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June 11, 2010

FILED
JUN 11 2010
Clerk's Office
N.C. Utilities Commission

OFFICIAL COPY

Ms. Renne Vance, Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Raleigh, North Carolina 27603-5918

Re: Dockets No. E-100, Sub 118 and E-100, Sub 124
Investigation of Integrated Resource Planning in North Carolina – 2008 and 2009

Dear Ms. Vance:

Please find enclosed for filing in the above captioned docket an original and 30 copies of the Proposed Order of Dominion North Carolina Power pursuant to the Notice of Mailing Transcript issued by the Commission on April 13, 2010, and the Order Granting Extension of Time issued on May 13, 2010, in this proceeding.

Also enclosed is a copy to be file-stamped and returned with our courier. Should you have any questions please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,



Andrea R. Kells

Enclosures

*Full Dist. only
disk to Patricia*

FILED
JUN 11 2010

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 118

**In the Matter of
Investigation of Integrated Resource
Planning in North Carolina – 2008**

DOCKET NO. E-100, SUB 124

**In the Matter of
Investigation of Integrated Resource
Planning in North Carolina – 2009**

PROPOSED ORDER OF DOMINION NORTH CAROLINA POWER

HEARD: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on March 15, 2010 at 7:00 p.m., March 16, 2010 at 9:30 a.m. and 1:30 p.m., March 17, 2010 at 10:30 a.m. and 1:20 p.m., and March 18, 2010 at 1:00 p.m.

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

APPEARANCES:

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

Robert W. Kaylor
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For Duke Energy Carolinas, LLC

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

Len S. Anthony
410 Fayetteville Street
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For the Using and Consuming Public:

Robert S. Gillam
430 N. Salisbury Street
Raleigh, North Carolina 27699-4236

BY THE COMMISSION: G.S. 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 construction. In addition, G.S. 62-110.1 requires the Commission to annually submit to the Governor and the appropriate committees of the General Assembly the following: (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 – North Carolina Utilities Commission (“Public Staff”) to assist the Commission in 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 the 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(3a), the Commission conducts an annual investigation into the electric utilities’ integrated resource planning pursuant to Commission Rule R8-60. Rule R8-60(c) requires that each of the electric utilities develop and keep current an integrated resource plan.

SENATE BILL 3 AND COMMISSION RULES

Senate Bill 3

S.L. 2007-397 (“Senate Bill 3”), which was signed by Governor Easley on August 20, 2007, added subsection (a)(10) to G.S. 62-2(a). Subsection (a)(10) 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 within North Carolina; (3) encourage private investment in renewable energy and energy efficiency (“EE”); and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that

end, Senate Bill 3 further provides that each electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management (“DSM”) and EE in its integrated resource plans submitted to the Commission and shall submit cost-effective DSM and EE options that require incentives to the Commission for approval.¹

Commission Rules

On July 11, 2007, the Commission issued an Order in Docket No. E-100, Sub 111, revising Commission Rules R8-60 and R8-61. Revised Rule R8-60 replaces the requirement for an annual integrated resource plan with a requirement for a biennial integrated resource plan in even-numbered years, containing the information required by Rule R8-60, and annual updates in odd-numbered years that revise their most recently *filed biennial integrated resource plan*.

On February 20, 2008, the Commission issued an Order in Docket No. E-100, Sub 113, which revised the Commission’s existing rules and promulgated new rules implementing Senate Bill 3. Revised Rule R8-60 now requires the electric utilities continually to assess programs that promote DSM and EE, and increases the level of detailed information required for assessment of these programs. The revised Rule also expands the planning horizon from 10 years to 15 years and requires that the reports account for the effects of demand response (“DR”) and EE programs and activities. The 2008 integrated resource plans (“2008 Plans”) were the first reports filed pursuant to revised Commission Rule R8-60.

The utilities’ integrated resource plans must incorporate, at a minimum: (1) a 15-year forecast of native load requirements (including any off-system obligations approved for native load treatment by the Commission) and other system capacity or firm energy

¹ G.S. 62-133.9(c).

obligations extending through at least one summer or winter peak (other system obligations), supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads, and the reserve margin thus produced; and (2) a comprehensive analysis of all resource options (supply- and demand-side) considered by the utility for satisfaction of native load requirements and other system obligations over the planning period, including those resources chosen by the utility to provide reliable electric utility service at least cost over the 15-year planning period. Specifically, Rule R8-60(i) requires the utilities to include the following in their integrated resource plans: (1) forecasts of load; (2) forecasts of supply- and demand-side resources; (3) generating facilities including existing *generation, planned generation additions, and non-utility generation*; (4) *reserve margins*; (5) wholesale contracts for the purchase and sale of power; (6) transmission facilities; (7) demand-side management; (8) assessment of alternative supply-side energy resources; (9) evaluation of resource options; and (10) levelized busbar costs.

In addition, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of its integrated resource plan. Rule R8-60(c) requires that each utility's supply- and demand-side resources, including alternative supply-side energy resources and the provision of reliable electric utility service at least cost, appropriately consider and incorporate the utility's obligation to comply with the REPS. G.S. 62-133.8.

PROCEDURAL HISTORY

Docket No. E-100, Sub 118

Biennial 2008 Plans were filed by 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") (collectively, "the investor-owned utilities"), and by the North Carolina Electric Membership Corporation ("NCEMC") and the four independent electric membership corporations ("EMCs"), i.e., Piedmont EMC ("Piedmont"), Blue Ridge EMC ("Blue Ridge"), Rutherford EMC ("Rutherford"), and EnergyUnited EMC ("EnergyUnited"). REPS compliance plans were filed by PEC, Duke,² DNCP, GreenCo Solutions, Inc. ("GreenCo"),³ Halifax EMC ("Halifax"), and EnergyUnited.

