NORTH CAROLINA UTILITIES COMMISSION

Volume I

Pages 1 to 276

105th REPORT
JAN. 1, 2015
DEC. 31, 2015

ONE-HUNDRED FIFTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume I

ISSUED FROM
JANUARY 1, 2015 THROUGH DECEMBER 31, 2015

ONE-HUNDRED FIFTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2015, through December 31, 2015

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

Don M. Bailey, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
Gail L. Mount
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

LETTER OF TRANSMITTAL

December 31, 2015

The Governor of North Carolina
Raleigh, North Carolina

Sir:

Pursuant to the provisions of Section 62-17(b) of the General Statutes of North Carolina, providing for the annual publication of the final decisions of the Utilities Commission on and after January 1, 2015, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2015, and ending December 31, 2015.

The additional report provided under G.S. 62-17(a), comprising the statistical and analytical report of the Commission, is printed separately from this volume and will be transmitted immediately upon completion of printing.

Respectfully submitted,

NORTH CAROLINA UTILITIES COMMISSION

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

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DOCKET NO. E-100, SUB 56

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Decommissioning Costs for Nuclear	)	
Power Plants Owned and Operated by	)	
Carolina Power & Light Company, Inc., d/b/a	)	ORDER AUTHORIZING DEFERRAL
Progress Energy Carolinas, Inc., Duke Energy	)	OF DUKE ENERGY
Carolinas, LLC, and Virginia	)	CAROLINAS, LLC'S
Electric and Power Company, d/b/a	)	DECOMMISSIONING EXPENSE
Dominion North Carolina Power	)	

BY THE COMMISSION: Pursuant to the Commission's November 3, 1998 Order Approving Guidelines (Guidelines) in Docket No. E-100, Sub 56, Duke Energy Carolinas, LLC (DEC or the Company) filed its Decommissioning Cost Study Reports on April 9, 2014. In connection with that filing, DEC filed its Decommissioning Cost and Funding Report (Report) on October 10, 2014. Pursuant to the Guidelines, the deadline in which to file discovery requests on the Company concerning the details of the new studies and related expense/revenue calculation is January 8, 2015, and the Public Staff's report is due April 8, 2015.

On December 23, 2014, DEC filed a letter stating that the Report filed on October 10, 2014, indicates that based on reasonable assumptions including but not limited to, decommissioning costs, inflation rates, taxes, and interest rates, the Company is now projecting that the current decommissioning trust funds balances will be sufficient to fully fund decommissioning the Company's nuclear units when such time comes. The Company stated that recently, the Nuclear Decommissioning Trust has experienced investment returns significantly higher than what is expected over the long-term. DEC stated that although the assumptions used in the Report are based on the Company's current estimate of future investment returns and cost estimates, actual results may vary significantly. Depending on returns and changes in cost escalation rates, future funding reports could show very different results.

However, based on the Report, the Company stated that it is reasonable to propose eliminating the amount of nuclear decommissioning expense included in current rates. The Company proposed to decrease rates to correspond with the rate changes planned for July 1, 2015, as ordered in Docket Nos. E-7, Sub 1058 and M-100, Sub 138 to reflect rate changes required by North Carolina House Bill 998 (S.L. 2013-316). The Company requested that the Commission approve deferring the corresponding revenue amount included in current rates for nuclear decommissioning costs using a regulatory liability account until such time as it will be refunded. On an annual basis, the Company anticipates that the rate change will equate to approximately 26 cents per month for an average residential customer. The Company requested that the Commission issue an Accounting Order effective January 1, 2015, authorizing such deferral until the time of the planned rate change. During that time, the Company stated its intent that the regulatory liability account accrue the net-of-tax overall rate of return as set in the Company's most recent rate case. Finally, the Company expressed its willingness to extend the Public Staff's discovery period, as the Company has requested an extension of its time to respond to certain requests sought by the Public Staff.

In the Commission's Order Granting General Rate Increase issued on September 24, 2013, in Docket E-7, Sub 1026, the Commission approved a stipulated reduction to DEC's annual nuclear decommissioning expense from approximately $35 million to approximately $14.6 million on a North Carolina retail basis. Pursuant to a provision in the stipulation approved by the Commission's Order, the Public Staff agreed that it would not oppose a deferral request by the Company for any changes in decommissioning cost and funding requirements based on future decommissioning studies filed with the Commission until the Company's next rate case.

