STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 118
DOCKET NO. E-100, SUB 124

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Investigation of Integrated Resource Planning in North Carolina – 2008 and 2009	)))	ORDER APPROVING INTEGRATED RESOURCE PLANS AND REPS COMPLIANCE PLANS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on March 15, 16, 17, and 18, 2010

BEFORE: Commissioner William T. Culpepper, III, Presiding; Chairman Edward S. Finley, Jr.; Commissioner Lorinzo L. Joyner; Commissioner Bryan E. Beatty; and Commissioner Susan W. Rabon

APPEARANCES:

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

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

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For CPI USA North Carolina, LLC (CPI USA) and formerly known as EPCOR USA North Carolina, LLC:

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For Haywood, Rutherford, and Piedmont Electric Membership Corporations (EMCs):

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For the North Carolina Sustainable Energy Association (NCSEA):

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For the Southern Environmental Law Center (SELC), Sierra Club, Environmental Defense Fund, and Southern Alliance for Clean Energy (collectively the Environmental Intervenors):

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For the Using and Consuming Public:

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BY THE COMMISSION: General Statute 62-110.1(c) requires the North Carolina Utilities Commission (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 the issuance of a certificate for public convenience and necessity of construction of a generating facility. In addition, G.S. 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of: (1) the Commission's analysis and plan; (2) the Commission's 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 making its analysis and plan pursuant to G.S. 62-110.1.

G.S. 62-2(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 . . . .

S.L. 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended G.S. 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval." G.S. 62-133.9(c).

Senate Bill 3 also specifically defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function." G.S. 62-133.8(a)(2) and (4). EE measures do not include DSM. G.S. 62-133.8(a)(4).

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(3a), the Commission conducts an annual investigation into the electric utilities' integrated resource planning (IRP). IRP is intended to identify those electric resource options which can be obtained at least cost to the ratepayers consistent with adequate, reliable electric service. IRP considers both demand-side options, such as conservation, EE and DSM programs, and supply-side options, including alternative supply-side energy resources, in the selection of resource options.

Commission Rule R8-60 sets out the Commission's requirements for the electric utilities' IRPs and the process for review of such IRPs. The Commission first enacted Rule R8-60 in 1988 and revised it several times thereafter. The Rule was substantially altered by the Commission's Order issued on July 11, 2007, in Docket No. E-100, Sub 111. The 2007 revisions to Rule R8-60 require biennial reports with annual updates in lieu of annual reports, continual assessments by the utilities of programs that promote DSM and EE, an increased amount of information to be provided regarding those assessments, an expansion of the planning horizon from ten to fifteen years, and an accounting in the reports for the effects of demand response (DR) and EE programs and activities. On February 29, 2008, the Commission issued an order in Docket No. E-100, Sub 113, which revised existing Commission Rules and promulgated new rules implementing Senate Bill 3. The Commission further amended Commission Rule R8-60 and promulgated Rule R8-67(b), which directs electric power suppliers subject to Commission Rule R8-60 to file their REPS compliance plans as part of their IRP filings. Commission Rules R8-60 and R8-67 applied prospectively to the 2008 biennial reports. The 2008 biennial reports were the first reports filed pursuant to revised Commission Rule R8-60.

In its March 30, 2009 Order in Docket No. E-7, Sub 858, the Commission ordered Duke to file revisions to its 2008 IRP to address the undesignated load for sales similar to that in the Orangeburg Agreement at issue in that docket and the effects on Duke's future supply and generation requirements. In its November 10, 2009 Order in Docket No. E-7, Sub 923 (Central Order), the Commission ordered Duke to present as part of its 2009 IRP testimony a revised IRP that (1) moved the load associated with the power purchase agreement with Central Electric Power Cooperative, Inc. (Central) out of the undesignated wholesale load amount, (2) contained an explanation of a discrepancy in the Central Order, (3) provided the amount of load and projected load for each wholesale customer on a year-by-year basis through the terms of the current contracts, and explained any growth rates that differ from the projections for retail load, and (4) justified any amount of undesignated load in the revised IRP as to the potential customers' supply arrangements and the reasonable expectations for serving such customers. In its January 28, 2010 Order in Docket No. E-2, Sub 960, the Commission ordered PEC to reflect its additional retirements of coal-fired generation reasonably proportionate to the amount of incremental gas-fired generating capacity authorized by the Lee certificate issued in that docket above 400 MW in its 2010 and subsequent IRPs and to address its progress in retiring its unscrubbed coal units by updates in its annual IRP filings.

Commission Rule R8-60 requires that each of the investor-owned utilities (IOUs), the North Carolina Electric Membership Corporation (NCEMC), and any individual EMC, to the extent that it is responsible for procurement of any or all of its individual power supply resources (hereinafter, collectively, "the utilities"), furnish the Commission with a biennial report in even-numbered years beginning in 2008 that contains its current IRP together with all information required by subsection (i) of Rule R8-60 covering a two-year period. In odd-numbered years, each utility shall file an annual report containing an updated 15-year forecast, supply and demand-side resources expected to satisfy those loads, the reserve margin thus produced, as well as significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable.[1] In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports; (2) include the utility's REPS compliance plan pursuant to Rule R8-67(b); and (3) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p). Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

<u>Procedural History</u>

<u>Docket No. E-100, Sub 118</u>

2008 IRPs were filed by the IOUs, NCEMC, Piedmont EMC (Piedmont), Blue Ridge EMC (Blue Ridge), Rutherford EMC (Rutherford), and EnergyUnited EMC (EU). REPS compliance plans were also filed by the IOUs, as well as GreenCo Solutions, Inc. (GreenCo),[2] Halifax EMC (Halifax), and EU.

On August 18, 2008, GreenCo requested a waiver of the requirement for each of its member EMCs to file individual REPS compliance plans and permission for it to file a consolidated REPS compliance plan on behalf of its member EMCs, with the exception of Halifax, Rutherford, and EU. On the same day, NCEMC, Blue Ridge, Piedmont, and French Broad requested a waiver of the requirement to file individual REPS compliance plans and permission to have GreenCo file a consolidated REPS compliance plan on their behalf. On August 22 and 25, 2008, Duke filed a motion for an extension of time to file its biennial report and REPS compliance plan to November 3, 2008. On

[1] While the 2008 biennial reports and the 2009 annual reports may both be referred to hereinafter as "IRPs" for the respective years, it should be clear from Rule R8-60 that the requirements for a biennial report and an annual report differ.

[2] GreenCo filed a consolidated REPS compliance plan on behalf of Albemarle EMC, Blue Ridge, Brunswick EMC, Cape Hatteras EMC, Craven-Carteret EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC (French Broad), 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.

August 27, 2008, the Commission granted the requests of GreenCo, NCEMC, Blue Ridge, Piedmont, and French Broad for waiver of the requirement that each member EMC file an individual REPS compliance plan and for permission to file a consolidated report, and granted Duke's request for an extension of time to file its biennial report and REPS compliance plan. On August 28, 2008, Rutherford filed a notice with the Commission that its REPS compliance plan would be included in Duke's biennial report and REPS compliance plan. Also, on August 28, 2008, Rutherford filed its biennial report and Halifax filed its REPS compliance plan. On August 29, 2008, DNCP and EU filed their biennial reports and REPS compliance plans. On September 2, 2008, PEC filed its biennial report and REPS compliance plan. On September 12, 2008, NCEMC, Blue Ridge, and Piedmont filed their biennial reports, and NCEMC also filed its Energy Efficiency Potential Study Final Report. On the same day, GreenCo filed the consolidated REPS compliance plan and a motion for a protective order and confidential treatment for information attached to the consolidated report. On September 18, 2008, the Commission granted GreenCo's request for a protective order. On November 3, 2008, Duke filed its biennial report and REPS compliance plan. On January 29, 2009, Fibrowatt LLC (Fibrowatt) filed comments regarding the REPS compliance plans. On March 25, 2009, the Public Staff moved that the deadline for the filing of initial and reply comments on the biennial reports be extended. The Commission allowed the motion on March 30, 2009.