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.⁴ 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 2008 Plan and REPS compliance plan to November 3, 2008. On August 27, 2008, the Commission granted the requests of

² Duke's REPS compliance plan included the REPS compliance plan for Rutherford.

³ GreenCo filed a consolidated REPS compliance plan on behalf of its members: Albemarle EMC, Blue Ridge, Brunswick EMC, Cape Hatteras EMC, Craven-Carteret EMC, Central EMC, Edgecombe-Martin EMC, Four County EMC, French Broad EMC ("French Broad"), Haywood EMC ("Haywood"), Jones-Onslow EMC, Lumbree 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 Power Cooperative, and Wake EMC.

⁴ GreenCo stated that separate filings would be made by EnergyUnited, Halifax, and Rutherford, which are not members.

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 2008 Plan and REPS compliance plan. On August 28, 2008, Rutherford filed its 2008 Plan and Halifax filed its REPS compliance plan. On August 29, 2008, DNCP and EnergyUnited filed their 2008 Plans and REPS compliance plans. On September 12, 2008, NCEMC, Blue Ridge, and Piedmont filed their 2008 Plans 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. On November 3, 2008, Duke filed its 2008 Plan and REPS compliance plan. On March 25, 2008, the Public Staff moved that the deadline for filing of initial and reply comments on the 2008 Plans be extended. The Commission granted the requested extension of time by order issued March 30, 2009.

In addition to the Public Staff, the following parties intervened in the 2008 proceeding: the Carolina Industrial Group for Fair Utility Rates I, II, III ("CIGFUR"); the North Carolina Waste Awareness and Reduction Network, Inc. ("NC WARN"); the Carolina Utility Customers Association, Inc. ("CUCA"); GreenCo; Fibrowatt LLC ("Fibrowatt"); and the North Carolina Sustainable Energy Association ("NCSEA"). The Attorney General filed a Notice of Intervention pursuant to G.S. 62-20.

On January 29, 2009, Fibrowatt filed comments regarding the REPS compliance plans. On April 16, 2009, NC WARN filed its initial comments on the 2008 Plans and a request for 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 in the Docket No. E-100, Sub 118 proceeding.

On May 27, 2009, reply comments were filed by Duke, PEC, DNCP, and the Public Staff. On the same day, additional comments were submitted by NC WARN.

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 Docket No. E-100, Sub 118 for August 31, 2009.

On August 12, 2009, NC WARN filed a Motion for Reconsideration and Renewal of Request for Hearing.

A public hearing was held as scheduled on August 31, 2009, with six public witnesses in attendance. All six public witnesses testified in regard to REPS compliance plan issues.

Docket No. E-100, Sub 124

On or about September 1, 2009, the 2008 Plans were updated ("2009 Plan") and filed with the Commission by PEC, Duke, DNCP, NCEMC, Piedmont EMC, Rutherford EMC, and EnergyUnited EMC. Additionally, a 2009 Plan was filed by Haywood EMC and Blue Ridge EMC has filed notice that its electric load is now included in Duke's integrated resource plan.

Additionally, 2009 REPS compliance plans were filed by PEC, Duke, DNCP, Halifax EMC, and EnergyUnited. A consolidated 2009 REPS compliance plan was filed by GreenCo on behalf of its 22 member EMCs. Rutherford filed notice that its REPS obligation is now reflected in Duke's REPS compliance plan.

At that time, the following parties had intervened in the 2009 integrated resource plan proceeding: Environmental Defense Fund (“EDF”), Southern Alliance for Clean Energy (“SACE”), the Sierra Club, the Southern Environmental Law Center (“SELC”), CPI USA North Carolina, LLC (“CPI NC”), 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. 62-20. The Public Staff was also a party.

Combined Docket Nos. E-100, Subs 118 and 124

On October 19, 2009, the Commission issued an Order Scheduling Hearings on 2009 Integrated Resource Plans and REPS Compliance Plans and Consolidating Dockets for Decision (“October 19 Order”). In the October 19 Order, the Commission noted that the updated 2009 Plans superseded much of the information contained in the 2008 Plans. The Commission therefore decided to consolidate the Sub 118 and Sub 124 dockets for decision purposes. Further, in this Order the Commission found good cause to schedule an evidentiary hearing to consider the 2009 Plans and REPS compliance plans filed by the investor-owned utilities that are subject to Commission regulation as a replacement for the normal comment process specified by Commission Rule R8-60(j), and stated that it saw no need for an evidentiary hearing on the 2008 Plans in view of the fact that interested parties had previously filed comments in the Sub 118 docket. Accordingly, the October 19 Order scheduled an evidentiary hearing for March 16, 2010 to consider the 2009 Plans and REPS Compliance Plans filed by the investor-owned utilities and scheduled a non-expert public witness testimony hearing regarding all 2009 Plans and REPS Compliance Plans for March 15, 2010. The Order also directed the Public Staff

and other interveners to address the non-IOUs' 2009 Plans by comments and the IOUs' 2009 Plans by testimony.

On December 11, 2009, DNCP filed the direct testimonies and exhibits of Shannon L. Venable, M. Masood Ahmad, Michael J. Jesensky, and Aaron A. Reed; and Progress filed the direct testimonies of David K. Fonvielle, David C. Edge, and Glen A. Snider.

On January 11, 2010, Duke filed its revised 2009 Plan, together with the direct testimonies and exhibits of Richard G. Stevie, Owen A. Smith, Robert A. McMurry, and James A. Riddle.

On February 8, 2010, the Public Staff filed comments pertaining to the 2009 Plans and the 2009 REPS compliance plans filed by the non-investor owned utilities. Participation in these proceedings by the Public Staff is being made pursuant to the provisions of G.S. 62-15(d) and Commission Rule R1-19(e).

