss offshore wind development, which is likely to require more than a decade to develop. SACE noted that North Carolina's utilities are prudently evaluating this resource in order to determine the appropriate development path in light of its resource characteristics and forecast system resource needs.

Additionally, SACE maintained that Duke and PEC should conduct an analysis of the potential ancillary benefits or costs of integrating significant levels of on-system renewable energy resources, including:

- The potential benefits regarding grid stability;

- The potential efficiency gains in transmission and distribution associated with higher levels of distributed generation; and

- The reduced costs associated with greenhouse gas and air pollutant mitigation.

SACE stated that Duke and PEC assume that the benefit of renewable energy resources is limited to about 5 - 7 cents per kWh (avoided costs), which seems to be an underestimate. Moreover, these utilities spend about twice this amount to build and operate baseload, intermediate or peak power plants.

According to NC WARN, EE will play a significant role in North Carolina's energy future. In its April 29, 2010 presentation to the Energy Policy Council (EPC), the American Council for an Energy-Efficient Economy (ACEEE) presented an EE market potential study that demonstrated that an annual electricity savings of 1.2 - 1.6% is achievable over the next decade. Energy savings in the 24 - 32% range were shown to be achievable in North Carolina by 2025. Several other studies that have been presented to the Commission in recent years have shown similar potential savings. Given these savings, it is apparent from the IRPs that Duke and PEC incorporated into their IRPs only the minimal amount of EE required under the REPS, rather than what was practical. Last year NC WARN argued that the IRPs do not reflect customers who would adopt the EE measure regardless of any utility-sponsored EE program.

In its reply comments, PEC argued that NC WARN frequently comments on energy savings when discussing EE, without any real recognition of peak demand impact, implying that a 1% energy savings translates to 1% demand savings. This is a significantly flawed assumption. For example, NC WARN claims significant energy savings are realized through the replacement of incandescent light bulbs with compact fluorescents. While true that such actions produce energy savings, they have a negligible impact on summer peak demand which occurs late in the afternoon when lighting usage is insignificant.

PEC noted that SACE argued that PEC's long-term EE provisions lag significantly behind the "typical leading utility." SACE suggests that PEC should modify its IRP EE forecasts based on the arbitrary, aspirational goals of other utilities. In fact, SACE attempted to provide a comparative analysis of PEC and Duke with that of a generic "leading" utility. PEC offered that, as this is a fictional utility, SACE is unable to provide details as to where the utility is located, the composition of its customer base and its end-use load, the utility's rates, its avoided costs, etc. (all of which play a huge role in determining what DSM and EE programs it can cost-effectively offer). SACE then somehow determined the EE potential of this generic utility without any economic, technical, or market analysis. PEC then stated that, without any such supporting information, SACE concluded that PEC has significantly underestimated the potential EE savings in its IRPs and that "… Duke and PEC lag significantly behind the typical leading utility."

PEC noted that SACE also alleged that neither Duke nor PEC is using a comprehensive EE potential study in its IRP process. Regarding PEC, SACE stated: "PEC limits its program potential to the cost-effective, realistically achievable potential." PEC responded that it should only offer cost-effective, achievable DSM and EE programs. DSM and EE account for over 1,700 MW of load reduction in PEC's IRP. These projected impacts play a substantial role in PEC's ability to meet the future reliability needs of its customers. They must be real and achievable or the reliability of PEC's system will be impaired. Cost-effective, realistically achievable potential is the most prudent standard for resource planning purposes, versus a hypothetical potential derived from speculative, unsupported assumptions.

Duke argued that its projections relating to EE savings are not tied in any way to its REPS obligations. At present, the Company is statutorily limited to meeting up to 25% of its general REPS obligations under G.S. 62-133.8(b)(2)c through EE savings.[5]

[5] In 2021, when the REPS obligation increases to 12.5%, this limitation on the use of EE savings increases to 40%.

The Company's portfolio of programs are projected to achieve significantly more than 25% of the Company's general REPS requirements on an annual basis through the term of its 2010 REPS compliance plan. Under its REPS compliance plan, Duke stated that it intends to utilize EE to the fullest extent possible, accounting for 25% of the compliance requirement beginning in 2012, but this is not a limiting factor on the amount of EE the Company will be actively promoting. The Company's modified save-a-watt model, approved in the Commission's Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues issued February 9, 2010, in Docket No. E-7, Sub 831, incentivizes it to attempt to achieve all cost-effective EE over the course of the pilot in order to achieve its stated savings targets.

Duke further added that, during the same meeting in which ACEEE presented its potential study to the EPC, Duke and PEC made a joint presentation which identified specific significant deficiencies in the ACEEE study. These deficiencies include:

- A lack of any adjustment for large customer statutory opt-out of utility EE and demand-side management programs, as permitted under G.S. 62-133.9;

- A lack of any adjustment for naturally occurring, customer-driven EE captured in the company load forecasts;

- Assumptions of unreasonably high participation rates that are not reflective of the current data for the utilities;

- Reliance on market potential studies completed before the passage of the Energy Independence and Security Act of 2007;

- A lack of any discussion of equipment life (also referred to as Rate of Turnover); and

- The inclusion of below efficiency standard impacts already captured in the utilities' load forecasts, thereby double-counting potential savings impacts.

Duke noted that SACE focused its criticism of the Company based on its comparison to what it deems a leading utility can achieve and alleged that Duke continues to underestimate its EE potential in its IRP. SACE also blamed the industrial opt-out provision of G.S. 62-133.9(f) for lost EE savings opportunities and criticized Duke for failing to perform a new market potential study for its IRP.

Duke argued that, like NC WARN, SACE relied upon ACEEE data to support its market potential assessment and overlooked other current, region-specific information that informs reasonable expectations with respect to the realistic market potential for EE in Duke's service territory. The 2009 EPRI study estimated the economic potential for the Southern region to be 4.4% over 10 years, not the 7.2% to 13.6% cited by SACE in reliance upon ACEEE's analysis. Also, due to the lower than average electric rates and monthly bills that Duke's customer enjoy, some EE programs that work well in other markets may not be as attractive to customers or even cost effective. According to Duke, the ultimate driver of EE savings achievement is customer participation and choice. The Company is striving to achieve its High DSM case, which exceeds the estimated EE market potential developed by EPRI, but cannot assume it is going to happen without a track record of real results. For purposes of the 2010 IRP, the Company's Base Case for EE/DSM achievements represents a more reasonable and prudent input to the resource portfolio.

Baseload Requirements

NC WARN offered that, while there is no North Carolina definition of a baseload power plant, the Commission requires the electric utilities to file monthly Base Load Power Plant Performance Reports pursuant to Rule R8-53.[6] That rule requires reports on plant outages and generation capacity on each plant in the utility's nuclear fleet and listed coal plants, as well as all generating plants with greater than 500 MW maximum dependable capacity (MDC) utilizing coal or nuclear fuel. The 500 MW capacity limit clearly distinguishes between the baseload units that can be operated most of the time and the peaking units that are operated only when required. According to NC WARN, a useful distinction between the two resource types is that baseload units take time, up to days, to ramp up to full operation while peaking units, such as the natural gas combustion turbines (CT), can generate electricity in a far shorter period of time after being dispatched.

NC WARN explained that another way to view baseload is to include generating units that operate a certain percentage of the year, with rule-of-thumb estimates ranging from 35% up to 65% or more.[7] The U.S. Department of Energy, in its regulation, 10 C.F.R. 500.2, defines a baseload power plant as a power plant, the electrical generation of which in kilowatt-hours exceeds, for any 12-calendar-month period, such power plant's design capacity multiplied by 3,500 hours. This includes plants that operate for more than 40% of the year (3,500 hours divided by 8,760 hours in a year). In order to reduce the costs of operating peak plants, the baseload plants should be operated at peak times.

NC WARN noted that in its February 2, 2011 Base Load Power Plant Performance Report filing in Docket E-7, Sub 935, Duke reported that it currently has

[6] Duke currently is filing those reports in Docket E-7, Sub 935 and PEC in Docket E-2, Sub 971.