In addition to the Public Staff, the following parties intervened in Docket No. E-100, Sub 118: CIGFUR, NC WARN, Carolina Utility Customers Association, Inc. (CUCA), GreenCo, Fibrowatt, NCSEA, and the Attorney General.

On April 16, 2009, NC WARN filed its initial comments on the biennial reports and a request for an evidentiary hearing. On April 24, 2009, initial comments were filed by NCSEA, which were specifically in regard to the REPS compliance plans. Also, on April 24, 2009, the Public Staff submitted its initial comments. On May 27, 2009, reply comments were filed by the IOUs and the Public Staff. On the same day, NCSEA submitted additional comments.

On July 28, 2009, the Commission issued an Order Denying Request for Evidentiary Hearing, Scheduling Public Hearing, and Requiring Public Notice. This order set the public hearing in the Sub 118 docket for August 31, 2009. On August 12, 2009, NC WARN filed a Motion for Reconsideration and Renewal of Request of Hearing. The public hearing was held as scheduled. Six public witnesses testified in regard to REPS compliance plan issues.

Docket No. E-100, Sub 124

On or about September 1, 2009, the 2009 IRPs, which update the 2008 IRPs, were filed by the IOUs, NCEMC, Piedmont, Rutherford, EU, and Haywood. Blue Ridge had previously entered into a full requirements power purchase agreement with Duke whereby the entire Blue Ridge load is now included in Duke's IRP. Also, on or about September 1, 2009, the 2009 REPS compliance plans were submitted by the IOUs, GreenCo, Halifax, and EU. In addition to the Public Staff, the following parties initially intervened in the 2009 IRP proceeding: CIGFUR, CUCA, NC WARN, Nucor Steel-Hertford, and the Public Works Commission of the City of Fayetteville. The Attorney General filed a Notice of Intervention pursuant to G.S. 62-30.

On October 15, 2009, the Public Staff filed a motion for extension of time until January 15, 2010 for it and other intervenors to file alternative IRPs, annual reports, evaluations of, or comments on the 2009 IRPs.

On October 19, 2009, the Commission issued its Scheduling Order. In the Scheduling Order, the Commission consolidated the 2008 IRPs and the 2009 IRPs, reflecting Commission Rule R8-60 that requires the filing of biennial reports on the IRPs in even-numbered years and the filing of an update to that biennial report in odd-numbered years. The Commission found good cause to schedule an evidentiary hearing for the 2009 IRPs and REPS compliance plans filed by the IOUs. The Commission further directed that the 2009 IRPs filed by the other utilities (the non-IOUs) be addressed through the comment process contained in R8-60(j).

On November 20, 2009, EU filed an updated 2009 IRP. On December 11, 2009, DNCP filed the direct testimony and exhibits of Shannon L. Venable, M. Masood Ahmad, Michael J. Jesensky, and Aaron A. Reed; and PEC filed the direct testimony of David Kent Fonvielle, David Christian Edge, and Glen A. Snider. On January 11, 2010, Duke filed its revised 2009 IRP, the direct testimony and exhibits of Richard G. Stevie, Owen A. Smith, and James A. Riddle, and the testimony of Robert A. McMurry. On January 13, 2010, the Public Staff filed a second motion for extension of time to file comments on the non-IOUs' IRPs and REPS compliance plans, which was allowed by Commission order issued January 14, 2010. On January 29, 2010, CPI USA filed a petition to intervene, which was subsequently allowed. On February 8, 2010, the Public Staff filed comments on the non-IOUs' IRPs and REPS compliance plans. Haywood filed a letter in response to the Public Staff's comments on March 11, 2010.

On February 8, 2010, SELC filed a Petition to Intervene and Motion for Extension of Time to File Testimony. On February 11, 2010, the Environmental Defense Fund, Sierra Club, and Southern Alliance for Clean Energy also jointly filed a Petition to Intervene. On February 11, 2010, the Commission granted SELC's intervention and extended the date for the filing of intervenor testimony to February 19, 2010 and rebuttal testimony to March 9, 2010. On February 16, 2010, the Commission granted the intervention of the Environmental Defense Fund, Sierra Club, and Southern Alliance for Clean Energy.

On February 19, 2010, the Environmental Intervenors filed the testimony and exhibits of David A. Schlissel and John D. Wilson, CPI USA filed the testimony of Don C. Reading, NC WARN filed the testimony and exhibits of John O. Blackburn, and the Public Staff filed the affidavits of Jay B. Lucas, Jack L. Floyd, and Kennie D. Ellis and the testimony of John R. Hinton. On March 9, 2010, Duke filed the rebuttal testimony of Robert A. McMurry and the rebuttal testimony and exhibits of Richard G. Stevie, DNCP filed the affidavit of Shannon L. Venable, and PEC filed the rebuttal testimony of David Christian Edge, David Kent Fonvielle, and Glen A. Snider.

The public hearing regarding the 2009 IRPs and REPS compliance plans began at 7:00 p.m. on March 15, 2010 with ten public witnesses testifying before the Commission as members of the using and consuming public: Michael Thomas Cherin, June Blotnick, Alice Loyd, Elizabeth R. Hutchby, Beth Henry, Miriam Thompson, Bob Rodriquez, Zell McGee, Harry Phillips, and Mary McDowell. The public hearing was reopened at 9:30 a.m. on March 16, 2010, with Ryan William Thompson testifying as a public witness. The public witnesses generally testified in favor of energy conservation and efficiency and renewable energy, especially wind and solar, and against investment in traditional generating facilities. Many of the witnesses brought up the risks of additional coal plants to the health of North Carolina residents and to the environment. The Commission also received five letters and e-mails from customers, generally expressing strong support for energy conservation and renewable energy and urging the Commission to pursue these as integral elements in the utilities' current planning in lieu of fossil-fueled generation.

Following the conclusion of the public hearing, the parties stipulated that the testimony and affidavit of DNCP witness Venable, the testimony and exhibit of DNCP witness Ahmad, and the testimony of DNCP witnesses Jesensky and Reed be entered into the record. PEC presented the direct and rebuttal testimony of David Kent Fonvielle, Director of Fleet Optimization, David Christian Edge, Manager of Retail Market Strategy, and Glen A. Snider, Manager of Resource Planning. Duke presented the direct and rebuttal testimony of Richard G. Stevie, Managing Director of Customer Market Analytics, and Robert A. McMurry, Director of Integrated Resource Planning and the direct testimony of Owen A. Smith, Managing Director of Renewable Strategy and Compliance, and James A. Riddle, Manager of Load Forecasting in the Customer Market Analytics Department. NC WARN presented the direct testimony of John O. Blackburn, Ph.D., Professor Emeritus of Economics, Duke University. The Public Staff presented the testimony of Jack L. Floyd, Kennie D. Ellis, and Jay B. Lucas, engineers with the Electric Division of the Public Staff and John R. Hinton, Financial Analyst with the Economic Research Division of the Public Staff. The Environmental Intervenors presented the testimony of John D. Wilson, Director of Research for the Southern Alliance for Clean Energy, and David A. Schlissel, President of Schlissel Technical Consulting, Inc. CPI USA presented the testimony of Don C. Reading, Vice President and Consulting Economist with Ben Johnson and Associates, Inc.