On February 19, 2010, CPI USA North Carolina, LLC filed the direct testimony of Don C. Reading; and the Environmental Defense Fund, Southern Environmental Law Center, Southern Alliance for Clean Energy, and the Sierra Club filed the direct testimonies of David Schlissel and John D. Wilson. Also on February 19, 2010, the Public Staff filed the testimony of John R. Hinton and the affidavits of Jay B. Lucas, Jack L. Floyd, and Kennie D. Ellis; and the North Carolina Waste Awareness and Reduction Network, Inc. filed the direct testimony and exhibits of John O. Blackburn.

On February 23, 2010, Duke filed confidential Revised Table 2 to its Revised 2009 Plan.

On March 2, 2010, the Public Staff filed revisions to the Affidavit of Jay B. Lucas.

On March 9, 2010, Progress filed the rebuttal testimonies of its witnesses Fonvielle, Edge, and Snider; and DNCP filed the affidavit of witness Venable. Also on March 9, 2010, Duke filed revisions to the direct testimony of witness Stevie; revised Exhibit Nos. 1 and 3 of the direct testimony of witness Riddle; and the rebuttal testimonies of witnesses McMurry and Stevie.

On March 11, 2010, Haywood EMC filed a response to the February 8, 2010 Public Staff comments.

Ten public witnesses testified before the Commission on March 15, 2010: Mike Cherin; June Blotnick; Alice Loyd; Elizabeth Hutchby; Beth Henry; Miriam Thompson; Bob Rodriguez; Zell McGee; Harry Phillips; Mary McDowell; and Ryan Thompson (actually testified 3/16/10).

An evidentiary hearing was held on March 16-18, 2010 regarding the 2009 Plans and REPS compliance plans.

2008 INTEGRATED RESOURCE PLANS

In Docket No. E-100, Sub 118, the Public Staff reviewed the 2008 Plans of the three IOUs for the following issues: peak and energy forecasts; reserve margins; reserve margin adequacy; busbar information; transmission adequacy; transmission collaborative; non-utility generation; wholesale contracts for purchase and sale of power; demand-side management and energy efficiency options; alternative supply-side energy resources; and REPS compliance plan review. In general, the Public Staff determined that the electric utilities' 2008 Plans were satisfactory with regard to these issues. Since the Commission

stated in its October 19 Order that the 2009 Plans supersede much of the information contained in the 2008 Plans, this Proposed Order will focus on the 2009 Plans submitted in Docket No. E-100, Sub 124, except where it may be appropriate to discuss the 2008 Plans.

2009 INTEGRATED RESOURCE PLANS

As discussed above, on or about September 1, 2009, the 2009 Plans were filed by Progress, Duke, DNCP, NCEMC, Piedmont EMC, Rutherford EMC, and EnergyUnited EMC. Additionally, a 2009 Plan has been filed by Haywood EMC and Blue Ridge EMC has filed notice that its electric load is now included in Duke's 2009 Plan.

Additionally, 2009 REPS compliance plans have been filed by Progress, Duke, DNCP, Halifax EMC, and EnergyUnited. Additionally, GreenCo filed a consolidated 2009 REPS compliance plan on behalf of its 22 member EMCs. Rutherford has filed notice that its REPS obligation is now reflected in Duke's REPS compliance plan.

1. Forecasts of Load, Supply-Side Resources, and Demand-Side Resources

Rules R8-60(c) and R8-60(i)(1) require that each utility's integrated resource plan contain forecasts of load, supply-side resources, and demand-side resources. These forecasts must include descriptions of the methods, models, and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWh) forecasts and the variables used in the models. The forecasts included in both the biennial and annual reports must contain: (1) the most recent ten-year history and a forecast of customers by each customer class and the most recent ten-year history and forecast of energy sales (kWh) by each customer class; (2) a tabulation of the utility's forecast for at least a 15-year period, including peak loads for summer and winter seasons of each year, annual energy

forecasts, reserve margins, and load duration curves; and (3) where future supply-side resources are required, a description of the type of capacity/resource (base, intermediate, or peaking) that the utility proposes to use to address the forecasted need.

Public Staff Affiant Hinton reviewed the compound annual growth rates (“CAGR”) of the IOUs’ forecasts of their annual peak demands and energy sales, the historical growth of weather-normalized peak demands and weather-normalized energy sales, and several of the regression equations and key assumptions underlying the forecasts and the growth rates of forecasts for other adjoining IOUs and forecasts for Southeastern Reliability Corporation (“SERC”).

DNCP

DNCP used econometric models with an end-use orientation to forecast energy sales at the customer class level and hourly loads at the system level. Separate monthly sales equations were developed for residential, commercial, industrial, public authority, street and traffic lighting, and wholesale customers, as well as other load-serving entities (“LSEs”) within the Dominion Zone (“DOM Zone”) of the PJM Interconnection (“PJM”). The monthly sales equations were specified in a manner that produced estimates of non-weather sensitive load, heating load, and cooling load. Hourly equations were used to model peak demands and energy output for the DOM Zone. Hourly models for industrial customers and other LSEs in the DOM Zone were modeled as a function of the DOM Zone load since they face similar weather and economic activity. The DOM LSE load was derived by subtracting the other LSEs from the DOM Zone load. DOM LSE load and firm contractual obligations were used as the total load obligation for the purpose of DNCP’s 2009 Plan. Forecasts were produced by simulating

the model over actual weather data from the past 20 years along with projected economic conditions. Sales estimates from the monthly equations and energy output projections from the hourly model were reconciled appropriately. Monthly sales by customer class, peak demand, and system energy were calculated as expected values across the simulations.

DNCP's 15-year forecast (2010-2024) resulting from this process predicts that its summer peak will increase at a CAGR of 2.16%, an increase of 0.26% from DNCP's 2007 integrated resource plan ("2007 Plan"), and its winter peak will grow at a CAGR of 1.92%, an increase of 0.42% from DNCP's 2007 Plan. The average annual growth of the summer peak is 411.73 MW for the next 15 years, compared to 353 MW forecasted in the 2007 Plan.