[7] NC WARN argued that, with increasing reliance on renewable energy sources, both the 500 MW definition and the 40% percentage definition may not hold up as combinations of solar and wind installations function as the equivalent to baseload. See Blackburn, "Matching Utility Loads with Solar and Wind Power in North Carolina: Dealing with Intermittent Electricity Sources," Institute for Energy and Environmental Research, March 2010. www.ieer.org/reports/NC-Wind-Solar.html.

11,854 MW in baseload units.[8] These include the nuclear units, Oconee 1, 2 and 3; McGuire 1 and 2; and Catawba 1 and 2; and the coal units, Belews Creek 1 and 2; Marshall 1, 2, 3, and 4; and Cliffside 5. The addition of Cliffside 6, scheduled to begin operation in 2012, brings Duke's total to 12,679 MW. In its January 27, 2011 filing in Docket E-2, Sub 971, PEC reported that it currently has 6,359 MW in baseload units, including the nuclear units, Brunswick 1 and 2, Harris 1 and Robinson 2, and the coal units, Mayo 1 and Roxboro 2, 3, and 4.

According to NC WARN, these total baseload capacity figures are useful in looking at the load duration curves submitted in each of the IRPs. A load duration curve places the MW load on the system for each of the 8760 hours in the year and the resulting curve shows the annual range of load from the lowest load needed for an autumn night, as an example, to the highest peak on a summer afternoon.

NC WARN stated that Duke provided two load duration curves in its IRP, Figure 3.1 (without EE) on page 54, and Figure 3.2 (with EE) on page 57. The load range for 2010 is 4500 MW at the lowest end and almost 17,000 MW at the upper end, with the average 2010 hourly demand approximately 10,900 MW. NC WARN argued that an important factor emerges from reviewing Duke's load duration curves. When all of its baseload plants are in operation (12,679 MW), they provide more electricity than is needed for 87% of the hours in a year; in other words, not all of the existing baseload units can operate for most of the year. For most of the year, the plants are either shut down and idle or spinning (still operating but not connected to the grid).[9]

NC WARN explained that, in its load duration curves, Duke then forecasts increases in load for each of the hours for 2015, 2020 and 2025.[10] Even using the load duration curve without EE, Duke still has excessive baseload through 2025; with Duke's projected EE programs, the current baseload plants provide excessive load for more than 50% of the year. With additional EE measures or combined renewable energy sources, less and less baseload will be needed.

NC WARN stated that, from its twelve-month summary in its January 27, 2011 filing in Docket E-2, Sub 971, PEC shows a total of 6,359 MW for its 500 MW-plus baseload units. In its IRP, at pages B-1 through B-4, PEC designated 7,373 MW as baseload resource type by including several smaller coal plants, Asheville 1 and 2, Robinson 1, in its baseload total. PEC's load forecast curves in its IRP, pages 26-28,

[8] In its Base Load Power Plant Performance Report, Duke included Marshall 1 and 2, each having an MDC of 380 MW. These plants are operated primarily as baseload units and are included in the Duke totals used herein.

[9] Duke also uses baseload power as part of its pumped storage facilities, pumping water to an upper reservoir to release in peak periods. Duke includes a portion of these baseload plants as part of its reserve margin.

[10] NC WARN noted that the load duration curves show a substantially greater increase in growth for the hours requiring the lowest load than for peak hours.

show that for approximately 60% of the hours in the year 2010, not all of the designated baseload plants were required to meet its load.

According to NC WARN, in the IRPs, the utilities continue to show a need for baseload additions in their North and South Carolina jurisdictions. In its IRP, page 81, Duke is proposing two units at the Lee Nuclear Station in Gaffney, South Carolina, forecasted to be in operation in 2021 and 2023. Taking a more realistic approach, PEC advanced three scenarios in its IRP. While it has apparently backed away from its proposal to build new reactors at the Shearon Harris site, it still continues to include new baseload units in two of its three scenarios. PEC's preferred scenario, Plan A, proposes two jointly owned nuclear plants with it owning approximately 25% share of each plant. Plan B is a much more prudent approach assuming a fairly aggressive control of carbon dioxide. It contains no nuclear units, and the difference in generation consists of natural gas-fired combined cycle (CC) plants. Lastly NC WARN stated that Plan C shows two units at the Shearon Harris site in Wake County, but is highly unlikely as the scenario assumes, among other things, low nuclear construction costs.

In response, PEC stated that NC WARN's comments are based upon several incorrect assumptions. The first such assumption is that baseload generation is any supply-side resource with a capacity factor greater than 40%. Using this definition, NC WARN then creates a load duration curve that purports to support its claim that PEC and Duke have excess baseload generation. NC WARN's baseload definition sweeps in many intermediate load-following plants, including CC and intermediate coal plants. PEC's baseload coal plants are described in the testimony of PEC witness Dewey Roberts in Docket No. E-2, Sub 976. He stated that these plants have capacity factors of over 70%. Mr. Roberts also testified that PEC's baseload nuclear plants had capacity factors of over 91%. Finally, Mr. Roberts explained that even PEC's intermediate load following plants have capacity factors in excess of 50%. Thus, NC WARN's unique definition of baseload is so broad as to include all of PEC's plants except its simple cycle CT peaking units.

Importantly, according to PEC, resource planning does not hinge on administrative definitions of baseload, intermediate, or peaker. Instead, PEC's resource planning considers the load and energy needs of its customers, then models the dispatch of existing resources to meet these load and energy requirements, including necessary reserves, and identifies additional resources needed to reliably meet the remaining energy and load at lowest reasonable cost. The timing and characteristics of future capacity needs are determined by sophisticated industry-accepted modeling. NC WARN appears to be trying to define the capacity factor of baseload as low as 40% to include wind and solar as baseload. However, neither can achieve even that level of operation. Solar has, at best, a 25% capacity factor, while wind can generally achieve no greater than a 35% capacity factor.

PEC explained that, furthermore, wind and solar are each more expensive than PEC's current net asset value on a $/kW basis, and since PEC would have to add 2 MW of wind and solar generation to equal 1 MW of replaced capacity, the net effect for PEC would be at least a doubling of its capital costs. Further, the REPS structure recognizes that the cost of wind and solar each exceed avoided cost as demonstrated by actual contracts to date. Therefore, even considering that wind and solar provide free energy, a combination of the capital costs of wind and solar would far exceed avoided cost, without even taking into account the embedded cost of the generation to be shut down. NC WARN's approach overlooks the many important considerations in resource planning, including availability, reliability, dispatchability and overall cost of the resource mix.

In its reply comments, Duke stated that NC WARN's arguments are primarily based on a pessimistic view of load growth in the Company's service territory, its application of two outdated planning concepts, and several fundamental errors. NC WARN devoted four pages of comments to an argument that Duke already has excessive amounts of baseload capacity. NC WARN stated that, "[w]hen all of its baseload plants are in operation (12,679 MW) they provide more electricity than is needed for 87% of the hours in a year." NC WARN's 87% calculation results from determining the point where the 2010 Duke load duration curve, presented on pages 54 and 57 of the 2010 IRP, meets the 12,679 MW level.

Duke maintained that NC WARN's calculations and conclusion regarding Duke's alleged lack of need for baseload capacity are plainly wrong. First, NC WARN grossly miscalculated the Company's actual baseload capacity available to serve its customers. NC WARN's calculation included the full Cliffside Unit 6 capacity (825 MW), which was not available in 2010, and also included the entire capacity of Catawba Nuclear Station, of which Duke only owns 19.26%. Because the load duration curve in the 2010 IRP excluded that portion of the Catawba Owner's load for which Duke has no obligation to serve, the capacity calculation must also exclude the 1,109 MW portion of Catawba that is not retained by Duke. Correcting these two errors would remove 1,934 MW, reducing the 12,679 MW figure used by NC WARN to 10,745 MW. Instead of 87%, the corrected crossing point should result in a figure closer to 60%.