On June 10, 2010, a brief was filed by NC WARN. On June 11, 2010, briefs were filed by the Environmental Intervenors and CPI USA. Also on June 11, 2010, proposed orders were filed by DNCP, PEC, Duke, and the Public Staff. On June 17, 2010, NC WARN filed a correction to its brief.

Although made shortly after the parties' post-hearing filings, approval of the 2008 IRP filings comes later than otherwise would have been the case due primarily to a change in Commission Rule R8-60 requiring an update to the even-year IRP filings. The next IRP filings will be due on September 1, 2010. With one round of IRP proceedings under new procedural rules behind us, the Commission contemplates that the 2010 filings and the Commission's determination will be timely and in accordance with the schedule and procedure prescribed in Commission Rule R8-60. Accordingly, with respect to future IRP proceedings, all parties are advised that requests for extensions of time will be appropriately scrutinized with an eye toward keeping the proceedings on schedule in order to serve the purposes of the governing statute.

Based upon the foregoing, the information contained in the 2008 biennial reports, the 2009 annual updates to the 2008 biennial reports, the REPS compliance plans, the testimony and exhibits introduced at the hearings, and the Commission's 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 and should be approved.

2. The IOUs' 2008 biennial reports, and the 2009 annual updates to the 2008 biennial reports, are reasonable and should be approved.

3. The IOUs' 2009 REPS compliance plans are reasonable and should be approved.

4. The IOUs should continue to investigate the opportunities to utilize air conditioning cycling load management programs as a way to reduce load and to reduce fuel costs.

5. The 2008 biennial reports, and the 2009 annual updates to the 2008 biennial reports, and 2009 REPS compliance plans submitted by NCEMC, Piedmont, Blue Ridge, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in the testimony of DNCP witnesses Ahmad and Venable, PEC witnesses Snider and Edge, Duke witnesses McMurry, Riddle, and Stevie, NC WARN witness Blackburn, Environmental Intervenor witness Wilson, and Public Staff witnesses Hinton, Ellis, and Floyd, and the 2009 IRPs of DNCP, PEC, and Duke.

DNCP witness Ahmad adopted the portions of DNCP's 2009 IRP dealing with its annual load forecast, as well as its proposed supply-side resources. Chapter 2 of DNCP's 2009 IRP contains its description of methodology for forecasting its peak demand and energy sales needs. DNCP's 15-year forecast from 2010 through 2024 predicted that its summer peaks will grow at an annual average rate of 2.0% after the effects of EE and DSM are included. DNCP's energy sales are predicted to grow at an average annual rate of 2.2% after DSM and EE are included. DNCP is obligated to maintain a reserve margin for its portion of the PJM coincidental peak load, resulting in an effective reserve margin requirement of 12%. Public Staff witness Hinton testified that DNCP's forecasts of peak demand and total energy sales were valid and reasonable for planning purposes.

PEC's 15-year forecast from 2010 through 2024 contained in its 2009 IRP indicates that its system peak loads will grow at an annual average rate of 1.6% after the effects of EE and DSM are included. PEC's energy sales are predicted to grow at an average annual rate of 1.4% after the effects of EE and DSM are included. According to PEC witness Snider, this forecasted growth is comparable to PEC's forecasts in recent years. He also stated that there has been a reduction in the peak load forecast and growth in the near term due to the continuation of the current economic downturn. Mr. Snider further indicated that PEC used the same methods, tools, and models in its 2009 IRP that it employed to develop load and energy forecasts presented to this Commission in prior IRP proceedings in recent years. PEC's 2009 IRP reflects reserve margins of approximately 13% to 26%. Public Staff witness Hinton agreed that PEC's growth rates in the 2009 IRP were similar to those in the 2008 IRP. He further testified that PEC's forecasts of peak demand and total energy sales were reasonable and valid for planning purposes. PEC witness Edge presented testimony regarding PEC's DSM and EE forecasts, as well as its programs and plans. He testified that between 2009 and 2023, PEC forecasts that the projected savings impact for all cost-effective EE will be 3.8% of total retail energy sales.

Duke's 15-year forecast from 2010 through 2024, as reflected in its revised 2009 IRP, predicted that its summer peaks after EE will grow at an annual average rate of 1.8%. Duke's energy sales are predicted to grow at an average annual rate of 1.6% after accounting for the effects of EE. Duke witness McMurry testified that Duke's revised 2009 IRP incorporates a target planning reserve margin of 17%, which Duke's historical experience has shown to be sufficient. Witness Riddle noted that the load forecast portrays the level of expected peak demand prior to any reductions for DSM programs, which are captured and incorporated in the development of the IRP as an offset to the load forecast. Duke witness Stevie noted that after the inclusion of the EE programs, retail sales projected for 2014 are actually below the level for 2009.

Pursuant to the Central Order, Duke's revised 2009 IRP moved the Central wholesale load from undesignated load, provided the amount of load and projected load for each wholesale customer and an explanation for a discrepancy between the growth rates between the wholesale loads and Duke's retail loads, and provided a justification for any amount of undesignated load and the reasonable expectations for serving such customers. Duke witness Riddle testified that he projects slightly less than 1% growth attributable to retail customers with EE and 1.3% without EE, and slightly more than 3.5% to 4% growth attributable to wholesale customers over the 15-year period. Mr. Riddle in his direct testimony addressed possible reasons for the differences in the demand of Duke's wholesale customers as opposed to its retail customers. He pointed out that, in general, wholesale customers' usage is concentrated more with residential and commercial end users with comparatively less industrial usage, as compared to Duke's retail usage, which is more widely distributed among the industrial, commercial, and residential classes. Mr. Riddle stated that because of these characteristic differences, different growth rates are to be expected. He also pointed out that the Central contract provides for a seven year step-in to the customer's full load requirement, with Duke providing 15% of Central's total member cooperative load in 2013, followed by 15% annual increases in load over the subsequent six years until all of the contract load is met.

Duke witness McMurry testified regarding the inclusion of the Central load as a firm requirement and the undesignated load associated with wholesale customers Duke believes it has a reasonable expectation to serve. He was questioned as to the analysis Duke uses to determine whether it has a "reasonable expectation" of serving a customer. Mr. McMurry testified that Duke used an estimate based on whether it believed it had more than a 50% chance of serving a particular customer within the foreseeable future. While Mr. McMurry could not provide an exact answer as to how Duke defined the "foreseeable future," he stated that if it did not appear that a contract would begin in the next two years, Duke should not include that customer in its current IRP. Mr. McMurry said that in such a case, Duke should include the contract in the following IRP if Duke had a reasonable expectation of serving that customer. Mr. McMurry agreed that each wholesale contract differed as to its individual facts and circumstances and that this analysis of whether Duke had a "reasonable expectation" of serving a particular wholesale customer involved a certain amount of subjectivity. He testified that both the inclusion of the Central load and the specified undesignated wholesale load associated with customers whom Duke has a reasonable expectation to serve increased the need for combustion turbine generation in the 2017 and 2026 timeframe.