The Public Staff presented this matter at the Commission's Regular Staff Conference on January 12, 2015. The Public Staff stated that it has reviewed the Company's request, agrees with DEC's deferral accounting proposal, and recommends approval. The Public Staff noted, however, that the 26 cents per month rate changed reflected in the Company's letter is only the reduction in the approximately $14.6 million of North Carolina retail nuclear decommissioning expenses and does not include the effect of the proposed deferral accounting. The Public Staff proposes that DEC also refund the amount deferred during the January 1, 2015, through June 30, 2015, period over the 12-month period beginning July 1, 2015, including the accrued return on the deferred balance throughout the deferral and refund period. The Public Staff also noted that it is currently engaged in discovery with respect to the Report, and its conclusions regarding the Report and corresponding calculations may vary with that of the Company. The Company does not oppose the Public Staff's proposals. Therefore, the Public Staff recommended that the Commission's order approving DEC's request state that the amount to be refunded shall be subject to further order of the Commission.

Based on the foregoing, the Commission concludes that the Company's request should be approved, subject to the Public Staff's recommendations.

IT IS, THEREFORE, ORDERED as follows:

1. Effective January 1, 2015, the Company shall establish a regulatory liability account and defer the revenue amount that corresponds with the decommissioning expense included in its current rates until refunded to customers. The account shall accrue the net-of-tax overall rate of return as set in the Company's most recent general rate case.

2. Any refund shall include both the reduction in the amount of decommissioning expense and the effect of the deferral accounting, and shall be refunded over a twelve-month period. The amount to be refunded to customers shall be subject to further order of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of January, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner Jerry C. Dockham did not participate in this decision.

DOCKET NO. E-100, SUB 73

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Investigation of Changes Occurring in the	)	
Electric Utility Industry and the Regulatory	)	
and Policy Implications of Such Changes,	)	ORDER ADOPTING GUIDELINES
including Proposals for Innovative Rates	)	FOR JOB RETENTION TARIFFS
and Mechanisms, and Proposed Interim	)	
Guidelines for Self-Generation Deferral Rates	)	

BY THE COMMISSION: On January 21, 2014, the Commission issued an Order initiating a generic investigation into the appropriate guidelines for job retention tariffs. In particular, the Commission sought comments from interested parties regarding the appropriate eligibility criteria for participation in a job retention tariff, the appropriate method of cost recovery, and the criteria or benchmarks that should be employed for measuring or verifying that a job retention tariff has been effective in preserving jobs. The Commission requested initial comments by February 24, 2014, and reply comments by March 24, 2014.

On February 21, 2014, the Public Staff - North Carolina Utilities Commission (Public Staff) filed a motion for an extension of time to extend the time for filing comments and reply comments to March 10, 2014, and April 7, 2014, respectively. On February 25, 2014, the Commission entered an order granting the motion.

On March 27, 2014, the Public Staff filed a motion to extend the time to file reply comments to May 2, 2014, which the Commission granted on March 28, 2014. On February 24, 2014, the North Carolina Electric Membership Corporation (NCEMC) intervened in the proceeding without making initial comments. On May 27, 2014, the Public Staff filed a motion to extend the time to file reply comments to June 13, 2014, which the Commission granted on May 28, 2014.

On March 10, 2014, the following parties filed initial comments: Carolina Industrial Group for Fair Utility Rates II and III (CIGFUR), the Public Staff, Carolina Utility Customers Association, Inc. (CUCA), Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress (DEP) filed jointly (DEC/DEP), the United States Department of Defense and all other Federal Executive Agencies (DoD/FEA), the Kroger Co. (Kroger), Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), the North Carolina Sustainable Energy Association (NCSEA), and the NC Waste Awareness and Reduction Network (NC WARN). On March 11, 2014, the Commercial Group filed initial comments, which the Commission finds and concludes were timely filed. On June 13, 2014, CIGFUR, Public Staff, CUCA, Duke, DoD/FEA, DNCP, and the Commercial Group filed reply comments.