Duke argued that the use of load duration curves as a planning methodology has long been recognized as inaccurate and inadequate for determining optimal capacity mix for a generation system. The inaccuracy of this methodology is clearly illustrated through a simple examination of Duke's actual generation records for 2010. As a group, Duke's fourteen units that operate as baseload capacity for the system were in reserve shutdown (available, but shut down or idle) for 4,512 hours out of a total of 122,640 hours (14 x 8760) during the year. That represents 3.68% of the hours over an entire year when those baseload units were available, but not generating electricity for Duke's customers. When the actual data is compared to NC WARN's 87% miscalculation, as well as its patently false statement that "[f]or most of the year, the plants are either shut down and idle or spinning (still operating but not connected to the grid)," it is clear that NC WARN does not understand the facts that underpin the Company's resource planning and utilizes flawed methodology to criticize the Company's resource plan. Duke argued that these flawed conclusions presented by

NC WARN are exactly why modern planning tools have replaced the use of load duration curves in determining an optimal capacity mix for resource planning purposes.

Cost of Additional Nuclear Generation

NC WARN argued that, regardless of the Commission's views on the risks and benefits from nuclear baseload units, the projected costs of this source of electricity have risen exponentially to the point they simply cannot be considered in the least cost mix. The cost of each new nuclear unit nationally is now in the $10 - 12 billion range, and very few are actively being considered.[11]

NC WARN reasoned that the IRPs, as filed with the Commission, contain little justification for the costs of the proposed nuclear units and even less discussion about the risks associated with proceeding with these large-scale projects. If the utilities continue to go ahead with the proposed plants, electricity bills will increase considerably over the next decade (or longer, given likely construction delays). These large nuclear units, each more than 1050 MW, would require large reserve capacity in case they are out of operation, increasing the costs even more. The construction and operation of these new nuclear plants are risky in terms of the costs to the ratepayers and taxpayers, as well to the overall economy of North Carolina. The risk is evident in that none of the current nuclear proposals are funded by financial institutions, i.e., Wall Street, and only a limited number of direct incentives, such as loan guarantees, have been made available from taxpayer-funded federal government programs.

NC WARN explained that, while nuclear costs are projected to continue to rise, the costs of renewable energy have consistently decreased. In his July 2010 paper, Dr. John O. Blackburn reviewed the costs of solar energy and nuclear power plants and determined that in 2010 solar energy has finally become less expensive than nuclear energy.[12] The study included all subsidies for both technologies and compared the cost per kWh generated by each. An important consideration in the Commission's review of the IRPs is that the cost of solar energy and other renewable energy sources is expected to continue to decrease while projected costs of nuclear power plants have risen steadily for the past decade and are expected to increase even more over time.

NC WARN argued that Dr. Blackburn's finding is confirmed in depth by the U.S. Energy Information Administration (EIA). The EIA, in its most recent Annual Energy Outlook, AEO2011, determined that the updated overnight capital cost estimates for nuclear power plants were 37% above those in the AEO2010, while photovoltaic technologies dropped by 25% in the same year. Using the definition of "overnight capital cost" from the World Nuclear Association, a supporter of nuclear energy worldwide,

[11] See, e.g., Wald, "New Nuclear Plant Projects Stalled by Market Forces," February 8, 2011.

[12] Blackburn and Cunningham, "Solar and Nuclear Costs – The Historic Crossover: Solar Energy is Now the Better Buy," July 2010. Available at www.ncwarn.org/?p=2290.

> Capital costs comprise several things: the bare plant cost (usually identified as engineering-procurement-construction - EPC - cost), the owner's costs (land, cooling infrastructure, administration and associated buildings, site works, switchyards, project management, licenses, etc), cost escalation and inflation. Owner's costs may include transmission infrastructure. The term "overnight capital cost" is often used, meaning EPC plus owners' costs and excluding financing, escalation due to increased material and labor costs, and inflation.

NC WARN noted that the last items of financing, increased material and labor costs, and inflation are the components that raise the projected costs of nuclear power dramatically, and particularly if construction does not stay on schedule.

According to SACE, neither Duke nor PEC has provided, either in its IRP or in response to a data request, any supporting evidence or documents that form the basis for the nuclear cost estimate. There are a number of factors for the great uncertainty regarding the ultimate construction cost of Duke's proposed Lee Nuclear Station or any new nuclear power plants in the region.

PEC observed that, continuing with its attack on new nuclear generation, NC WARN stated, "These large nuclear units, each more than 1,050 MW, would require large reserve capacity in case they are out of operation, increasing the costs even more." PEC argued that NC WARN offered no support for this statement because it is unsupportable. These units require no more reserves than PEC's other units that are nearly 1,000 MW in size.

PEC continued, noting that NC WARN next suggested a cents/kWh comparison between EE and supply options. This is another example of a one-dimensional comparison of "apples and oranges" that may appear to support NC WARN's premise, but is meaningless and unsupportable in the context of an IRP proceeding. A CT, for instance, may cost 30 cents per kWh because it does not generate much electricity, but that does not mean PEC would never select it as the least cost resource. The only meaningful comparison for cost to customers is the final rates they pay (or as a proxy, revenue requirements when only supply-side resources are considered) based upon the total least cost resource mix proposed, including total system fuel impacts. In addition, the amount of EE reasonably and economically available must also be considered in this analysis.

PEC noted that SACE asserted that PEC did not consider nuclear construction cost uncertainty in its analysis. In response, PEC referred SACE to Appendix A of PEC's 2010 IRP, in which PEC presented sensitivities (see page A-4) that were +/- 30%; and to page A-7, where PEC used the +30% figure for 2 of the 3 scenarios. Importantly, PEC's IRP does not include the construction of a new nuclear unit. The only new nuclear generation is the potential participation in a regional project, and PEC would have to obtain Commission approval prior to participating in such a project.

According to Duke, NC WARN continues to make the assertion that the projected costs of new nuclear resources "have risen exponentially to the point they simply cannot be considered in the least cost mix." The Company's analysis of its own proprietary and the publicly available information indicates otherwise. Duke's most recent projection of the overnight cost of building two twin AP1000 units at the proposed Lee Nuclear Station site in Cherokee County, SC, is $11 billion, in 2010 dollars, exclusive of financing costs and exclusive of the impacts of inflation. This estimate was developed for Duke by Westinghouse Electric Company, LLC, and its consortium partner Shaw, Stone and Webster, Inc. (collectively WEC/SN). WEC/SN Engineering, Procurement & Construction (EPC) consortium is the EPC contractor for the two other AP1000 projects in the United States, Southern Company's Vogtle Nuclear Plant (Vogtle) and South Carolina Electric & Gas's (SCE&G) V.C. Summer Nuclear Plant (Summer), and is similarly involved in the construction of the AP1000 units in China. There are currently four AP1000 units under construction in China, and both Vogtle and Summer are ahead of Duke's Lee Nuclear Station in both licensing and construction. Duke has been following all of this activity closely, and early experience suggests that the construction work is going well as the AP1000 projects remain within schedule and budget and are moving forward as expected. On October 21, 2010, SCE&G, at an allowable ex-parte briefing, provided an update to the Public Service Commission of South Carolina (PSCSC) on the construction of the Summer Nuclear Plant. At that update, Steve Byrne, SCE&G Chief Generation Officer, told the Commission that the Summer project was moving forward as expected and that SCE&G had just completed negotiations with WEC/SN to move additional costs from the target category to the firm/fixed category. According to Mr. Byrne, approximately two-thirds of the Summer plant cost is now in the firm/fixed category. Additionally, Mr. Byrne explained that due to lower escalation rates, the new project cost projections were reduced by approximately $1 billion to $9.6 billion versus the initial estimate of $10.6 billion.[13] Additionally, SCE&G's most recently filed quarterly report, filed on February 14, 2011, in Docket No. 2008-196-E pursuant to PSCSC Order No. 2009-104(A), indicates that it is on track to complete the two units at Summer on its scheduled completion dates within the original construction cost forecast.

Duke explained that additionally, the new nuclear licensing process, involving the Nuclear Regulatory Commission's (NRC) issuance of the combined construction and operating license (COL) for the Vogtle, Summer and Lee Nuclear Station projects, will also help with the cost certainty on new nuclear projects. By the time the Lee Nuclear Station project is ready to start construction, the NRC will have reached its decision regarding the approval of the AP1000 design, and engineering and design for the AP1000 will be close to 100% complete, thereby bringing greater certainty to construction plans.

[13] The transcript of the SCE&G briefing is available on the PSCSC's website at the following web address: http://www.psc.sc.gov/exparte/epb-2010-10-21/epb-20101021 Transcript Presentation Materials.pdf.