Public Staff witness Ellis noted that Duke's 2009 IRP filed September 1, 2009, maintained a reserve margin averaging 18.8% throughout the planning horizon, while its revised 2009 IRP incorporated undesignated wholesale load and some changes to the capacity addition schedule, resulting in a reserve margin averaging 19.1% through the planning horizon. Public Staff witness Hinton testified that before inclusion of Duke's wholesale loads, the growth rate of Duke's summer peak demand from 2010 through 2024 is 1.2%, and the growth rate for total energy sales is 1.1%, which is similar to the growth rates in Duke's 2008 IRP. He further testified that the addition of the Central wholesale load and the undesignated load increases the growth rate of the summer peak demand to 1.8% and the growth rate of its total energy sales to 1.6%. Mr. Hinton testified that he found Duke's forecasts of peak demand and total energy sales to be valid and reasonable for planning purposes.

Duke witness McMurry testified that Duke's load forecast was updated to account for the projected load impacts for EE and demand-side resources associated with the settlement in Docket No. E-7, Sub 831 (save-a-watt). Duke witness Stevie testified that the conservation impacts were assumed at 85% of the target impacts from the terms of the save-a-watt settlement (Base Case). Dr. Stevie further testified that the projected load impacts from the conservation programs were based upon three bundles of the portfolio of programs with a new bundle entering every four years. The projected load impacts from Duke's DSM programs are based upon continuing and new DR programs. Dr. Stevie explained that the projection of EE impacts in the 2009 IRP differed in several respects from the 2008 projection: the start of the programs was delayed to the middle of 2009, the EE impacts were scaled up in the third and fourth years consistent with the save-a-watt settlement, and new information on the load shape associated with hourly load savings from the installation of compact fluorescent light bulbs was incorporated into the projection of the coincident peak load impacts. Dr. Stevie explained that the load forecasts prepared by Duke witness Riddle capture the effects of EE trends and activities, including EE resulting from rising fuel prices that occur outside of the Company's own EE programs. Dr. Stevie testified that under Duke's Base Case, which was scaled down to 85% of the projected impacts from the save-a-watt settlement, it projected that by 2020 it would have cumulative energy savings of 4.5% to 5%, or 7% if the effect of increasing energy prices is included. Under Duke's High Case scenario,[3] Dr. Stevie testified that Duke projects a 13.5% decrease in retail sales as a result of EE and DSM by 2029. However, Dr. Stevie testified that although Duke is committed to pursuing all cost-effective EE, he believes achieving the savings target in its High Case would be quite a "stretch." Duke witness McMurry indicated on cross examination that it was too early to tell whether Duke would be able to meet the EE goal to which it had agreed in the save-a-watt docket. He pointed to the number of industrial and commercial customers opting out, as well as a weak adoption rate as potential causes for Duke to miss the goal. He stated that Duke was making its best efforts, but that success in reaching the goal was also contingent on the availability of cost-effective EE.

Public Staff witness Floyd noted that the 2009 IRPs of Duke, PEC, and DNCP included slightly lower impacts from DSM and EE resources than their 2008 IRPs. He opined that this difference is the result of delays in implementation of DSM and

[3] The High Case scenario uses 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 annually until the load impacts reach the economic potential identified by the 2007 market potential study.

EE programs due to current economic conditions, as well as delays in the timing of development, approval, and rollout of the various programs within each portfolio.

NC WARN witness Blackburn testified that the forecasts of PEC and Duke overstated the demand for electricity. Dr. Blackburn produced a plan in which he deducted new wholesale contracts that he deemed unnecessary and recommended an annual EE goal of 1.5%. Dr. Blackburn did not intend that the utilities adopt an annual EE goal of 1.5% for their utility-administered programs, rather he believes that this amount of annual EE savings is achievable in North Carolina during the planning horizon through a combination of utility-sponsored programs, revised building codes, and governmental, individual, and corporate initiatives. In fact, Dr. Blackburn stated that if there were changes in building codes and local, state and federal standards, issuance of executive orders, and governmental initiatives increasing EE, there might be little left for the utilities to do.

Duke witness Stevie questioned the studies on which Dr. Blackburn relied to arrive at his recommendation of a 1.5% annual savings goal for EE. He cited a January 2009 study by the Electric Power Research Institute that implied a reasonable annual savings recommendation of approximately 0.6%. Dr. Stevie pointed out that 8% of Duke's total retail load from the commercial and industrial sector had chosen to opt-out from participation in Duke's EE programs. Duke witness McMurry pointed out that Dr. Blackburn's proposed plan had removed the wholesale contract to supply the load of Central, a wholesale customer that had been historically served by Duke. He also pointed out that Dr. Blackburn's analysis did not provide for any reserve margin and did not contain any detailed cost analysis. PEC witness Edge questioned the American Council for an Energy-Efficient Economy (ACEEE) study cited by Dr. Blackburn, in that it did not take into consideration the opt-out provision available to commercial and industrial customers in North Carolina, which represents 40% of PEC's retail sales. He also pointed out that the ACEEE study reported projected savings in terms of gross savings, while PEC's savings projections are based on net savings. Mr. Edge testified that he believed that it would be inconceivable for PEC to have a goal of 1% annual energy savings over the planning horizon based on PEC's analysis of cost-effective potential EE based under the screening of the total resources cost test.

Environmental Intervenor witness Wilson testified that for 2010, the utilities forecast reducing system sales by 0.3% through EE programs, which he termed a "good start." Mr. Wilson calculates cumulative energy savings from the utilities of 3.1% over the next 15 years. He recommended an annual goal of 1% with projected savings of up to 15% by 2024 for the utilities. PEC witness Edge testified on rebuttal that he disagreed with Mr. Wilson's contention that PEC should have a goal of achieving savings from EE of 15% by 2024. Mr. Edge criticized the studies on which Mr. Wilson relied in that none were specific to PEC's service area, some only projected economic potential, some did not consider the effects of "free riders,"[4] some were regional while others were national

[4] "Free riders" are generally described in the testimony as customers who undertake EE measures on their own initiative, without the influence of utility participant incentives. PEC witness Edge indicated that the energy savings resulting from free riders are not reflected in PEC's projections of energy savings.

in scope, some were meta-analyses of other studies, some relied on implementation of policies beyond those utility-implemented programs, and none took into account the opt-out provision of Senate Bill 3. Mr. Edge testified that both the 15% target by 2024 advocated by Mr. Wilson and the 1.5% annual target advocated by Dr. Blackburn were overly optimistic as they failed to account for the opt-out provision of Senate Bill 3 or new governmental efforts to stimulate EE that reduce the savings potentials for utility-administered programs. Mr. Edge testified that PEC should not rely on the aspirational goals proposed by Dr. Blackburn or Mr. Wilson, but rather on its own comprehensive analysis of available EE and DSM potential in its service territory and its experience implementing and evaluating its programs. Mr. Edge testified that comparison with the EE achievements in states such as Vermont, California, and New Jersey was unfair when numbers from those states' programs reflected achievements prior to the enactment of the Energy Independence and Security Act (EISA), which banned continued used of incandescent light bulbs. The numbers from those programs also do not account for free riders. Mr. Edge testified that in 2007, PEC committed to defer 1000 MW of generation through DSM and EE and that PEC projects a savings of 3.8% through EE and DSM by 2023. PEC witness Snider pointed out that supply-side resources differed from demand-side resources in that a planner could anticipate the quantity of the supply-side resources with greater certainty than with demand-side resources. He testified that this lack of certainty regarding demand-side resources translates into concerns regarding reliability and risk when forecasting DSM and EE.