SUMMARY OF COMMENTS

INITIAL COMMENTS

CIGFUR

Before addressing the three areas requested for comment, CIGFUR provides background of the current status of industrial customers in North Carolina. Specifically, CIGFUR indicates that "North Carolina is steadily losing skilled, high-wage jobs of the type typically offered by large, capital intensive employers." CIGFUR cites Dr. Julius Wright's study and testimony provided in DEP's last general rate case that "industrial electric sales and the number of industrial customers have been persistently declining over the past fifteen or so years." *See* Julius A. Wright, The Economic and Rate Implications from an Electric Utility's Loss of Large-Load Customers (hereinafter, "Wright Study") (filed March 14, 2013, in Docket No. E-2, Sub 1023) (DEP Rate Case). CIGFUR provided further statistics from the Wright Study as follows:

> DEP's industrial sales decreased by 28% from 1997 to 2011; Duke Energy Carolinas, LLC's ("DEC") industrial sales plummeted 33% from 1998 to 2011; Dominion North Carolina Power's industrial sales plunged about 40% from 1996 to 2012.[1] Correspondingly, North Carolina has lost over 200,000 manufacturing jobs over the last ten years.[2] These lost industrial jobs hurt North Carolina's economy especially hard due to the uniquely high multiplier effect industrial concerns exhibit: for every new (lost) employee at an industrial facility, there are 1-3 additional new jobs created (lost) in the region; there is region-wide increase (loss) of approximately $500,000 per year in economic output; and there is a region-wide increase (loss) of $200,000 to $350,000 in employee earnings.

Wright Study, p. 3. CIGFUR states that these lost sales and customers represent lost contribution to the utility's fixed costs that other customers must bear. "For example, a loss of just 5% of DEP's large general service class load would, all things being equal, result in a 0.40% increase in residential electric rates. After giving effect to the multiplier, the residential rate impact would increase to 1.23%." Because electricity costs constitute one of the most important considerations for the location of industrial customers, "if another state or country can offer lower electric rates at similar reliability, large industrial customers, in order to remain competitive, must make the rational economic decision to redeploy their capital accordingly, by ramping down activity in the higher priced jurisdiction or even resiting production locations." CIGFUR supports a job retention tariff (JRT) targeted to customers who will make the largest difference in influencing employment levels and positively impacting other ratepayers and the local economy.

With this background, CIGFUR addresses the three areas in which the Commission sought comment regarding the creation of potential guidelines: 1) appropriate eligibility criteria for

[1] NCUC Docket No. E-2, Sub 1023, O'Sheasy: Vol. 3, 66:3–10; O'Sheasy Direct Ex. 6; NCUC Docket No. E-7, Sub 1026, Vol. 7, 292:21–23; Initial Comments of Dominion North Carolina Power, p. 2, NCUC Docket No. E-100, Sub 73 (filed Feb. 24, 2014).

[2] NCUC Docket No. E-2, Sub 1023, O'Donnell: Vol. 3, 225:27–28.

participation in a JRT, 2) appropriate method of cost recovery, and 3) criteria or benchmarks that should be employed for measuring or verifying that a JRT has been effective in preserving jobs.

With respect to the eligibility criteria, CIGFUR recommends that the guidelines should define a customer eligible for service under the JRT as follows:

> An Eligible Customer shall be defined as any customer taking service at participating facilities (A) with a demand of 3 MW or greater, and (B) (i) which uses electric power as a principal motive power for the manufacture of a finished product, the extraction, fabrication or processing of a raw material, or the transportation or preservation of a raw material or a finished product, or (ii) whose annual cost of electricity exceeds thirty percent (30%) of that facility's cash annual operating cost and is located on land zoned for industrial use.

CIGFUR recommends that a determination of eligibility should not require a showing of financial distress. CIGFUR argues that such a requirement would inhibit participation in a JRT. CIGFUR indicates that a company does not need to be in financial stress to move to another state with more favorable operating costs.

With respect to cost recovery, CIGFUR posits that cost recovery from ratepayers is appropriate as long as the participating customers' discounted rates exceed the variable cost of service and make some contribution to fixed costs. The reason is that a JRT is designed to result in job retention and lower rates for all customer classes and therefore is in the public interest. CIGFUR states that the appropriate time to recover the cost of a JRT is through a rate case, as long as the cost of a JRT is allowed to be deferred as a regulatory asset.

Lastly, with respect to measurement and verification (M&V) benchmarks, CIGFUR states that benchmarks should generally be tied to employment levels. However, CIGFUR notes that some flexibility should be built into the reporting guidelines to account for unemployment declines not due to a discretionary decision of a participating employer. CIGFUR suggests that participating customers provide a confidential annual report to the utility indicating the employment levels. If the employment level declines by a certain percentage, for example, 5%-10%, the customer would be automatically removed for the JRT unless it demonstrates to the utility that (1) the decrease is temporary; (2) the decrease would have been greater without the JRT; or (3) the decrease is due to an event beyond the customer's reasonable control, such as a loss of a major contract. CIGFUR recommends that the Public Staff has the right to review and inspect the reports as long as the confidentiality is maintained. CIGFUR urges that if the Commission requires the filing of the report that the report be filed under seal. CIGFUR suggests that the Commission receive on an annual basis a confidential list of participating customers and an aggregated and de-identified report of the employment levels of all customers served under the JRT.