Duke recognized that the cost estimates used in its planning models are very important, and as such Duke stated that it continues to monitor all available projects and industry data to ensure that its estimates are in line with recent experience and based on the best available information at that time. Duke further stated that it believes that all recent experience in China and at the two plants in the Southeast, as well as the recent trend in industry data of lower escalation rates, supports the current level of its cost estimates used for resource planning purposes. Additionally, Duke noted that it models various project risks specifically relating to increases in capital cost and incorporates such analysis into the IRP through the +20%/-10% Nuclear Capital Cost Sensitivity used in its IRP analysis.

Duke noted that SACE, like NC WARN, also questioned Duke assumptions regarding the cost and schedule for construction of a new nuclear generating facility. SACE pointed to the history of the initial nuclear build-up in the United States and certain isolated examples of current projects developing different technologies to assert that the Company's estimates are inaccurate. As articulated above in response to NC WARN's comments, Duke stated that it believes that its current estimates for the schedule and cost of the proposed Lee Nuclear Station are reasonable and based upon the best information available at this time from the appropriate industry sources.

With respect to the schedule, Duke stated that it is important to include a full description of the construction window as well as the window for start-up and fuel load. The Lee Nuclear Station schedule currently shows deployment to the site for construction in the summer of 2014 for two years of initial site construction activities. At the end of construction is a six month window for fuel load and initial start-up testing. When defining the construction window from site deployment to commercial operation, the Lee Nuclear schedule represents an overall construction schedule duration approaching seven years for Unit 1. Duke believes this is a very realistic schedule given:

- The AP1000 design and engineering will be substantially completed before construction starts;

- A stable NRC licensing platform avoids introduction of new requirements;

- The AP1000 design includes a simplified nuclear island design with passive safety features;

- Advanced modular construction techniques are currently being proven during construction of AP1000 reactors in China, and additional construction technique evaluation for the AP1000 in the United States will occur before the construction of Lee Nuclear Station begins;

- The extensive use of proven Pressurized Water Reactor (PWR) technologies; and

- The significant level of planning in coordination with the WEC/SN consortium that has gone into developing the current schedule.

According to Duke, a key consideration in Duke's selection of the AP1000 design was its simple passive design features and extensive use of proven PWR technologies. The passive design and use of proven technologies are strong mitigants to the asserted risks. The Company's approach is consistent with recently issued guidance from the Institute for Nuclear Power Operations (INPO), which states that "[m]odular design and construction, done correctly, can significantly reduce both overall construction cost and time. The decision to use modular construction techniques should be made at the very beginning of a project and factored into the overall design and constructability reviews. The use of modular construction can generally reduce the overall weight of steel by 20 to 40 percent."[14] Additionally, despite SACE's speculative remarks to the contrary, supply chain capacity has continued to expand while demand has reduced since the economic downturn of 2008.

Duke asserted that the NRC has recently affirmed the design certification schedule for the AP1000, which will lead to its certification of the AP1000 design, in its current revised design, in September 2011. The AP1000 reference COL for Vogtle is expected to be issued within months of the NRC certification of the AP1000 revised design. Duke stated that it continues to diligently monitor lead times for critical plant equipment, licensing activities and construction operations at all AP1000 design facilities both in the U.S. and abroad to stay current on the best available relevant information relating to the future construction of the Lee Nuclear Station. Based on its internal analysis and relevant industry information, Duke stated that it firmly believes that its current schedule for the proposed construction of Lee Nuclear Station is reasonable and prudent.

Greenhouse Gas Emissions

According to SACE in its comments, Duke acknowledged the risk that federal regulation will require reductions of GHG emissions. However, Duke did not present any evidence in its 2010 IRP that it has a realistic plan for reducing its GHG emissions during the planning period.

SACE stated that Duke recognized that it is likely that Congress will adopt mandatory GHG emission legislation at some point, although the timing and details are highly uncertain at this time. Duke also recognized that the Environmental Protection Agency (EPA) is undertaking actions to regulate emissions of GHG from new and modified major stationary sources, including power plants. Moreover, the air quality permit for the new Cliffside Steam Station Unit 6 requires that Duke retire Cliffside Units 1-4, plus an additional 800 MW of coal-fired units located in North Carolina by the end of 2018. In addition, the air permit requires the company to take additional actions

[14] INPO 11-001, February 2011, INPO/Utility Benchmarking Current Domestic Modular Construction Facilities.

to render Cliffside Unit 6 carbon neutral by 2018, subject to Commission approval and "appropriate cost recovery." Nonetheless, Duke currently projects that its system carbon dioxide (CO_2) emissions will increase between 2010 and 2030, whether it adds new nuclear units or just new natural gas-fired units.

SACE explained that it is not surprising that Duke is projecting that its annual CO_2 emissions will rise between 2010 and 2030. Even though Duke is planning to retire more than 1,600 MW of existing coal capacity, emissions reductions from those retirements will be more than offset by increased emissions from the new Cliffside Unit 6 coal plant. Cliffside Unit 6 will emit approximately six million tons of CO_2 each year, or more than two million tons of CO_2 per year more than the 2008 CO_2 emissions from all of the coal units that Duke proposes to retire. In addition, Duke is planning to add more than 4,000 MW of new gas-fired CC and CT capacity over the planning period. Although they emit significantly less per MWh than coal-fired facilities, gas-fired units do emit CO_2.

SACE noted that, like Duke, PEC recognized that it is likely that Congress will adopt mandatory GHG emission legislation at some point and that EPA is undertaking actions to regulate emissions of GHG from power plants. Despite this acknowledgment, PEC provided no evidence in its 2010 IRP that its proposed resource plan (or the two alternatives it considered) actually will result in any, let alone significant, reductions in the GHG emissions from the Company's generation fleet. Unlike Duke, PEC did not even include a figure in its IRP showing the trajectory of future annual CO_2 emissions under its proposed and alternative resource plans.

SACE observed that PEC is proposing to retire 1,500 MW of its existing coal-fired units and to replace those retired units with 1,500 MW of state-of-the-art gas-fired generation. Although natural gas-fired generation emits only about 60 percent as much CO_2 per MWh as coal-fired units, the new state-of-the-art gas units being added by PEC can be expected to operate more often than the coal units slated for retirement have operated in recent years, especially given projected low natural gas prices. This means that it is possible that the Company's replacement of existing coal by new gas CC units may not result in any significant reduction in PEC's system CO_2 emissions. At the same time, the Company's proposed resource plan will add thousands of MW of additional CC and CT capacity during the 2010 to 2030 planning period. SACE argued that, as a result, it is reasonable to expect that the Company's annual system CO_2 emissions will not go down much, if at all, during the planning period.

In its reply comments, PEC responded that, while SACE claimed neither Duke nor PEC has shown in its 2010 IRP that it has a realistic plan for reducing GHG emissions, this is incorrect. Appendix A to PEC's 2010 IRP explicitly shows that PEC considered the potential impact of carbon regulation in performing its scenario analyses. Implicit in the high and low carbon regulation scenarios is the reduction of GHG emissions.

Regarding natural gas-fired generation, PEC stated that it is retiring 1,500 MW of coal generation and replacing it with new natural gas-fired generation. PEC noted that SACE did not object to PEC being awarded the certificates of public convenience and necessity to construct the new natural gas-fired generation, and supports PEC retiring the coal generation. Yet now, SACE in this proceeding argued that even though natural gas-fired generation emits only about 60 percent as much CO_2 per MWh as coal-fired units, PEC can be expected to operate the new natural gas-fired generation more often than the coal units it is replacing and, therefore, emit the same amount of greenhouse gases. PEC reasoned that one must first wonder, if a utility is not to use nuclear, coal, or natural gas, how can it possibly be expected to meet the electricity needs of its customers? But more to the point, in the certificate proceedings in which the Commission approved PEC constructing the new Wayne County and Sutton natural gas facilities, one of the key cost justifications was these new units would allow PEC to better comply with new or future GHG emissions requirements due to their reduced emissions.