DNCP witness Venable disagreed with Mr. Wilson's suggestion that the IOUs should meet an annual energy savings goal of 1%, as that target exceeds the requirements of Senate Bill 3. Nonetheless, Ms. Venable testified that DNCP is committed to pursuing EE that is cost-effective and appropriate for its customers.

In making his recommendation of an annual goal of 1% with projected savings of up to 15% by 2024 for the utilities, Environmental Intervenor witness Wilson pointed to states with lower or comparable electricity rates that had achieved much higher rates of EE savings. Duke witness Stevie disagreed with Mr. Wilson's contention that there was little correlation between electricity prices and EE savings and sponsored a rebuttal exhibit showing what he termed "a direct and significant relationship" between the price of electricity and the percent annual incremental EE achievement. Dr. Stevie further testified that it is easier to find cost-effective EE when rates are higher than when they are lower. PEC witness Edge also disagreed with Mr. Wilson's analysis of the correlation between electricity prices and EE. Mr. Edge pointed out that the 2009 ACEEE study cited by Mr. Wilson acknowledges that the highest EE cost savings have been achieved in states with high electricity rates. Mr. Edge also pointed out that there was a correlation between the level of electricity prices and the number of cost-effective EE programs and measures in a state.

Based on the foregoing, the Commission concludes that the energy and peak load forecasts of the IOUs are reasonable and appropriate. The IOUs' forecasting methodology is well accepted in the industry and has proven over time to be reasonably accurate. While the EE savings goals suggested by Dr. Blackburn and

Mr. Wilson may seem attractive, they fail to take into account the opt-out provision of Senate Bill 3, which allows a significant portion of the potential market for savings from EE to decline participation in the utilities' programs. Moreover, the utilities' post-Senate Bill 3 programs are in their early stages and have not been rolled out as quickly as anticipated due to various reasons enumerated above by both utility and Public Staff witnesses. As such, the projections of EE and DSM savings forecasted by the IOUs are found to be reasonable within this proceeding for planning purposes. This should not be regarded as any indication of low expectations for EE and DSM savings on the part of the Commission. These projections are subject to review and re-evaluation in future IRP proceedings and should not be regarded as static. These projections very well could change as the utilities' EE and DSM programs mature and are subject to measurement and verification, and as opportunities for refining existing programs or creating new programs appear on the horizon.

In regard to the appropriate treatment of wholesale load, the Commission finds that in future IRPs, all utilities should be required 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. Further, the approval of any IRP that includes undesignated load should not be cited as advance approval of any wholesale contract or method of cost allocation associated with any wholesale contract in a future proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting this finding of fact is contained in the testimony of DNCP witnesses Jesensky and Venable, PEC witness Snider, Duke witnesses McMurry, Riddle, and Stevie, NC WARN witness Blackburn, Environmental Intervenor witnesses Wilson and Schlissel, and Public Staff witness Ellis, and the 2008 and 2009 IRPs of DNCP, PEC, and Duke.

DNCP witness Venable presented testimony regarding the utility's 2009 IRP, including an overview of the IRP process and a discussion of the Company's plans for future REPS filings. She noted in her direct testimony that DNCP's 2009 IRP included provisions to achieve policy goals from individual state legislatures. DNCP witness Jesensky discussed the utility's current, proposed, and future DSM programs. DNCP's IRP indicates that it has not filed for approval of DSM programs in North Carolina, but plans to implement a portfolio of DSM programs in Virginia after the Virginia State Corporation Commission approves them, and will evaluate and consider these programs for approval and implementation in North Carolina.[5] Environmental

[5] The Commission notes that in Docket No. E-22, Sub 418, on March 11, 2010, DNCP was ordered to file for approval appropriate demand response (DR) programs for its North Carolina customers by September 1, 2010.

Intervenor witness Wilson recommended that DNCP file its proposed EE programs in North Carolina as expeditiously as possible and recommended that all the utilities participate in a regional EE database and collaboration process. According to DNCP witness Venable, while DNCP does not support the creation of a regional EE database and collaboration process, it does support an inclusive stakeholder process.

PEC witness Snider testified that he oversaw the development of PEC's 2009 IRP. According to Mr. Snider, with regard to new supply resources, the only resources PEC is committed to install are the combined-cycle generation facilities at PEC's Richmond County and Wayne County sites. He stated that all other generation additions shown in PEC's plan are generic resources indicating the need for additional generation. According to Mr. Snider, PEC has made no commitments to any specific type, amount, location, or ownership of the needed capacity.

Duke witness McMurry testified that he oversees long-term resource planning for Duke. According to Mr. McMurry, based on the results of the 2009 IRP, the assumed retirement dates of Duke's older fleet of combustion turbines at Buck Steam Station, Dan River Steam Station, Riverbend Steam Station and Buzzard Roost Combustion Turbine Station were accelerated from the 2014-2015 timeframe to June 2012, and the remaining coal units without scrubbers at Buck Steam Station Units 5 and 6 and Lee Steam Station Units 1 through 3 were assumed to be retired in 2020 based on expected increased regulatory scrutiny. He stated that these planned retirements total an additional 625 MW of retired generation in the 2009 IRP as opposed to the 2008 IRP. Mr. McMurry testified that due to the impact of the recession on load growth, the combustion turbine portion of the new Buck combined cycle plant will not be operable during the summer of 2011, and the need for the new Dan River combined cycle plant has been delayed until the summer of 2013. Based on Duke's analysis, it determined that the addition of the Central load increases the need for combustion turbine generation in the 2017 and 2026 timeframe and supports the need for nuclear generation in the 2018 to 2021 timeframe. Mr. McMurry testified that the nuclear project cost escalation rate was also reduced from the 2008 to 2009 IRP. He stated that even with the inclusion of the updated information for the revised 2009 IRP, the basic conclusions of the 2008 IRP are unchanged.

NC WARN witness Blackburn testified that, in his opinion, substantially all of Duke's and PEC's coal plants could be phased out within the planning period without the addition of new nuclear generation if the following goals were achieved: (1) an annual EE goal of 1.5% over the planning period, (2) a renewable energy goal of 20%, and (3) a customer cogeneration or combined heat and power (CHP) goal that amounts to 16-17% of total power generation in North and South Carolina. Dr. Blackburn noted that in his plan, existing hydroelectric power would be allowed to count toward the renewable energy target. Dr. Blackburn conceded on cross-examination that his plan did not include any reserves and that additional costs for transmission, grid stability, and voltage control would be incurred if the renewable resources envisioned under his plan were added to the grid. Dr. Blackburn also agreed that implementation of his plan could require changes in laws and policies beyond the purview of the Commission.

Dr. Blackburn testified about a study he performed regarding how wind and solar might offset each other when operated in tandem despite their intermittent nature. His study showed that while the stream of electricity from the two sources still fluctuated when operated in tandem, it was much more stable. He concluded that while intermittency is a problem, it is manageable. On cross-examination, Dr. Blackburn admitted that he had matched loads on an hourly basis, rather than on a second or minute basis. He further conceded that of the 123 days of his study, there were three days when there was an inadequate supply of electricity and 17 hours when there was a need for back-up generation. The study also assumed from the onset that consumption was reduced by 20% due to EE.