DNCP predicts that its total energy sales will grow at an average annual rate of 2.39%. DNCP reported that its energy sales and load forecasts were driven by positive forecasts for the Virginia economy in terms of unemployment rate, housing starts, and per-capita and population income.

Public Staff did not have any concerns with DNCP's forecasts of peak demand and energy sales. After adjusting for DNCP's DSM and EE programs, the growth rate of DNCP's summer peak demand from 2010 through 2024 is 2.0%, and the growth rate for total energy sales is 2.2%.

Other Issues

The Public Staff reviewed Duke's, PEC's, and DNCP's (1) projections of population and personal income, (2) forecast accuracy by comparing forecasts from the 2004 integrated resource plan ("2004 Plan") with actual loads and (3) inputs to the IOUs'

production cost simulation models to optimize the supply- and demand-side resources to determine expansion plans that offer reliable power at least cost. After performing these reviews, the Public Staff concluded that the IOUs' assumptions regarding population and personal income were reasonable, the 2004 peak and energy forecasts by Duke, PEC, and DNCP had less than a 5% forecast error, their forecasts are valued and reasonable for planning purposes, and the inputs used in the IOUs' production cost simulation models, which create combinations of resource alternatives to find the least cost mix of resources under simulated conditions, did not raise any concerns.

Public Staff noted that all three IOUs have reduced their forecasted peak loads and energy sales by the impacts of their DSM and EE programs. Regarding DSM, the Public Staff stated that production simulation models used by the IOUs incorporate controls that allow them to set the available run hours and the incremental cost rate for each program. In general, a low number of available run hours and a high cost rate relative to other supply-side resources tend to limit the activation of load control to emergency or "near" emergency situations. Public Staff Affiant Hinton stated that increasing activation of load control would not defer or eliminate an additional combustion turbine or combined cycle facility, mainly because the model runs load control to address peak demand. He observed that air conditioner cycling could reduce peak demand and reduce fuel costs. In her rebuttal, DNCP witness Shannon L. Venable states 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 formally filed and approved in North Carolina and operational data can be

further analyzed. The Commission concludes that this is an appropriate approach to determining how best to utilize the potential of air conditioner cycling to lower fuel costs.

Conclusion

Based on the foregoing, the Commission concludes that the forecasts of load, supply-side resources, and demand-side resources of PEC, Duke, and DNCP are reasonable and appropriate.

2. Generating Facilities

Rule R8-60(i)(2) requires that each utility provide certain information for its existing and planned electric generating facilities as well as for its non-utility generation.

DNCP

DNCP's 2009 Plan stated that its existing generation resources are located at multiple sites distributed geographically around its service territory, and include 4 nuclear, 23 coal, 1 wood, 2 natural gas, 2 heavy oil, 7 combined cycle, 46 combustion turbine, 6 pumped storage, and 14 hydro units. Together the 105 generating units carry a summer capacity of more than 16,000 MW. This total includes more than 400 MW of renewable generation capacity in Virginia and North Carolina. DNCP explained that due to differences in the operating and fuel costs of various types of units and PJM system conditions, the Company's generation mix is not equal to its capacity mix. Its generation fleet is economically dispatched within the larger PJM footprint, allowing customers within DNCP's service area to benefit from all resources in the PJM power pool regardless of whether the source is Company-owned, contracted, or third-party units. PJM dispatches the resources in the DOM Zone from the lowest marginal cost units to the highest marginal cost units. DNCP's 2009 capacity mix included 26% coal, 24%

natural gas, 17% nuclear, 12% hydro, 11% oil, 10% purchases, and 0.5% non-hydro renewable. DNCP's 2009 energy mix included 40% coal, 33% nuclear, 12% purchases, 11% natural gas, 2% hydro, 0.7% oil, and 0.5% non-hydro renewables. DNCP included a list of existing generation units in service in Appendix 3A of its 2009 Plan.

DNCP provided information on planned changes to existing generating units, and explained that efficiency, output, and environmental plant characteristics are reviewed and improved upon as available through the Company's normal course of business. The Company noted that over the past two years it has increased its generating capacity by over 600 MW through the addition of new peaking units and uprates of existing units. DNCP's future plans include emission-reduction efforts including converting coal-fired Bremo Power Station to gas, pending State Corporation Commission of Virginia ("SCC") approval, and pending retirements of several units within the planning period. DNCP included a list of planned changes to its existing generation units in Appendix 3I of its 2009 Plan.

DNCP described several planned additions to its baseload and intermediate load capacity including the Bear Garden Power Station and Virginia City Hybrid Energy Center, which are under construction, and the Warren County combined cycle plant and North Anna Unit 3, which are under development. In addition, DNCP included a list of these planned generation resources in Appendix 3K of its 2009 Plan.

Regarding non-utility generation, DNCP reports that it has contracted with several NUGs that supply over 1,770 MW of firm capacity and associated energy to meet DNCP's load requirements. While all of these contracts are set to expire during the planning period, at which point the capacity from those resources would not be used as a

firm resource for planning purposes, NUGs that continue to operate in the PJM market could make their energy and capacity available to DNCP through the competitive wholesale market or as a bilateral resource. The NUGs under contract with DNCP include seven baseload units, one intermediate unit, and one peaking unit. Appendix 3B to DNCP's 2009 Plan contains a list describing NUGs included as capacity resources for the Company, as well as behind-the-meter generation units that are not capacity resources.

Comments

Public Staff Affiant Ellis stated that his investigation of the IOUs' 2009 Plans indicates that each utility's discussion of generating facilities, including non-utility generation, appears to meet the requirements of R8-60.

Conclusion

Based on the foregoing, the Commission concludes that Duke, PEC, and DNCP have met the requirements of Rule R8-60(i)(2) with regard to generating facilities.