PUBLIC STAFF

The Public Staff states that any JRT[1] should strike an appropriate balance between the costs and benefits to all customers to promote the public interest. The Public Staff stated that to accomplish such benefits, the JRT should be offered only to those customers for whom the discounted rate would prevent the loss of jobs and related electric load. The JRT should provide a discount no larger in amount and no longer in duration than necessary to retain jobs and load. The discounted rate should cover at least the marginal cost of serving the customers receiving the discount, including the marginal capacity cost, to ensure that customers not receiving the discount are not overly burdened and that customers receiving the discount are not unfairly advantaged.

The Public Staff recommends that the JRT should address the eligibility concerns cited by Public Staff witness James McLawhorn and the Commission in the DEP Rate Case. Any JRT guidelines should include a requirement that the tariff have meaningful, verifiable qualifications to establish that a particular customer or group of like customers is in need of a JRT and will use the discount in rates to retain jobs. The Public Staff argues that the requirements should include a demonstration of financial and managerial viability on the part of the customer receiving the discount.

The Public Staff provides provisions and requirements from other states that the Commission should consider in developing the guidelines. These include:

> affidavits confirming eligibility or need; service contracts; fixed terms; provisions ensuring that revenues exceed the incremental cost (including marginal capacity cost) to serve; proof of financial distress; a minimum peak demand; participation in an energy audit or in other energy conservation measures; and penalties or repayment if the contract is violated or load is not retained.

Lastly, the Public Staff recommends that the Commission seek input from the North Carolina Department of Commerce when developing the terms and criteria for guidelines for a JRT.

CUCA

Like CIGFUR, before providing comments on the Commission's request, CUCA provides background information on the need for a JTR. CUCA states that it is the policy of the State of North Carolina to stimulate economic activity and to create new jobs for the citizens of the State, as well as recruiting and attracting new business and industry to the State. A JRT would assist in achieving the State's policy. Further, CUCA argues that "too many of our homegrown businesses are being pushed ever closer to the precipice because of escalating energy costs." Loss of jobs means a loss of tax base. CUCA cites to Dr. Julius Wright's testimony in the DEP Rate Case where he stated that when an industrial job is gained or lost, there is a ripple or multiplier effect. Thus, industrial and manufacturing jobs are the kinds of jobs that support other jobs, such as fast food restaurants, grocery stores, etc. Lastly, CUCA notes Kevin W. O'Donnell's testimony in DEC's

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[1] The Public Staff, and other parties, refer to a possible job retention tariff (JRT) as an industrial economic recovery (IER) rider or a Job Retention Rider (JRR). For consistency purposes, when parties use the terms IER or JRR, the Commission shall convert that term to JRT for purposes of this order.

last general rate case (Docket No. E-7, Sub 1026) wherein he testified that if industrial sales were eliminated in the DEC region that rates for other customers would rise on average by 10.6% and in the last DEP rate case, the rates would rise by an estimated 8.1%.

With respect to providing comments on the requested issues, CUCA indicates that the rider should be narrowly focused on industrial customers and manufacturers due to the fact that they compete both nationally and internationally, where electric rates make a difference. CUCA suggests that one way to accomplish this goal would be to use the definition of "industrial" as provided by the Bureau of Labor Statistics in the eligibility criteria. CUCA suggests another definition to be added to the eligibility criteria is "manufacturing," and defining it as establishments engaged in the mechanical, physical or chemical transformation of materials, substances or components into new products. CUCA suggests that another eligibility criteria to use is a requirement that an eligible company’s average wage for its workers should be at least 1.2 times the minimum wage.

With respect to cost recovery, CUCA suggests that the JRT be tested as a pilot program with the ultimate review of the reasonableness of the costs to be determined at the utility’s next general rate case proceeding if a utility proposes to make it a permanent part of the utility’s rate structure. CUCA notes that if the utility chooses to offer to pay for some or all of the JRT at the utility’s expense, the Commission does not need to exercise as much analysis.