Duke witness McMurry testified on rebuttal that history indicated that it was not economically feasible for customers to build CHP facilities on a large scale, and that he deemed Dr. Blackburn's CHP goal unrealistic. Mr. McMurry found Dr. Blackburn's plan to be flawed, and declared it to be a plan that would result in both higher costs and less reliability, contrary to the goals of IRP. Mr. McMurry referred to Dr. Blackburn's proposal as a "vision plan" as opposed to a resource plan.

Environmental Intervenor witness Schlissel testified that Duke's emissions from carbon will increase in each of its resource portfolios between 2010 and 2029 despite its plan to retire 1,600 to 1,700 MW of cycling coal units by 2020 as a result of the addition of Cliffside Unit 6. He also advocated that Duke and PEC consider the regulation of coal combustion products (CCPs) in their IRPs. Mr. Schlissel recommended that Duke use a wider range of carbon prices and testified that the methodology PEC used to make its assumptions regarding carbon prices was inadequate. He stated that if Duke were to build more natural gas fired generation, it would diversify Duke's portfolio and lower its emissions, especially since natural gas has been forecasted to have a greater supply and a lower price than had been previously thought. Mr. Schlissel pointed out that PEC mentions potential regulation of coal combustion waste as a significant challenge, but that Duke's IRP does not address the issue. He criticized Duke and PEC for not sufficiently reflecting the current and upcoming regulatory challenges surrounding air emissions. Mr. Schlissel recommended that the Commission require the utilities to include a detailed discussion and analysis of pollution control standards and to show how these are factored into their IRPs.

Duke witnesses McMurry and Riddle testified that one major difference between Duke's 2008 and 2009 IRPs was that Duke began incorporating the expected impact of greenhouse gas regulation into its load forecast in its 2009 IRP. However, Duke did consider the impact of carbon legislation in its 2008 IRP in its Higher Carbon Case analysis. Duke witness McMurry testified on rebuttal that as a result of its planned retirements and additions, including Cliffside 6, Duke's CO_2/MWh emissions will decline by 30% by 2029. He also pointed out that adding natural gas-fired plants would not significantly alter the dispatch order for generation and therefore not significantly impact Duke's CO_2 emissions. Mr. McMurry further testified that even with lower natural gas prices, Duke's analysis indicates that it would not be cost-effective to retire other coal-fired plants and replace them with natural-gas-fired plants. He testified that while not explicit in its IRP, Duke's analysis did consider the regulation of coal ash and its by-products. While Mr. McMurry did not agree with Mr. Schlissel that Duke should have used a wider range of potential carbon prices in its 2009 IRP based on the circumstances at that time, he stated that Duke may consider using a wider range in its 2010 IRP.

PEC witness Snider testified that PEC's plan reflects acknowledgment of the widely accepted assumption that there will be environmental legislation in the future requiring review of continued operation of certain coal-fired generation. This potential environmental legislation includes a carbon tax, the Clean Air Interstate Rule, maximum achievable control technology requirements in the wake of the vacatur of the Clean Air Mercury Rule, revision of the National Ambient Air Quality Standards for ground-level ozone, regulation of CCPs, and other laws or rules dealing with global climate change. According to Mr. Snider, as the 2009 IRP was an update to the 2008 IRP, PEC factored these legislative changes into its cost assumptions, but did not run different sensitivities when performing its IRP modeling in 2009.

Environmental Intervenor witness Wilson testified that the IOUs still treat EE as a second-class resource by failing to consider demand-side resources on an equivalent basis with supply-side resources. He noted that while all of the IOUs described their various EE or DSM programs in their 2009 IRPs, they did not describe the capacity, energy, number of customers and other required information for each program over the 15-year period. Mr. Wilson pointed out that this descriptive data was important for the Commission to analyze whether demand-side resources were being considered on an equal footing with supply-side resources. He further testified that both Duke's Base Case and its High Case appear to have been developed in a manner that does not reflect the program design principles and intent of the approved programs, in that they understate the probable impact of Duke's EE programs. Mr. Wilson recommended that Duke revise its resource plan to reflect a consistent trend in EE program growth consistent with available EE potential and opportunities for reasonable program growth. He also found certain information in PEC's IRP regarding the capacity and energy impacts of its demand-side resource forecast to be inconsistent or confusing. Mr. Wilson contended that neither Duke nor PEC performed a comprehensive analysis of demand-side resources in their 2009 IRPs. He recommended that the utilities either perform an EE potential study that captures all possible EE measures or set an annual energy savings goal that is benchmarked against leading efforts across the country. Mr. Wilson suggested that the Commission require the utilities in their resource planning to provide a more detailed explanation of how they selected their preferred portfolios, consider risks that cause short-term rate spikes, and create a regional EE database and collaboration process.

Duke witness Stevie disagreed with Mr. Wilson's contention that Duke relegated EE to a second-class status. Dr. Stevie explained that Duke evaluates demand and supply-side resources in a portfolio modeling exercise by having them compete with each other in an optimization model. While Dr. Stevie agreed with Mr. Wilson that Duke should have described the capacity, energy, number of customers and other required information for each EE or DSM program over the 15-year period, he disagreed with Mr. Wilson's charge that Duke had not included a comprehensive analysis of EE measures in its IRP. Dr. Stevie testified on rebuttal that Duke had already engaged in a bottom-up approach to study the economic potential of EE as advocated by Mr. Wilson. Dr. Stevie agreed with Mr. Wilson's statement that neither an EE potential study nor industry experience can provide as precise measure of cost-effective EE as a supply-side generation plan that can anticipate generation capacity. Dr. Stevie pointed out that there is greater uncertainty associated with the implementation of EE programs that can only be resolved as experience is gained with the newly implemented programs. He testified that as Duke had an ongoing collaborative process, there was not a need for a regional collaborative as suggested by Mr. Wilson. However, Dr. Stevie agreed with Mr. Wilson that a regional database should be created and kept up to date. Dr. Stevie testified that Duke should update its market potential study at least every five years, thus the 2007 study should be updated by at least 2012.

PEC witness Snider noted in his rebuttal testimony that PEC had assumed in IRPs prior to 2009 that all longer term power purchase agreements (PPAs) were perpetually renewed. PEC's 2008 IRP lists six wholesale PPAs with four entities that were assumed to be renewed following the expiration of the contracts. Beginning with the 2009 IRP, PEC assumed that such PPAs would expire at the end of their current terms. Mr. Snider listed several factors in support of this change. PEC has the right to purchase capacity only for the duration of the existing contract. At the expiration of the contract, the owner might elect to sell the capacity and energy to another purchaser, the facility might not be capable of providing reliable power to PEC, the owner might not have the financial ability to support a future agreement, or PEC might determine that the resource is not optimal for a variety of reasons. In the case of a facility producing renewable energy, the viability of the facility may be affected by external factors such as tax credits, steam hosts, renewable status, and environmental compliance.

Public Staff witness Ellis testified that the discussions of generating facilities, reserve margin adequacy, non-utility generation, wholesale power contracts, transmission facilities, transmission planning, evaluation of resource options, and levelized busbar costs in the 2009 IRPs of DNCP, PEC, and Duke, which were updates to the 2008 biennial reports, appeared to meet the requirements of R8-60.