3. Reserve Margins

Rule R8-60(i)(3) requires that each utility must provide a calculation and analysis of its winter and summer peak reserve margins over the projected 15-year period, and must explain the reasons for any difference of plus or minus 3% between the margins produced in a given year and the target reserve margins.

DNCP

DNCP's 2009 Plan stated that DNCP participates in PJM planning processes for short-term (PJM's Reliability Pricing Model ("RPM")) and long-term (PJM's Reserve Requirement Study) capacity planning. DNCP also explained how it applies PJM reserve

margin requirements to its own reserve modeling efforts. For the 15-year planning period (2010 – 2024), DNCP projects a summer reserve requirement ranging from 2,191 MW to 3,040 MW. The effective reserve margin represented by these requirements decreases slightly from 17.4% in 2010 for the next two years, based on outcomes of RPM auctions that have cleared, and are projected at 12.0% for the remaining years of the planning period based on the PJM recommended reserve margin of 16.2% together with DNCP's coincidence factor of 94.6%. The total resource requirement for DNCP for the planning period, which represents DNCP's total resource need met through existing resources, construction of new resources, DSM programs, and market capacity purchases, grows from 19,887 MW in 2010 to 25,372 MW in 2024.

Comments

Public Staff Affiant Ellis stated that his investigation of the IOUs' 2009 Plans indicates that each utility's discussion of reserve margin adequacy appears to meet the requirements of R8-60.

Conclusion

Based on the foregoing, the Commission concludes that the PEC, Duke, and DNCP appear to meet their projected reserve margin targets for the planning period.

4. Wholesale Contracts for Purchase and Sale of Power

Rule R8-60(d) requires that each utility assess on an ongoing basis, as part of its integrated resource planning ("IRP") process, the potential benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity. In addition, Rule R8-60(i)(4) requires that each utility's integrated resource plan reflect its firm wholesale purchased power contracts, discuss the results of any

Request for Proposal (“RFP”) for purchased power, and discuss any wholesale power sale contracts for the sale of capacity or firm energy.

DNCP

DNCP’s 2009 Plan stated that other than NUG contracts, the Company does not have any bilateral obligations with wholesale power suppliers or marketers. As a member of PJM, DNCP has the option to self-schedule or buy capacity through the RPM auction process. DNCP reports that it has procured its capacity obligation from the RPM market through May 31, 2013.

DNCP currently provides full requirements wholesale power sales to three entities, and has partial requirements contracts to supply the supplemental power of needs to two electric cooperatives.

DNCP reported that it conducted an RFP to solicit proposals for construction of a gas-fired CC generating plant for commercial operation in 2011, requesting proposals for approximately 580 MW of new, intermediate capacity. Based on its assessment of the proposals it received, DNCP chose the Bear Garden CC project as the best solution to meet its need.

As discussed above, pursuant to Rule R8-60(i)(2)(iii), DNCP provided a list of all NUGs that it uses as capacity resources in Appendix 3B of its 2009 Plan. Each of the NUGs listed in Appendix 3B is under contract to supply capacity and energy to DNCP.

Comments

Public Staff Affiant Ellis stated that his investigation of the IOUs’ 2009 Plans indicates that each utility’s discussion of wholesale power contracts appears to meet the requirements of R8-60.

Conclusion

Based on the foregoing, the Commission concludes that Duke, PEC and DNCP have met the requirements of Rule R8-60(i)(4) with regard to wholesale contracts for purchase and sale of power.

5. Transmission Facilities

Pursuant to the Commission's March 28, 2002 Order in Docket No. E-100, Sub 93, the electric utilities must include a copy of their most recent FERC Form 715 and a discussion of their transmission line inter-tie capabilities, transmission line loading constraints, planned new construction and upgrades, and North American Electric Reliability Corporation ("NERC") compliance within their respective control areas for the planning period under consideration. In addition, Rule R8-60(i)(5) requires each utility to include a list of transmission lines and other associated facilities (161 kV or over) which are under construction or for which there are specific plans to be constructed during the planning horizon, and discuss the adequacy of its transmission system.

DNCP

DNCP filed its FERC Form 715 with the Commission at the same time it filed its 2009 Plan. DNCP's 2009 Plan states that it has over 6,000 miles of transmission lines in Virginia, North Carolina, and West Virginia at voltages ranging from 69 kV to 500 kV, all of which are integrated into PJM. During 2009, DNCP added the 230 kV Bristers-Gainsville line in Virginia, and plans to add the Kitty Hawk-Colington 115 kV line in North Carolina in 2010. DNCP provided a list of planned transmission interconnection projects for the planning period.

DNCP added that its transmission system is developed and maintained in order to comply with the NERC Reliability Standards as well as SERC Supplements to those standards. In addition, DNCP participates in the PJM Regional Transmission Expansion Plan, which seeks to develop a Regional Transmission Organization (“RTO”)-wide transmission plan for PJM, and the Virginia-Carolinas Reliability Agreement (“VACAR”).

DNCP included a list of its existing transmission and distribution lines listed in its most recently filed FERC Form 1 in Appendices 3Q, 3R, 3T, 3U, and 3V of its 2009 Plan. In addition, DNCP included a list of its transmission interconnection projects under construction with associated enhancement costs in Appendix 3W of its 2009 Plan, and a *list of DNCP’s transmission lines and associated facilities either under construction or subject to plans to be constructed in Appendix 3X.*

Comments

Public Staff Affiant Ellis stated that his investigation of the IOUs’ 2009 Plans indicates that each utility’s discussion of transmission facilities appears to meet the requirements of R8-60.

Conclusion

Based on the foregoing, the Commission concludes that Duke, PEC and DNCP have met the requirements of Rule R8-60(i)(5) with regard to Transmission Facilities.