With respect to measurement and verification, CUCA cautions the Commission on creating too strict of an M&V program. CUCA suggests “that CUCA be allowed to file, on behalf of its members who request CUCA to do so on their behalf, one aggregated confidential Annual Certificate for each CUCA member, compiled by CUCA to maintain employer confidentiality, with the serving utility.” CUCA states that the annual certificate should not require detailed financial information because it would discourage participation. CUCA states that a reduction in employment should not be an automatic end to a JRT, but that the business should be allowed to offer explanations for the decline in employment. Lastly, CUCA urges that the utility should be allowed to make the initial determinations regarding whether or not the M&V standards have been met and thereafter file its own confidential Annual Report to be reviewed by the Public Staff.

DEC/DEP

In their initial comments, DEC/DEP indicate that industrial sales for both DEC and DEP have declined nearly every year since 1997 and 1998 respectively, and that when industrial load decreases, the fixed costs previously borne by those customers are passed onto other customer classes. DEC/DEP state that “the importance of large load customers [] has been recognized all over the country in the form of economic development and load retention tariffs in a variety of fashions.” DEC/DEP provide as Attachment B to their filing, examples of job retention tariffs and load retention/economic development tariffs. DEC/DEP conclude that the adoption of a JRT would be consistent with the Commission’s prior approval of economic development tariffs in North Carolina.

With respect to the eligibility criteria for a JRT, DEC/DEP recommend that the JRT should be targeted at industrial customers that have the greatest impact on the State’s economy and that a customer should have at least 12 months of operating experience with the utility. Some ways to narrow the pool of applicants is to exclude Retail Trade or Public Administration as classified by the Standard Industrial Classification (SIC) Manual, to focus on the size of the electric demand, to concentrate on the use made of the power, to determine whether the zoning of the customer is industrial, or to require that the customer's cost of electricity represents a material portion of the cash operating cost of the facility. DEC/DEP do not agree with any requirement of financial distress or the use of "free rider" screens as these types of requirements can discourage participation. DEC/DEP posit that the narrow crafting of the eligibility criteria can accomplish the same goals.

As for cost recovery, DEC/DEP urge that the participating customer continue to cover all of its variable costs as well as contributing to its fixed costs under a JRT. DEC/DEP contend that cost recovery should be permitted because job retention is in the best interests for all customers. DEC/DEP suggest that cost recovery could be proposed in either a rate case, along with a JRT meeting the Commission approved guidelines, or in the creation of a deferred regulatory asset until the utility's next rate case. DEC/DEP recommend that cost recovery should not have an impact over one percent on other customers in any given year.

For JRTs for which cost recovery is not sought from other customers (utility self-funded JRTs), DEC/DEP recommend that the Commission need not judge the program using the same criteria as there is "no harm" to other customers.

With respect to measurement and verification, DEC/DEP suggest that the participating customer be required to provide the utility with a confidential report indicating the status of employment compared to the previous year and that the customer will attempt to maintain employment levels.

DEC/DEP would compile the data from the customers' reports and on an annual basis file the "JRT Compilation" with the Commission. The JRT Compilation would provide an aggregated level of employment by all of the customers served under the JRT. DEC/DEP would monitor the individual JRT reports from the customers to confirm the effectiveness per customer. DEC/DEP suggest that for any customer that has reduced employment levels from the prior year beyond a reasonable attrition allowance (such as 2.5%) should be immediately removed from the JRT unless the customer can make a showing that the decrease in employment is temporary, the decrease in employment would have been greater without the benefit of the JRT, or the decrease is due to an event beyond the customer's reasonable control, such as the loss of a major contract. These reports to DEC/DEP should be available for inspection by the Public Staff, and the Public Staff should be able to challenge whether or not a customer remains on the JRT. DEC/DEP request that any individual JRT reports on a specific customer be made under seal as they contain commercially sensitive information.

DoD/FEA

The DoD/FEA urges that the eligibility requirements for any JRT not limit the tariff to industrial customers. DoD/FEA contends that this limitation provides a subsidy to customers that have no need for it while forcing other non-industrial customers who may also face budgetary issues to pay more. DoD/FEA contends such a JRT also carries a risk that it would reduce employment in large non-industrial customers through increasing energy costs to those customers.