Rule R8-60(h) requires that annual reports, such as the 2009 IRPs, contain an updated 15-year forecast of native load requirements and other system capacity or firm energy obligations; supply-side and demand-side resources expected to satisfy those loads; the reserve margin thus produced; significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable; a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate; and the utility's REPS compliance plan pursuant to Rule R8-67(b). Unless there have been significant amendments or revisions to the biennial plan, the utility in an annual report is not required to perform the comprehensive analysis of all resource options pursuant to Rule R8-60(c)(2), nor to provide the items required by Rule R8-60(d), (e), (f), and (g). Utilities may certainly provide this information on a voluntary basis. This was the first year that the utilities filed annual IRP reports pursuant to the revised Rule R8-60, and it appears that there was confusion regarding the difference in requirements for a biennial report and an annual report. In order to reduce such confusion, the Commission will require the inclusion in future annual reports of an introduction in which the utilities list any circumstances which necessitate significant amendments or revisions to the most recently filed biennial reports and specify the portions of such biennial reports that have been amended or revised.[6]

Because the 2009 IRPs were annual reports as opposed to biennial reports, the utilities were not required to perform the same level of analysis as required for a biennial report unless there had been significant changes or revisions. It appears that to some extent, both PEC and Duke took into account the changes in environmental regulation occurring in the interval between their 2008 and 2009 IRPs. The regulatory climate surrounding climate change, CCPs, and other environmental issues certainly changed from the filing of the 2009 IRPs in September 2009 to the time of the hearing in March 2010, and the Commission expects that it will have changed by the time the 2010 IRPs are filed in September 2010. The biennial reports are to contain all required information, full and robust analyses and sensitivities, which should encompass a range of scenarios including potential regulatory changes.

While it should be clear at this point, the Commission reiterates that inclusion of a DSM or EE program, a proposed new generating station, a proposed new transmission line, or a purchased power contract in a utility's IRP filing does not constitute approval of any of those aspects of the plan even if the IRP as a whole is approved.

Based on the foregoing, the Commission's review of the 2009 annual updates and the 2008 biennial plans, and the entire record of this proceeding, the Commission concludes that the 2008 and 2009 IRPs submitted by the IOUs are reasonable for purposes of this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence supporting this finding of fact is contained in the testimony of Duke witness Smith, DNCP witnesses Reed and Venable, PEC witness Fonvielle, CPI USA witness Reading, and Public Staff witnesses Lucas and Ellis, and the 2009 REPS compliance plans of DNCP, PEC, and Duke.

Duke witness Smith testified that under G.S. 62-133.8(b)(1), each utility in the State must comply with the REPS requirement in accordance with a statutorily set schedule based upon 3% of the utility's North Carolina retail sales beginning in the year 2012, 6% in 2015, 10% in 2018 and 12.5% in 2021 and thereafter. Additionally, G.S. 62-133.8(d) requires that each utility satisfy its REPS requirement with solar energy based upon 0.02% of the utility's North Carolina retail sales beginning in the

[6] This does not apply to the information required to be filed annually pursuant to Rule R8-60(c)(1).

year 2010, 0.07% in 2012, 0.14% in 2015, and 0.20% in 2018 and thereafter. In its Order Clarifying Electric Power Suppliers' Annual REPS Requirements, issued on November 26, 2008, in Docket No. E-100, Sub 113, the Commission clarified that the calculation of these requirements for each year would be based upon the utility's North Carolina retail sales for the prior year. Additionally, the Commission has clarified that the swine and poultry waste set-aside requirements of G.S. 62-133.8(e) and (f) are aggregate obligations of the utilities. Mr. Smith testified that upon the passage of Senate Bill 3, Duke modified its consideration of renewable energy resources. Instead of screening such resources based on their economics, initial consideration is given to the level of renewable resources necessary for compliance with G.S. 62-133.8 and the Commission's rules. Public Staff witness Lucas testified that he believed that Duke should be able to meet its REPS requirements for the period covered by its plan, 2009-2011.

DNCP witness Reed presented testimony regarding the Company's 2009 REPS compliance plan filed with its 2009 IRP. Ms. Venable testified that the Company has been having difficulty obtaining poultry and swine renewable energy resources, but has been cooperating with the other IOUs in Docket No. E-100, Sub 113, to develop a solution. Public Staff witness Lucas testified that he believed that DNCP should be able to meet its REPS requirements for the period covered by its plan, 2009-2011.

PEC witness Fonvielle testified that based on experience to date and current assumptions, PEC's REPS plan is projected to achieve compliance with the REPS requirements. However, he noted that there are significant uncertainties that could adversely impact PEC's ability to meet the long-term REPS requirements. These uncertainties include undesignated future resources that may not materialize, as well as changes in the cost or availability of resources, especially set-aside resources. Mr. Fonvielle noted that since the filing of its 2009 REPS compliance plan, PEC had resolved issues involving its poultry waste set-aside and that it was actively pursuing meeting that requirement for 2012. Mr. Fonvielle testified that PEC's 2009 REPS compliance plan indicates that based on its projected requirements, EE, and contracted resources, PEC has enough resources to achieve compliance through 2013 and needs a minimum of an additional 170 gigawatt-hours to be in compliance in 2014. However, Mr. Fonvielle testified that based on current prices, the chances of PEC being able to reach Senate Bill 3's 12.5% goal in 2021 without reaching the price cap imposed by G.S. 62-133.8(h)(3) and (4) were not "so great" in the long term, though PEC's chances of meeting the goals in the early and mid-term were more favorable. He also stated that PEC was in good shape to meet its REPS goals through 2018 based on current expectations. Mr. Fonvielle expressed his hope that the development of a more competitive market would drive prices down and make the goals more achievable in the long term. Public Staff witness Lucas testified that he believed that PEC should be able to meet its REPS requirements for the 2009-2011 period covered by its plan.

Public Staff witness Ellis testified that unless the price of RECs drops considerably, meeting the REPS requirements beyond the short term could become challenging, as the IOUs may reach the caps in the near future. Mr. Ellis pointed out the fact that under Senate Bill 3, the cost caps do not rise as quickly as the REPS requirements. According to Mr. Ellis, this could create a situation where the utilities reach the cost caps before they meet the REPS goals.

CPI USA witness Reading testified that with the significant lead time required to build new renewable resources, he doubted whether PEC could meet the mandates of Senate Bill 3 in regard to in-state RECs. He pointed to the output of the facilities of CPI USA as a potential source for such in-state RECs, and noted the pending arbitration between his client and PEC over a PPA. Mr. Reading stated that while PEC's 2008 IRP listed cogeneration resources of 179 MW, these resources have been reduced to zero in PEC's 2009 IRP, indicating a less robust and balanced resource plan. Mr. Reading further testified that his calculations indicated that the most readily available resource by which PEC could meet its REPS requirement is biomass. He testified that PEC showed no deficit in renewable resources until 2014, and that PEC would have three years to attain those requirements. CPI USA's specific interest in this issue is the subject of a separate arbitration proceeding before this Commission in Docket No. E-2, Sub 966, and will be addressed by the Commission in that docket.

No party contended that the IOUs' REPS compliance plans for 2009-2011 were insufficient, but there was concern whether the IOUs could meet the REPS mandates through 2021 without reaching the cost caps. The Commission shares this concern and will closely monitor the utilities' compliance plans and their progress toward meeting each of the REPS requirements in the coming years.