6. Demand-Side Management

Rule R8-60(f) requires that as part of its IRP process, each utility assess on an ongoing basis programs to promote DSM, including costs, benefits, risks, uncertainties, reliability and customer acceptance. For purposes of this rule, DSM includes DR, EE,

and conservation programs. In turn, Rule R8-60(c)(6) requires that each utility provide the results of its overall assessment of existing and potential demand-side management programs, including a descriptive summary of each analysis performed or used by the utility in the assessment.

DNCP

DNCP stated its intention to promote DSM for all of its customers in Virginia and North Carolina, and outlined its efforts related to EE, peak-shaving, and DR initiatives. DNCP reported that on July 29, 2009, it filed its initial DSM Portfolio of 12 programs for its Virginia customers. DNCP noted that it had not, at the time of filing its 2009 Plan, filed for approval of DSM programs in North Carolina, but that no demand-side resources had been discontinued since the filing of its 2008 Plan. DNCP noted that when it does file its EE and DSM programs for North Carolina, it will ensure that it meets the North Carolina legislative definitions contained at G.S. 62-133.8(a)(2) and (4) for DSM and EE measures.

DNCP included in its 2009 Plan a list and description of current and proposed DSM resources, and noted that it models existing demand-side pricing tariffs over a 15-year planning period based on historical data from its Customer Information Systems. The current DSM initiatives offered by DNCP include standby generation, curtailable service tariffs, and a compact fluorescent light (“CFL”) price reduction program. Of those, DNCP has 7 customers on Schedule 6C for curtailable service in North Carolina. DNCP activated its NC Schedule 6C service 19 times during the summer of 2008 and achieved approximately 5 MW of demand reduction, and achieved approximately another 5 MW of demand reduction from 3 activations during the winter of 2008-2009.

On March 24, 2010, DNCP received approval from the Virginia SCC to implement five DSM programs in its Virginia service territory: Residential Lighting Program; Low Income Program; Commercial HVAC Upgrade Program; Commercial Lighting Program; and Air Conditional Cycling Program. The Company plans to evaluate these programs and others considered for implementation in Virginia for approval and implementation in DNCP's North Carolina's service territory. DNCP projects DSM reductions of 500 MW over the short-term (2010-2014) and an additional 450 MW of reduction between 2015 and 2024.

Comments

Public Staff Affiant Floyd investigated and made recommendations regarding DSM and EE resources within the 2009 Plans of the investor owned utilities as well as the pertinent portions of those utilities' 2008 Plans. The Public Staff testified that with respect to the evaluation and inclusion of DSM and EE and the level of DSM and EE used in the calculations of planning reserves, the 2009 Plans do not differ materially from the IOUs' 2008 Plans. Duke, PEC, and DNCP each included in their planning horizon slightly lower impacts from DSM and EE resources than were included in their 2008 Plans. Public Staff attributed this change to the delays in implementation of DSM and EE programs due to the current economic conditions, as well as delays in the timing of development, approval, and rollout of the various programs within each IOU's portfolio. Notwithstanding these delays, the Public Staff found that the IOUs continue to incorporate DSM and EE as fundamental resources in their Plans, and stated that it continues to work with the IOUs regarding new DSM and EE programs. The Public Staff

stated its expectation that some of these new programs will be submitted for Commission approval in the near future.

The Public Staff's investigation of the use of DSM by the IOUs during their respective peak periods shows that DNCP and PEC indicated that they utilized DSM resources during their August 10, 2009 peak hours. Duke's peak period occurred the same day, but Duke indicated that no DSM was utilized during that period of time.

The Public Staff noted that PEC and Duke generally modeled their DSM resources consistent with the modeling of DSM resources in their individual program approval proceedings, and that DNCP has not yet submitted any new DSM or EE programs for approval under G.S. 62-133.9 or Commission Rule R8-68. It concluded that the IOUs should utilize their DSM resources to obtain the maximum system value possible, and noted that while further capacity savings may not result from increased utilization, additional energy savings, with corresponding fuel savings, could result during periods when energy prices are typically greater than the costs of operating these DSM resources.

Public Staff Affiant Floyd suggested, upon review of the utilities' DSM and EE programs, that the utilities should consider air conditioner cycling programs. DNCP responded that it has 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 formally filed and approved in North Carolina and operational data can be further analyzed. As determined above with regard to peak and energy forecasts, the Commission concludes that this is an appropriate approach to determining how best to utilize the potential of air conditioner cycling to lower fuel costs.

The Environmental Respondents witness Wilson suggested that DNCP failed to provide certain information including capacity, energy, and number of customers for its DSM programs in its 2009 Plan. DNCP responded that this information is included in the Appendix to the 2009 Plan. The Commission concludes that the information provided by DNCP at the Appendix to its 2009 Plan is sufficient for evaluation of its DSM programs.

Citing Commission Rule R8-60(c)(1), Environmental Respondents witness Wilson also suggested that DNCP's Commercial Distributed Generation ("Commercial DG") Program should be characterized as a supply-side resource. In response, DNCP disagreed with this suggestion, and stated that it has classified the proposed Commercial DG Program as a demand-side resource because it has the attributes of a demand-side program: (1) the Commercial DG Program reduces load on the system; (2) the generator is located behind the customer's meter and it is not a DNCP-owned resource; and (3) DNCP pays the customer an incentive for using the generator on their premises, which would classify the resource as a demand-side resource, not a supply-side resource. In addition, DNCP stated that because Commercial DGs are located at the customer location, they can provide avoided cost benefits resulting from reductions in future transmission and distribution costs as well as reductions in system transmission and distribution losses consistent with being a demand-side resource. DNCP clarified that supply-side options generally do not produce these types of benefits. The Commission concludes that DNCP's classification of the Commercial DG program as a demand-side resource is reasonable.

Environmental Respondents witness Wilson also suggested that the utilities should meet an annual energy savings goal of 1%. In response, DNCP argued that this is

not the standard established by Senate Bill 3, and stated that DNCP is committed to pursuing energy efficiency that is cost-effective and appropriate for its customers. The Commission agrees that Senate Bill 3 does not mandate an annual energy savings goal of 1% and concludes that it is not appropriate to require such a goal at this time.