According to Duke in its reply comments, SACE further criticized Duke for allegedly failing to have a realistic plan to reduce GHG emissions over the planning horizon and for failing to evaluate the economics of the continued operation of its coal generating facilities with environmental controls already installed. The Company disputed this contention. Duke's IRP has been designed and modeled to provide affordable, reliable, and clean resources to meet future customer needs in a carbon-constrained environment. From the time the Company began to incorporate potential GHG regulation into its resource planning process in 2006, Duke has assumed a cap-and-trade program would be enacted. Even now, with the change in leadership in Congress, many believe that GHG constraints in the form of regulation from the EPA are likely to be implemented. Under this assumption, the Company has sought to develop a cost-effective portfolio of resources that meets customer energy needs while complying with the assumed GHG regulation. Duke stated that its results consistently demonstrate that this is best achieved through a balanced portfolio that includes nuclear, coal, gas, hydro and renewable energy generation, end-use EE, and the purchase of GHG emission allowances. As the proposed emissions cap declines over time, the price of GHG allowances will likely increase. As the prices of GHG allowances increase, additional end-use EE, nuclear, natural gas, and renewable generation will likely be more cost-effective and, over time, will lead the Company to replace coal-fired generation resources as those resources near or reach the end of their economic lives.

Duke explained that coal-fired generation resources, particularly those with environmental controls, will continue to be an important part of the portfolio through at least 2030 over a range of potential GHG allowance prices. To the extent such resources become less economic to operate as part of the Company's portfolio in the future, Duke will make all necessary adjustments to ensure that its generation system is being planned, constructed, and operated at the least reasonable cost to its customers. The Company's current coal fleet includes some of the most economic units on the system, as evidenced by the high capacity factor projections in the 2010 IRP. As Cliffside Unit 6 comes online, the efficiency of Duke's coal fleet will improve even more as the older, less efficient units move even further up the dispatch stack and will ultimately be retired by 2015. Duke will continue to evaluate new GHG regulations as they develop and analyze their ultimate impact on its current generating system. At the present time, the Company believes the selected portfolio within the 2010 IRP, which includes a combination of new nuclear, natural gas, and renewable resources, as well as additional EE and the retirement of all coal generating units without environmental controls, represents the best plan to meet its customers energy needs in the most clean, affordable and reliable way possible over the planning horizon.

Existing Scrubbed Coal Units

According to SACE, neither Duke nor PEC presented in its 2010 IRP any specific analysis of the risks faced by its existing scrubbed coal plants, any assessment of what controls will be needed to be added at each of these units, or whether it will be more economic to add such needed controls than to retire the unit(s). SACE asserted in its comments that this is a serious flaw. Duke's responses to a SACE data request reveal that the Company has prepared some analyses of the costs of adding controls to some of its coal units with SO_2 scrubbers that it does not currently plan to retire. PEC also provided in response to a data request several studies of the cost and economics of retiring some of its older coal units. In addition to showing that retirement of the units at Cape Fear and Weatherspoon is the more economic option, these studies also showed that retirement of the Robinson coal plant by 2014 is the more economic option in almost all of the scenarios studied. SACE argued that the analyses prepared by Duke and PEC should be presented to the Commission in the companies' IRPs to allow the Commission and other parties a full opportunity to review and critique them. In addition, PEC should analyze the economics of the retirement versus continued operation of each of the existing coal units that the Company is not currently planning to retire in the near future.

In its reply comments, Duke explained that coal-fired generation resources, particularly those with environmental controls, will continue to be an important part of its portfolio through at least 2030, over a range of potential GHG allowance prices. To the extent such resources become less economic to operate as part of the Company's portfolio in the future, Duke stated that it would make all necessary adjustments to ensure that its generation system is being planned, constructed and operated at the least reasonable cost to its customers. According to Duke, the Company's current coal fleet includes some of the most economic units on the system as evidenced by the high capacity factor projections in the 2010 IRP.

In its reply comments, PEC stated that its analysis of retiring unscrubbed coal units in its Lee/Wayne and Sutton filings Docket No. E-2, Subs 960 and 968, demonstrated that a significant part of the cost of continued operation was the addition of scrubbers and Selective Catalytic Reduction (SCR) to those units. Scrubbed units would not face these costs, and the existing scrubbers do address, in part, future environmental requirements, including mercury.

Overly Optimistic Growth Projections

According to NC WARN, a review of past IRPs shows that both PEC and Duke have consistently lowered most of their successive projections of increased electricity demand. In comparing its 2005 and 2010 IRPs, Duke's forecasts for peak demand in 2015 decreased by 20.4%. During the same time, the projections for 2025 decreased by 2.0%. In comparing PEC's 2005 and 2010 IRPs, the utility showed no change in peak demand forecast for 2015, but it showed a 9.3% decrease in total sales in 2015. As the IRPs show, both Duke and PEC have experienced nearly flat growth in electricity demand for several years. PEC's actual retail sales grew only 0.3% annually from 2000-2009, and Duke's grew only 0.7% annually from 1994-2009. PEC expects its retail sales of electricity to increase by 1.4% annually through its 15-year planning period. Duke is optimistically projecting 1.5% through its 20-year planning horizon.

According to NC WARN, in its 2009 rate case, Docket E-7, Sub 909, Duke adjusted earlier projections to reflect the impact its rate hike would have on customer usage. The revised estimates projected a slightly negative trend in retail sales over the next five years. Notably, these projections were made in early 2009, before the worst impacts of the current economic recession. It seems likely that because of the current economic situation, consumers will remain cautious and growth in sales will remain flat or decrease, especially as any new purchases of appliances, homes, lighting, HVAC systems and turbines will be considerably more energy efficient than current stock.

According to PEC, NC WARN once again challenged the veracity of PEC's load forecast. In support of its attack, NC WARN asserted that PEC's retail sales only grew 0.3% annually from 2000 to 2009. PEC argued that NC WARN has taken this data out of context to create a very misleading picture of the forecast. PEC's industrial retail sales declined by almost 30% from 2000, (when industrial accounted for about 36% of total retail sales) to 2009. Over the same period, PEC's residential and commercial sales increased by 20%, or about 2.1% per year. In the forward looking years, PEC forecasts a smaller rate of growth in the industrial sector, about 0.8% per year. The growth in PEC's residential and commercial sectors amounts to about a 1.6% growth rate, which is entirely consistent with history. Unless NC WARN wants to present a scenario of continued decline in the industrial sector in NC, and its accompanying loss of jobs and economic health, there is no basis for this assertion.

PEC asserted that, furthermore, in 2008 the Commission conducted a hearing to evaluate the utilities' forecasting process and found it valid. The Public Staff, in its comments in this proceeding, concluded that the assumptions that underlie PEC's peak and energy forecasts are reasonable; that PEC has employed accepted statistical and econometric practices used in forecasting; and that PEC's peak load and energy sales forecasts are reasonable for planning purposes. The Public Staff's conclusions are consistent with the Commission's findings in the 2009, 2008, 2007 and 2006 IRP proceedings.

In its reply comments, Duke maintained that all customer EE activities are captured in the load forecast since that represents metered consumption and the actions of customers in determining how much energy to consume. All of the activities and customer decisionmaking processes associated with energy consumption highlighted by NC WARN are reflected in the historical data and thus represented in the forecasting models used to prepare the Company's load forecast. Similarly, it is an overstatement that load growth has been flat for the past several years. Recent economic events have primarily impacted the industrial sector. However, industrial load growth increased 7% from 2009 to 2010. In addition, excluding the industrial sector, retail load growth has been 1.5% per year for the period 2004 to 2009. It is incorrect to claim that recent slow growth in total sales should imply that it will continue into the future.

Duke stated that the recent declines relating to kWh sales are clearly related to the housing market bust in 2007-2008 and resulting recessionary impacts on the national and regional economies. It is, however, unreasonable to assume that its service territory will continue to experience such a reduction in growth over the entire planning horizon for this IRP. Duke stated that it believes that its load growth projections incorporated into the 2010 IRP are reasonable for planning purposes and that this view is shared by the Public Staff in its comments.