The 2009 REPS compliance plans submitted in Docket No. E-100, Sub 124, completely supersede the 2008 REPS compliance plans submitted in Docket No. E-100, Sub 118. Therefore, the Commission has not made any determination as to the acceptability of the 2008 plans.

Based on the foregoing, the Commission's review of the 2009 REPS compliance plans, and the entire record of this proceeding, the Commission concludes that the 2009 REPS compliance plans submitted by the IOUs are reasonable for purposes of this proceeding and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is contained in the testimony of, DNCP witness Venable, PEC witness Snider, and Public Staff witnesses Floyd and Hinton, and the 2009 IRPs of DNCP, PEC, and Duke.

Public Staff witness Floyd testified that the IOUs should utilize their DSM resources to obtain the maximum system value possible. He pointed out that while increased utilization of DSM might not lead to capacity savings, it might result in energy savings, with corresponding fuel savings. Mr. Floyd noted that both Duke and PEC received approval in 2009 for new residential air conditioning cycling programs that provide the capability to control central air conditioning systems in a manner that causes less customer inconvenience than earlier versions of such programs. He encouraged the IOUs to maximize the value of these air conditioning cycling programs. Similarly, Public Staff witness Hinton testified that while increased activation of these cycling programs should not have a material effect on the IOUs' expansion plans, it could allow the IOUs to achieve increased fuel savings during other near-peak or forced outage events. Mr. Hinton also pointed out that increased activation of these cycling programs could be beneficial to the utilities in that it would allow them to gain operational experience, test the program infrastructure, and assess customer response to more frequent power curtailments.

Mr. Floyd testified that he had compared Duke's Power Manager and PEC's EnergyWise air conditioning cycling programs with programs in other states and jurisdictions to some extent. He called PEC's and Duke's programs "new age" in that they involve new technology, but pointed to a program in Maryland that allows the customer to choose a level of incentive based on the amount of air conditioning load control he is willing to cede to the utility. Mr. Floyd deemed programs with various levels of incentives as a potential opportunity for consideration by North Carolina's IOUs.

DNCP witness Venable testified that DNCP included an air conditioner cycling program in its initial DSM portfolio modeled for the 2009 Plan and will consider opportunities for lowering fuel costs once the program is approved in North Carolina and it can further analyze operational data. PEC witness Snider testified that PEC will investigate and evaluate optimal use of its EnergyWise residential air conditioning load control program, including consideration of its potential benefits as a capacity resource and as a tool to lower fuel costs.

The Commission finds that DSM resources should be optimized so as to obtain their maximum value. Accordingly, the IOUs are encouraged in their 2010 IRPs to consider their DSM resources' potential benefits, both as capacity resources and as a means of lowering fuel costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact is contained in the Public Staff's comments filed on February 8, 2010, and the 2008 and 2009 IRP and 2009 REPS compliance plans of NCEMC, Piedmont, Blue Ridge, Rutherford, EU, Haywood, GreenCo, and Halifax.

On February 8, 2010, the Public Staff filed the only comments on the IRPs and REPS compliance plans filed by the non-IOU electric utilities. As part of its comments, the Public Staff addressed the IRPs filed by NCEMC, Piedmont, Rutherford, EU, and Haywood and the REPS compliance plans filed by GreenCo, Halifax, and EU in Docket No. E-100, Sub 124, pursuant to Rule R8-60.

The 2009 IRPs are, as described above, the annual updates to the 2008 IRPs. Therefore, consistent with Rule R8-60(h)(2), the Public Staff's comments addressed the non-IOUs' updated 15 year forecasts and significant amendments or revisions to their 2008 IRPs. The Public Staff's initial comments on the 2008 IRPs, filed April 24, 2009, and its reply comments filed May 27, 2009 (collectively, 2008 Comments), in Docket No. E-100, Sub 118 were incorporated by reference. Overall, the Public Staff found the IRPs and REPS compliance plans to be acceptable.

As noted in its comments, the Public Staff's analysis of NCEMC's peak load forecasting accuracy over the past five years indicates that the forecasts with DSM in its 2004 annual report were, on average, 332 MW lower than the actual system load, a 11% forecast error, whereas, its energy sales forecast has been more accurate with less than a 5% error rate. All of the peak load predictions from the 2004 Annual Plan have been less than the actual peak loads experienced. The Public Staff had noted this pattern of under-forecasting of peak loads in comments filed in previous IRP dockets. Since NCEMC does not weather normalize its peak loads, the Public Staff was unable to examine the accuracy of the forecasts excluding the effects of weather.

As it did in its comments in Docket No. E-100, Sub 118, the Public Staff continues to recommend that NCEMC examine its peak load forecasting models and assumptions for possible sources of bias leading to under-forecasting of peak loads, as well as other factors that may have contributed to the relatively large forecast errors. NCEMC is addressing this concern in two ways. First, it has informed the Public Staff that it intends to use a weather normalization methodology in its 2010 IRP. Second, NCEMC is evaluating other peak demand models. Both of these actions should assist NCEMC in improving its forecasting accuracy.

As noted on page 4 of its IRP, NCEMC completed a forecast in late 2009 that reflected the impact of the 2008/2009 economic recession. The new forecast indicates compound annual growth rates of 1.6% for summer peaks, 1.6% for winter peaks, and 1.3% for energy sales. The peak load forecasts are based on more current information than that available to NCEMC at the time of the filing of its 2009 IRP. The Public Staff believes NCEMC's updated forecast is more accurate in light of current conditions. Due to a lack of historical data, the accuracy of the forecasts of EU, Haywood, Piedmont, and Rutherford were not reviewed.

With the exception of Rutherford, the Public Staff believes the EMCs are developing new DSM/EE programs for their customers. Each EMC has continued to rely on its existing load control resources as its primary DSM/EE resources. The Public Staff was encouraged to see GreenCo develop a portfolio of DSM/EE resources that will be available to each of its participating members.

Based on the Public Staff's comments, and the Commission's review of the record in this proceeding, the Commission finds that the 2008 and 2009 IRPs and 2009 REPS compliance plans of NCEMC, Piedmont, Blue Ridge, Rutherford, EU, Haywood, GreenCo, and Halifax are reasonable and should be approved. The 2009 REPS compliance plans submitted in Docket No. E-100, Sub 124, completely supersede the 2008 REPS compliance plans submitted in Docket No. E-100, Sub 118.

Therefore, the Commission has not made any determination as to the acceptability of the 2008 plans.

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 2008 biennial reports and the 2009 annual updates to the 2008 biennial reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Blue Ridge, Rutherford, EU, and Haywood are hereby approved.

3. That the 2009 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 respective utility's projected reserve margins.

5. That future IRP filings by all utilities shall 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: (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. If time constraints dictate, this information may be filed separately from the main body of the 2010 report.

7. That the IOUs shall continue to investigate increased reliance on air conditioning cycling load control and other DSM resources so as to obtain the maximum value from those resources.

8. That NCEMC shall examine its peak load forecasting models and assumptions for possible sources of bias leading to under-forecasting of peak loads, as well as other factors that may have contributed to the relatively large forecast errors in the past.

9. 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), 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.

ISSUED BY ORDER OF THE COMMISSION.

This the 10th day of August, 2010.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Deputy Clerk