Finally, Environmental Respondents witness Wilson recommended the establishment of a regional energy efficiency database and collaboration process for the purpose of furthering strong energy efficiency analysis and program development. DNCP responded that although it does not support the creation of a regional energy efficiency database and collaboration process, it does support an inclusive stakeholder process. The Commission concludes that the goals of furthering DSM and EE as articulated by Senate Bill 3 are being adequately addressed through the current IRP process for development and review, and moreover that this proceeding is not the appropriate forum to consider the establishment of a regional energy efficiency database and collaboration process.

Conclusion

Based on the foregoing, the Commission concludes that the utilities have met the requirements of Rule R8-60(c) with regard to DSM and EE options.

7. Assessment of Alternative Supply-Side Energy Resources

Rule R8-60(e) requires each utility, as part of its IRP process, to assess on an ongoing basis the potential benefits of reasonably available alternative supply-side energy resource options. In turn, Rule R8-60(i)(7) requires each utility to file an assessment of existing and potential alternative supply-side energy resources, and provide general

information on any changes to the methods and assumptions used in its assessment since its most recent biennial or annual report.

DNCP

DNCP explained the process it used to assess alternative supply-side energy resources and reported that it is monitoring the following alternative supply-side energy resources: coal-fired integrated gasification combined cycle (“IGCC”) technology, fuel cell, solar photovoltaic, solar thermal, tidal and wave power, and wind.

Comments

Public Staff Affiant Lucas reported that DNCP owns and operates an 83-MW power plant in Hurt, Virginia that is capable of using biomass, typically waste wood, as its sole fuel source. It is also constructing the 585-MW Virginia City Hybrid Energy Center near Wise, Virginia, which can use up to 20% biomass as a fuel source. DNCP applied for federal stimulus funds for researching carbon capture and sequestration at this site.

High costs and uncertain efficiency have caused DNCP not to pursue IGCC. Fuel cell technology has not proven effective for utility-scale operation. DNCP ruled out tidal and wave power because no applications were commercially available. DNCP views wind energy as having potential but does not yet have sufficient information on wind energy’s viability in its service territory.

Conclusion

Based on the foregoing, the Commission concludes that the utilities have met the requirements of Rule R8-60(e) with regard to assessment of alternative supply-side energy resources.

8. Evaluation of Resource Options

Rule R8-60(g) requires that as part of its IRP process, each utility consider and compare a comprehensive set of potential resource options, including both demand- and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliability resource options for meeting its anticipated system needs. Rule R8-60(i)(8) requires that each utility provide a description and a summary of the results of the analyses of potential resource options and combinations of resource options to determine its integrated resource plan as required by Rule R8-60(g).

DNCP

DNCP's 2009 Plan contains an examination of future supply-side resources, including biomass, carbon capture and sequestration, coal-fired Circulating Fluidized Bed ("CFB"), IGCC, gas-fired combined cycle, gas-fired combustion turbine, fuel cell, geothermal, nuclear, pulverized coal, hydro power, solar photovoltaic, solar thermal, tidal and wave power, and wind energy. DNCP also included a description of its analysis of potential demand-side resources, which focused on cost-effectiveness, stakeholder impacts, potential for achieving customer acceptance, and potential for energy and demand reductions, and modeled these resources over a 15-year planning period. DNCP described the tests it utilized to analyze these potential resources and outlined potential future DSM programs.

Comments

Public Staff Affiant Ellis stated that his investigation of the IOUs' 2009 Plans indicates that each utility's discussion of evaluation of resource options appears to meet the requirements of R8-60.

Conclusion

Based on the foregoing, the Commission concludes that the utilities have met the requirements of Rule R8-60(g) and Rule R8-60(i)(8) with regard to evaluation of resource options.

9. Levelized Busbar Costs

Rule R8-60(c)(9) requires that each utility provide information on levelized busbar costs for various generation technologies.

DNCP

DNCP's 2009 Plan states that the Company's busbar model was designed to estimate the levelized busbar costs of various technologies on an equivalent basis. The busbar results show the levelized cost of power generation at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. The results of DNCP's busbar model showed CT and CC technologies, along with biomass and nuclear resources, to be most cost-effective for meeting its requirements. DNCP also ran its model for non-dispatchable technologies, resulting in a preferred order of hydro, onshore wind, solar thermal, solar photovoltaic, and offshore wind for consideration. DNCP stated that while the busbar analysis, together with its assessment of alternative resource types, provided a useful foundation for selecting resources for further analysis, the busbar curve was static due to its reliance on averaging all cost data over the resource lifetime. To compensate, DNCP conducted further

analysis using its Strategist model, which incorporates seasonal variations in cost and operating characteristics while integrating new resources with system resources. In this way DNCP reports it produced a more accurate match of resources found to be cost-effective ways of meeting its current and future needs.

Comments

Public Staff Affiant Ellis stated that his investigation of the IOUs' 2009 Plans indicates that each utility's discussion of levelized busbar costs appears to meet the requirements of R8-60.

Conclusion

Based on the foregoing, the Commission concludes that the utilities have met the requirements of Rule R8-60(i)(9) and its Order dated July 9, 2007, in Docket No. E-100, Sub 109, with regard to provision of levelized busbar costs for various generation technologies.

REPS COMPLIANCE PLANS

G.S. 62-133.8 requires all electric power suppliers to provide specified percentages of their retail sales using renewable energy resources or reduce energy consumption through implementation of EE measures. Commission Rule R8-67(b) requires electric power suppliers to file a REPS compliance 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 REPS compliance plans must cover the current year and the next two calendar years, or in this case 2009, 2010 and 2011. The only compliance requirement covered by this planning period is found in G.S. 62-133.8(d) for solar energy resources. Electric power suppliers must meet 0.02% of their retail sales in 2010 and

2011 using solar photovoltaic or solar thermal energy. Finally, Rule R8-60(c) requires that each utility's integrated resource plan—its consideration of supply-side and demand-side resources, including alternative supply-side energy resources, and the provision of reliable electric utility service at least cost—consider and incorporate the utility's obligation to comply with the REPS requirements.