Convening a Workshop or Workgroup

SACE stated in its comments that, if the Commission elects not to schedule an evidentiary hearing on the utility IRPs, the Commission should consider convening a workshop on a limited set of issues. Such a workshop could provide an opportunity for the electric utilities to present their IRPs, and for intervenors to present their analysis of those IRPs to the Commission, and for the Commission to question the parties' representatives on the issues it identifies, without the need for formal witness testimony. In addition, or in the alternative, the Commission may wish to consider establishing a collaborative workgroup to discuss and report on certain issues related to the IRPs and the resource planning process. SACE suggested that such a workgroup would be more effective if it continued to meet after the conclusion of the present docket, so that the workgroup's suggestions and recommendations could inform the utilities' development of the 2011 annual reports and 2012 biennial reports. To enable the full participation of the Public Staff, the Commission may wish to engage a third-party facilitator if it decides to convene such a workgroup.

Duke asserted that it finds SACE's proposal for a technical workshop unnecessary at this time given the opportunity that the parties have had to review and comment upon the IOUs' IRPs.

PEC did not comment on this issue in its reply comments or proposed order.

Conclusions

The Commission finds that PEC and Duke have adequately addressed the issues related to EE, DSM, and portfolio selections in their reply comments. Likewise, both PEC and Duke have offered responses to the issues regarding baseload requirements, the cost of new nuclear generation, GHG emissions, and existing scrubbed coal units that the Commission finds satisfactory and appropriate.

The issue related to overly optimistic growth projections by both PEC and Duke, raised by NC WARN, was also raised by NC WARN in the 2010 evidentiary hearing on IRPs. The Public Staff has reviewed these current forecasts, as it does in every IRP proceeding, and found them to be reasonable for planning purposes. The Commission finds again, as it did in its Order in Docket No. E-100, Sub 124, issued on August 10, 2011, that the growth projections made by PEC and Duke and the resulting energy and peak load forecasts are reasonable and appropriate.

As to the SACE issue of convening a workshop or workgroup, the Commission agrees with Duke that such a process is unnecessary. The existing IRP process allows ample opportunity for intervenor comment and, in fact, allows an intervenor to file an integrated resource plan or report of its own as to any utility.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 6

In its comments, the Public Staff stated that, in addition to new generation to meet load growth, and facilities previously scheduled for retirement, PEC should have also incorporated retirement of additional coal-fired capacity as required by Commission Order dated January 28, 2010, in Docket No. E-2, Sub 960. The retirement plan submitted by PEC in this docket indicated that all unscrubbed coal generation would be retired by December 31, 2017. Robinson Unit 1 is not scrubbed and is not included in the planned retirements. PEC's filing should have included all required retirements.

In its reply comments, PEC responded that it does not understand this recommendation. PEC indicated in its 2010 IRP that it is still evaluating the best course of action for its Robinson coal plant in South Carolina. In contrast to PEC's Cape Fear, Sutton, Lee and Weatherspoon coal plants, all of which PEC has committed to retire by the end of 2014, PEC's Robinson coal plant does have some environmental controls. Also, the natural gas-fired generation to be constructed at PEC's Sutton and Lee plant sites is only sufficient to replace the coal generation at PEC's Lee, Sutton, Cape Fear and Weatherspoon sites. The retirement of PEC's Robinson coal plant would require the construction of additional natural gas-fired generation.

Conclusion

In the absence of continued opposition by the Public Staff, the Commission is of the opinion that PEC has adequately addressed this issue in its reply comments and, therefore, the Commission concludes that the response provided by PEC is satisfactory.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 7

In its comments, the Public Staff requested that PEC and Duke file with their reply comments the specific explanation required by Rule R8-60(i)(3) for each year in which the revised projected reserve margin exceeds plus or minus 3% of the target.

PEC

In its reply comments, PEC stated that the explanation is straightforward. PEC's reserve margin exceeds 3% in those years immediately following the addition of new generation resources, which is to be expected. Resource additions are inherently "lumpy." They cannot economically be added in the exact amount needed each year to maintain an exact reserve margin. PEC's forecasted reserves exceed 3% of PEC's minimum capacity margin target in 2011 and 2012 as a result of the economic addition of the Richmond CC unit as demonstrated in Docket No. E-2, Sub 916. Reserves exceed 3% of PEC's minimum capacity margin target in 2013 and 2014 as a result of the economic addition of the Wayne County CC unit as demonstrated in Docket No. E-2, Sub 960.

Duke

In its reply comments, Duke acknowledged that its system reserve margin is projected to exceed its target reserve margin of 17% by more than 3% over the course of the planning period in the years 2012, 2013, 2014, 2021, 2023, and 2024. These projected increases in reserve margin are driven by the recessionary impacts to load and timing of additions of necessary system generating capacity. Specifically, the additions of Cliffside Unit 6 (825 MW) and the Buck CC facility (620 MW) contribute to the increased reserve margin in 2012, and the addition of the Dan River CC facility (620 MW) further increases the reserve margin above the 17% target in 2013 and 2014. However, by 2015, due to the assumed retirement of over 1,600 MW of coal fired capacity and 370 MW of CT capacity, the reserve margin moves back to within 3% of the Company's target. In 2021, Lee Nuclear Unit 1 (1,117 MW) increases the reserve margin to over 20%. The second Lee Nuclear unit (1,117 MW) in 2023 also increases the reserve margin over 20% in 2023 and 2024. By 2025, the reserve margin is projected to move back within the target range due to continued load growth.

Conclusion

The Commission finds that PEC and Duke have adequately answered the Public Staff in their reply comments.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 8

In its comments, the Public Staff requested:

a) That Duke identify in its reply comments the period during which the double-counting of avoided capacity cost benefits occurred and provide an explanation of the effect of the issue, on any data filed with the Commission, including whether the error influenced Tables 4.1 and 4.2 of the IRP, and provide calculations or other necessary data supporting its response.

b) That Duke should provide in its reply comments a list of all dockets filed with the Commission since January 1, 2005, that included any information, input data, or output results from the DSMore model affected by the double-counting issue.

c) That within 30 days, Duke should file in the respective dockets of each DSM program and pilot approved by, or pending before the Commission, a calculation showing the difference between the avoided cost capacity and energy benefits as originally filed, and the avoided cost benefits recalculated using the correct calculation methodology.

In its reply comments, Duke explained that the Public Staff, in its review of Duke DSM and EE programs, specifically the cost-effectiveness test results of the Company's Power Share Call Option (Docket No. E-7, Sub 953) generated by the DSMore model, observed a calculation of avoided production (energy) costs which seemed relatively high for a DSM program. The cost-effectiveness of the Power Share Call Option and Duke's other Power Share and Power Manager programs, approved in Docket No. E-7, Sub 831, is largely based on avoided capacity costs, and as such, the elimination of the avoided energy cost benefits from the cost-effectiveness results would not change the overall cost-effectiveness of any of the programs.

Duke explained that through the discovery process in this docket, it explained to the Public Staff that the high level of avoided production cost benefits improperly included an amount of avoided capacity cost benefits which were embedded in the inputs used to calculate the avoided production cost benefits. As the Public Staff described in its comments, this DSMore calculation methodology error resulted in a "double-counting" of the avoided capacity cost benefits in Duke's cost-effectiveness evaluations for its Power Share Call Option DSM program. The Public Staff correctly noted that the Company has since corrected the calculation methodology within DSMore to prevent future model runs from performing this incorrect double-counting calculation. The Public Staff also indicated that, based on further discussions with Integral Analytics, LLC, the developer of the DSMore software, it believes that the double-counting of the avoided capacity cost benefits was limited to the overstatements of dollar savings from avoided production cost benefits in the cost-effectiveness tests and did not affect the assumptions of the kilowatt capacity savings from DSM programs represented in Duke's 2010 IRP. Further, the Public Staff stated that it did not believe that any EE program evaluations were impacted by this error, and that the Company's

IRP did not need to be adjusted because of this issue. However, the Public Staff stated that it does believe that any erroneous cost-effectiveness test results filed with the Commission in connection with previous DSM program applications should be corrected and refiled in the appropriate dockets, along with an identification from Duke of the period during which the double-counting occurred and an explanation of the effect of the issue on any data filed with the Commission.

Duke has confirmed that the double-counting of avoided capacity cost benefits for its DSM programs occurred during the period of May 2007 to February 2011. As the Public Staff noted in its comments, only DSM programs were impacted, so any values related to EE programs were not impacted. Also, specifically relating to Tables 4.1 and 4.2 of the IRP, which show the respective base case and high case projected load impacts of the Company's EE and DSM portfolio of programs over the planning period, this double-counting did not impact the Company's EE and DSM forecasts as they contain only MW and MWh values. Only dollar amounts related to cost-based avoided production included in certain benefit/cost analyses for DSM programs were impacted. The resulting impact of the double-counting was that the subject DSM programs were shown to be more cost-effective than they otherwise should have been. In any future filings, Duke will remove any double-counting of benefits from all calculations of benefit/cost ratios for DSM programs.

In its reply comments, Duke stated that it will compile a listing of all dockets filed with the Commission since January 1, 2007, that included any information, input data, or output results from the DSMore model and will correct (1) any documents that contained incorrect avoided capacity cost benefits and (2) any documents that contained incorrect cost-effectiveness test evaluations resulting from the DSMore double-counting issue. However, due to the significant number of documents that must be reviewed to determine which may have been impacted, the Company proposed to submit such information within 60 days from the date of this filing. Duke submitted that this additional time was necessary to complete this request in order to properly identify all pertinent documents, correct any necessary miscalculations and supplement the relevant filings as necessary. Duke then filed this information on May 2, 2011.

Conclusion

Based on Duke's responses in its reply comments and its May 2, 2011 supplemental filing, the Commission concludes that Duke has adequately addressed the Public Staff's requests concerning this issue.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The Public Staff observed that French Broad and Blue Ridge did not file IRPs, although NCEMC did include French Broad's load forecast as an appendix to its IRP. Blue Ridge advised the Commission in a letter of July 6, 2009, that it would no longer file IRPs because it had entered into a full requirements power purchase agreement with Duke, and likewise French Broad purchases all of its power requirements from

PEC. Prior to 2007, Commission Rule R8-60(b) provided that the requirement to file IRPs applied only to PEC, Duke, DNCP and NCEMC. In that year the Commission amended subsection (b), in Docket No. E-100, Sub 111, to state that the requirement also applied to "any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources." The Public Staff stated that it believes that French Broad and Blue Ridge, which are responsible for procuring their own power supply resources, are now required by subsection (b) to file IRPs and should begin filing them next year.

In its reply comments, Blue Ridge stated that on September 1, 2006, it entered into a partial requirements power purchase agreement with Duke. Thereafter, on December 17, 2007, Blue Ridge entered into a full requirements power purchase agreement with Duke (the Blue Ridge Agreement). On October 1, 2010, the Blue Ridge Agreement was amended to extend the term until December 31, 2031, and to obligate Duke to provide REPS compliance services for Blue Ridge. Blue Ridge's current and future load requirements are included in Duke's load obligation set forth in Duke's IRP, dated September 1, 2010.

Blue Ridge explained that pursuant to the Blue Ridge Agreement, and as shown in Duke's IRP, Duke's services to Blue Ridge include the delivery of renewable energy resources to Blue Ridge, as well as REPS compliance and reporting services. In accordance with G.S. 62-133.8(c)(2)(e), Blue Ridge may rely on Duke to provide such services. Accordingly, Duke has aggregated the information required under Commission Rule R8-67 for Blue Ridge into its 2010 REPS compliance plan.

Blue Ridge argued that the filing of an IRP by Blue Ridge, separate and apart from the filing of Duke's IRP, which includes the information for Blue Ridge, would be unnecessarily duplicative. The information required of Blue Ridge by Rule R8-60 and R8-67 is included in the IRP filing of Duke. To require a separate filing by Blue Ridge itself would be an unnecessary expenditure of the time and resources of Blue Ridge in having to prepare such a filing, and of the Public Staff and the Commission in having to review it.

French Broad did not respond to this issue. GreenCo's consolidated REPS compliance plan includes French Broad.

Conclusions

Because both Blue Ridge and French Broad have full requirements contracts with utilities that have an IRP filing obligation, the Commission finds Blue Ridge's argument persuasive. Both Blue Ridge and French Broad are adequately covered through inclusion of their data in existing IRPs and REPS compliance plans.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 - 12

In its comments, the Public Staff requested:

a) That all EMCs include a full discussion in future IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6);

b) That Piedmont indicate in its reply comments whether its smart meter program is an EE program, and if so, file for Commission approval of the program pursuant to Rule R8-68; and

c) That EU provide in its reply comments and in future IRPs a more detailed description of the participation and savings related to specific DSM and EE programs, and more particularly any DSM or EE program it proposes to use to meets its REPS obligations.

Conclusions

None of the EMCs addressed these issues in reply comments. In fact, of the EMCs, only Blue Ridge filed any reply comments. The Commission agrees with the Public Staff and, therefore, requires that all EMCs shall include a full discussion in future biennial IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6); that if Piedmont determines that its smart meter program is an EE program, it shall file for Commission approval of the program pursuant to Rule R8-68; and that in future biennial IRPs, EU should provide a more detailed description of the participation and savings related to specific DSM and EE programs, particularly those its proposes to use to meet its REPS obligations.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The Public Staff stated in its comments that, during the 2010 summer, several instances occurred when PEC's reserve margins dropped to low single digit values. These instances coincided with both scheduled and non-scheduled maintenance of generation units, along with abnormally hot weather conditions. No actual emergency situations resulted from these events. The Public Staff argued that this illustrates the importance of the identification of the proper value to use for the reserve margin. At the same time, despite the abnormally hot weather, Duke's reserve margins stayed around 17%.

According to the Public Staff, an inadequate reserve margin results in emergency situations that may lead to expensive emergency purchases or the inability to carry full customer loads in some service areas. On the other hand, a higher than necessary reserve margin results in system costs that are greater than necessary to procure, operate, and maintain excess generation facilities, which results in higher customer rates.

The Public Staff noted that it has been a number of years since either Duke or PEC has conducted a comprehensive study to determine the appropriate reserve and capacity margin values to be used for the planning and operation of their respective systems, and prudent planning requires that such studies be conducted on a periodic basis. Therefore, the Public Staff recommended that the Commission require both Duke and PEC to conduct such studies as soon as practicable and incorporate the results in their IRP process and filings. The studies should determine the optimal level of reserves to provide generation reliability that considers the obligation to serve, the value of electricity, and the effect of outages, while minimizing the cost to ratepayers. It recommended that the studies include, but not be limited to, sensitivity analyses for factors such as the assumed levels of forced outages of generation facilities, assumed level of costs to customers for power outages, assumed values for reliable transmission capacity, and the assumed lead time for adding new generation units. The Public Staff further recommended that the utilities keep the Public Staff updated as they develop the parameters of the studies.

According to PEC, its 2003 reliability analysis formed the basis for its target capacity margin and the 2007 reliability analysis reaffirmed those findings. PEC argued that future updates should be driven by significant changes in input assumptions such as resource mix, outage rates, and load uncertainty. Given that there has not been a significant change in these assumptions, an updated study would produce results similar to the 2003 and 2007 analyses and, thus, an updated study is not warranted at this time.

With regards to PEC's reserve margin adequacy, the Public Staff commented: "Responses to the questions from the Public Staff indicated that the results of the analysis were not available for review and that the analysis had not been performed in a number of years." PEC stated that this comment was the result of a misunderstanding and that PEC did provide the requested data. Given the large amount of data the Public Staff had to review, PEC determined that the Public Staff just overlooked it. PEC provided the Public Staff its 2003 and 2007 Reliability Criteria Studies and the Excel files with supporting data used in developing the study reports.

PEC indicated that it conducts its reliability assessments based on maintaining a LOLE of less than one day in ten years. The one day in ten years LOLE criterion is widely accepted within the industry for establishing generation reliability. This type of analysis does not rely on the costs to customers for power outages. To PEC's knowledge, no utility attempts to capture and incorporate consideration of this variable in its reserve margin analyses. This is primarily due to the fact that any attempt to quantify such a variable would be very subjective. Customer outage costs would be extremely difficult to calculate and would require numerous detailed assumptions regarding individual customers' energy use, the value derived by the customer from that energy use, and the economic consequences of interruptions for individual customers. Such a complex and time-consuming hypothetical exercise would be of no value in determining an appropriate reserve margin.