DNCP

DNCP's REPS compliance plan states its intention to meet the REPS requirements through 2021 and thereafter through a combination of new renewable energy, energy efficiency, and renewable energy certificates ("RECs").

Regarding the solar set-aside requirements that took effect in 2010, DNCP intends to purchase solar RECs to meet the set-aside requirements for 2010 and 2011, but will obtain bundled solar energy if necessary. For DNCP, 0.02% of anticipated sales for the solar set-aside equates to 757 MWh in 2010 and 753 MWh in 2011. DNCP's plan to purchase solar RECs should be sufficient to meet its requirements for 2010 and 2011 since G.S. 62-133.8(b)(2) allows DNCP to purchase all necessary RECs from outside of North Carolina.⁵

DNCP plans to utilize EE to meet a portion of its REPS requirements, and to seek Commission approval of seven potential EE programs in the near future. The total amount of projected energy savings from these programs in 2011 is 5,090 MWh. The Public Staff commented that it expects DNCP to request Commission approval of these EE programs sometime in 2010.

⁵ *In the Matter of Rulemaking Proceeding to Implement Session Law 2007-397*, Order on Dominion's Motion for Further Clarification, Docket No. E-100, Sub 113 (Sept. 22, 2009).

DNCP's REPS compliance plan also addresses, pursuant to Rule R8-67(b), retail sales and customer accounts, avoided cost rates, total project costs of compliance with the REPS, comparison of total costs with annual cost caps, an estimate of its REPS rider, and a statement regarding registration of renewable energy facilities.

In response to Public Staff Affiant Lucas' observation that DNCP did not mention a problem finding poultry and swine renewable energy or RECs in its REPS compliance plan, DNCP responded that it has indeed been having difficulty obtaining those resources, and has participated as a joint movant on assignment and implementation issues for swine and poultry waste issues in Docket No. E-100, Sub 113, discussed further below.

Other Issues

Duke and other electric power suppliers in North Carolina have had difficulty securing resources to meet the poultry and swine waste set-asides required in G.S. 62-133.8(e) and (f). They have made joint filings with the Commission in Docket No. E-100, Sub 113. On August 14, 2009, several electric power suppliers including Duke, PEC, and DNCP ("Joint Movants") filed a motion requesting that the Commission delay and reduce the poultry waste set-aside requirement and delay the swine waste set-aside requirement. Numerous parties filed comments opposing the Joint Movants' request. On December 16, 2009, the Joint Movants withdrew their request regarding poultry waste, stating that they had resolved their primary issues with North Carolina's poultry waste generators. On January 29, 2010, the Joint Movants, together with several parties interested in generating power from poultry and swine waste, requested Commission approval of an RFP for swine waste generation. On February 5, 2010, several electric

power suppliers and other interested parties jointly filed for approval of an allocation method for the poultry and swine waste set-asides. Under G.S. 62-133.8 these two set-asides are designated as aggregate requirements for all electric power suppliers in the State. On February 12, 2010, the Commission issued an Order on Withdrawal of Joint Motion, Issuance of Joint Request for Proposals, and Allocation of Aggregate Set-Aside Requirements that

Public Staff concluded that Duke, PEC, and DNCP can meet their REPS requirements for the time period covered by their REPS compliance plans (2009, 2010, and 2011).

Conclusion

Based on the foregoing, the Commission concludes that Duke, PEC, and DNCP have met the requirements of Rules R8-67(b) and R8-60(c) with regard to submission of a REPS compliance plan and approves the REPS compliance plans as appropriate.

CONCLUSIONS

The Commission's review of the 2009 Plans concludes that the utilities responded appropriately to all of the requirements of Rule R8-60 and Rule R8-62(p), as well as the requirements of the Commission's past IRP orders and Senate Bill 3. Duke, PEC and DNCP have demonstrated that their IRP processes have adequately considered the required issues of forecasts of load, supply-side resources, and demand-side resources; generating facilities; reserve margins; wholesale contracts for the purchase and sale of power; transmission facilities; demand-side management; assessment of alternative supply-side energy resources; evaluation of resource options; and levelized busbar costs

in order to produce a least cost and reliable mix of electric generation to satisfy their respective demands.

The Commission has also reviewed the REPS compliance plans submitted by the utilities pursuant to Rule R8-67(b) and concludes that it is appropriate to approve the REPS compliance plans as submitted. The Commission notes that, pursuant to Rule R8-67(b)(3), our approval of the REPS compliance plans does not constitute an approval of the recovery of costs associated with REPS compliance or a determination of compliance with G.S. 62-133.8(b), (c), (d), (e) and (f).

IT IS, THEREFORE, ORDERED as follows:

1. That this Order shall be adopted as part of the Commission's current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to G.S. 62-110.1(c);
2. That the 2009 Plans filed in this proceeding by the utilities are hereby approved; and
3. That the REPS compliance plans filed in this proceeding by the utilities are hereby approved.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of _____, 2010.

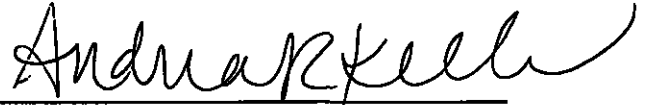
NORTH CAROLINA UTILITIES COMMISSION

Renne Vance, Chief Clerk

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Proposed Order of Dominion North Carolina Power was served upon all parties of record in Dockets No. E-100, Sub 118 and E-100, Sub 124 by first-class mail, postage prepaid, or by electronic mail.

This, the 11th day of June, 2010.



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