In its reply comments, Duke stated that it does not dispute that it has not recently conducted a formal comprehensive reserve margin study as it has relied primarily upon historical experience to establish its target reserve margin for planning purposes. A 17% target planning reserve margin level has resulted in adequate reserve amounts in the past and has been deemed reasonable by the Commission in the context of prior IRPs filed by the Company. The Company currently deems such level of reserves to be sufficient to cover the foreseeable risk increases resulting from an aging generation system and resource mix with greater amounts of EE, conservation, DSM, and renewable resources. Duke maintained that, with historical reserves dropping to less than 2% of the peak load within the last five years, a 17% target reserve margin is appropriate. As such, Duke stated that it does not believe that a comprehensive study is required at this time. However, if the Commission believes a comprehensive reserve margin study is necessary, Duke would respectfully request that the Commission order the study be conducted for purposes of the Company's next biennial IRP filing in 2012 due to the fact that the 2011 IRP work will likely be substantially complete prior to an order on the 2010 IRP. In addition, given the proposed merger between the holding companies of Duke and PEC, it makes sense to consider the impact of the merger on the individual and joint reserve margin requirements of the two companies. The proposed merger will still be pending approval before various regulatory agencies at the time of the 2011 IRP filing, and the relevant state and federal regulatory approvals of the proposed joint dispatch arrangement between the operating companies will directly impact resource planning for both companies.

Conclusions

In general, the Commission finds the PEC and Duke responses to the Public Staff's request for a comprehensive study to be reasonable and adequate. However, the Commission is of the opinion that it is appropriate for PEC and Duke to perform an updated comprehensive reserve margin study. Therefore, the Commission directs PEC and Duke to prepare a comprehensive reserve margin requirements study and include it as part of its 2012 biennial IRP report. The Commission also directs Duke and PEC to keep the Public Staff updated as they develop the parameters of the studies.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 14

As it did in its testimony in Docket No. E-100, Sub 124, in regard to the IOUs, the Public Staff encouraged the utilization of DSM resources to achieve fuel savings during periods when the price of energy available for spot purchases is high. It is not evident to the Public Staff that in their IRPs the IOUs have fully considered the use of their DSM resources to achieve fuel savings. The Public Staff recommended that the Commission require both the IOUs and EMCs to investigate this use of their DSM resources and include a discussion of the results of their investigations in their next IRPs.

PEC was aware of the Public Staff's position on this issue and has been investigating the use of its DSM programs to reduce its fuel costs.

In its proposed order, Duke noted that the Public Staff is aware that Duke is continuing to investigate the feasibility of using its DSM resources for fuel savings.

Conclusions

The Commission does not see the correlation between fuel savings and the spot market, as such. The Commission does see the value of possibly activating 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 indeed less expensive to activate DSM resources. The Commission expects IOUs and EMCs to use DSM resources, where available, if such resources are less expensive than spot purchases. The Commission directs each IOU and EMC to address this issue, as a specific item, in their 2012 biennial IRP reports.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The Public Staff encourages each IOU and EMC to investigate, develop, and implement all available cost-effective DSM/EE. Changes being proposed to building codes and appliance standards, as well as federal legislation regarding lighting, will substantially impact the ability to implement cost-effective DSM and EE. These changes will have a profound impact on markets for products that consume electricity and may make reliance on older market potential studies unreliable. Therefore, the Public Staff recommended that any IOU or EMC relying on a DSM/EE market potential study older than two years update its study or perform a new study and file it with its next IRP.

PEC agreed that market potential studies should be periodically updated. However, such updates should be prompted by changed circumstances such as changes in building codes and appliance standards rather than simply the passage of time. PEC's Market Potential study, published in March 2009, incorporated projected Energy Independence and Security Act impacts, including new federal lighting standards. PEC stated that it is unclear whether the Public Staff is recommending that IOUs and EMCs should update their market potential studies every two years going forward, or rather, whether the Public Staff is recommending this specific action during this proceeding based on the recent historical developments outlined in their comments.

Duke also agreed with the Public Staff's assessment regarding older market potential studies and believes that an updated or new DSM/EE market potential study is a worthwhile investment of time and money. As Company witness Richard Stevie stated during the evidentiary hearing on the IRPs conducted in Docket No. E-100, Subs 118 and 124, market potential studies should generally be updated every 5 years. Duke stated that it intends to have a new market potential study completed prior to the filing of its IRP in 2012. However, due to the length of time to properly plan, submit for bid, evaluate and complete such a study, it will not be possible for Duke to have its updated market potential study ready for incorporation into its 2011 IRP. Duke stated that it intends to begin the process of designing and requesting bids for this study in early April, 2011. Should the Commission agree with Public Staff's assessment regarding an updated market potential study, the Company respectfully requested that such a study be required for submission with the next biennial IRP, which will be filed on September 1, 2012.

Conclusions

The Commission finds that the responses of PEC and Duke are adequate. PEC's most current study was published in 2009, and PEC appears unsure as to whether the Public Staff is asking for something more. Duke is planning to submit new information with its 2012 biennial IRP report. Since the Public Staff did not comment by way of a proposed order or brief, the Commission finds that no specific action is required at this time. The Commission does, however, direct each IOU and EMC to ensure that the DSM/EE market potential studies on which they rely are updated as necessary to address current legislation and standards.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The Public Staff stated that, while Duke considered scenarios that assumed the impact of enactment of legislation imposing limits on carbon emissions, it did not include a low- or no-carbon scenario in its development of the proposed expansion plans included in its IRP.

The Public Staff further contended that the filings made by NCEMC and the other EMCs did not indicate that their evaluation of resource options considered the effect of potential legislation placing limits on carbon emissions in conjunction with their individual IRPs. The Public Staff recommended that each electric utility be required to include in its 2011 IRP scenarios with no-carbon and low-carbon price impacts, as well as scenarios factoring in the impact of regulation of carbon emissions. These scenarios should also be included in future IRPs submissions until such scenarios are no longer plausible.

Duke explained in its reply comments that responses it gave to Public Staff data requests indicated that an assumption of no- or low-carbon limitations/costs results in the model selecting coal generation facilities. Based on Duke's policy decisions and perception that additional coal generation would be untenable, the Company decided not to include this type of scenario.

PEC responded that, as explained in PEC's 2010 resource plan, its scenario analyses do include a consideration of various carbon emissions reduction requirements.

Conclusions

Only Duke and PEC chose to comment on this issue. The Commission finds the responses of Duke and PEC to be adequate and that no additional specific action by the electric utilities is required at this time. The current scenarios relating to carbon emissions, as provided in the IRPs, are responsive and appropriate for the purposes of this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That this Order shall be adopted as a 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 2010 biennial reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Rutherford, EU, and Haywood are hereby approved.

3. That the 2010 REPS compliance plans filed in this proceeding by the IOUs, GreenCo, Halifax, and EU are hereby approved.

4. That future IRP filings by all utilities 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.

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

6. That future IRP filings by all utilities 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.

7. That French Broad and Blue Ridge shall not be required to file individual IRPs.

8. That all EMCs shall include a full discussion in future biennial IRPs of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

9. That in future biennial IRPs, EU shall provide a more detailed description of the participation and savings related to specific DSM and EE programs, particularly those its proposes to use to meet its REPS obligations.

10. That any EMC which seeks to implement, or is currently implementing, DSM or EE programs under which incentives are offered to customers (except those programs being filed for approval by GreenCo), shall file such programs for Commission approval under G.S. 62-133.9(c) and Commission Rule R8-68 if they were adopted and implemented after August 20, 2007.

11. That if Piedmont determines that its smart meter program is an EE program, it shall file for Commission approval of the program pursuant to Rule R8-68.

12. That each IOU and EMC shall investigate the value of activating 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. This issue shall be addressed as a specific item in their 2012 biennial IRP reports.

13. That PEC and Duke shall prepare a comprehensive reserve margin requirements study and include it as part of its 2012 biennial IRP report. PEC and Duke shall keep the Public Staff updated as they develop the parameters of the studies.

ISSUED BY ORDER OF THE COMMISSION.

This the 26th day of October, 2011.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Deputy Clerk

kh102611.01