DoD/FEA is one of North Carolina's largest employers. "DoD/FEA directly employs approximately 140,000 military personnel in North Carolina. DoD/FEA supports 540,000 jobs in North Carolina, $30 billion in state personal income, and $48 billion in gross state product," and 340,000 of those 540,000 jobs occur in the private sector. Overall, the North Carolina Department of Commerce estimates that DoD/FEA supports 10 percent of North Carolina's economy. Fort Bragg alone spends more than $70 million per year on utilities. Fort Bragg consumes more than 500 million kWh of electricity per year with a peak demand of 140,000 kW. Even a small increase in costs per kW to provide a subsidy to other customers would result in a significant increase in overall energy costs to a large consumer like DoD/FEA. DoD/FEA proposes that any rider should provide savings to large users who reduce system costs by recognizing and responding to system demands in the form of demand response programs.

DoD/FEA indicates that DEP currently offers its LGS-RTP-26 tariff, available to eighty-five of its largest customers, which allows those customers to reduce energy costs through demand response programs, and that most major industrial power customers are on the RTP tariff. Fort Bragg is capable of reducing its peak demand by as much as 40,000 kW during a system coincident peak, which would reduce the stress on Fort Bragg's substations and DEP's transmission systems and generators. DoD/FEA suggests that the JRT concept be developed to reduce utility costs for both the supplier and the major users, and/or that the LGS-RTP tariff be modified to allow major users to reduce costs more substantially, through demand response programs, as opposed to providing a subsidy to one small class of customers. DoD/FEA states that the current RTP rate structure recognizes incremental energy use, but not capacity. Fort Bragg has untapped onsite generation and demand response capability that can be used to avoid new generation and transmission.

KROGER

Kroger opposes any JRT and recommends that the Commission reject any proposal on the grounds that such rates have no basis in cost-of-service regulation and violate G.S. 62-131. Kroger argues that the Commission specifically ordered that SIC code-based rates be phased out in Docket No. E-7, Sub 989, and that the JRT will renew these cross-subsidies.

DNCP

DNCP notes that its experience regarding the loss of industry and industrial jobs in its service territory is similar to the other utilities. Specifically, from 1996 to 2012, the number of industrial accounts taking service on DNCP's non-residential rate schedules has decreased by approximately 40%. Excluding Nucor Steel Hertford, industrial load has similarly decreased. DNCP is generally supportive of a JRT and guidelines to implement such a tariff.

DNCP agrees with Duke that the JRT should be limited to industrial customers. DNCP indicates that it has not seen a reduction in its commercial, governmental and residential customers, like it has seen with its industrial customers, indicating a distinction exists in need for the tariff. DNCP also urges that flexibility be maintained and that the guidelines not be too narrowly focused.

However, if the Commission chooses not to allow for a broad-based tariff, DNCP supports the following guidelines:

1- Determining which industrial customers to include should be determined on a utility by utility basis in response to the specific proposal.

2- A single account should not be able to receive service under both an economic development rate rider and a JRT. To allow both rates would allow a “double-benefit” funded by other ratepayers.

3- A rider incentive should not exceed five years.

With respect to cost recovery, DNCP asserts that a JRT should be revenue-neutral to the utility. DNCP does not find that Duke’s proposal to recover the revenue deficiency through a cents-per-kWh charge applied to all customer classes to be unreasonable as long as the customer pays its variable costs plus a fair and equitable contribution to the recovery of the utility’s fixed costs. DNCP asserts other approaches might be reasonable as well. DNCP proposes that establishing a JRT in a general rate case is appropriate. DNCP also asserts that allowing for approval outside a rate case might be appropriate under certain circumstances, but if approved outside of a rate case, a mechanism for cost recovery should be made concurrently.

DNCP does have concerns about engaging in decision-making on a customer’s eligibility and continued participation in a JRT and recommends clear rules be developed regarding customer eligibility and ongoing job retention obligations. DNCP recommends that the customer should be required to state a reasonable expectation to maintain current employment levels and/or some level of need for this rate relief. Lastly, reporting requirements should be established by the specific utility.

NCSEA

NCSEA recommends the following three eligibility guidelines:

1. Any guidelines established should require that a utility filing a job retention tariff include as part of the application a good faith estimate of any anticipated cost-shift and a quantification of expected benefits.

NCSEA argues that the Commission has previously stated that a JRT is largely a public policy issue in which the Commission must balance the costs and benefits. Therefore, any application should provide a good faith estimate of any anticipated costs, including cost-shifts, and benefits, including the identification of classes receiving benefits. NCSEA discusses the benefits of cross-subsidies in the context of net metering and argues that cost-shifts are only part of the story in ratemaking. The other half of the story is the benefits provided by suggested cost-shifts.

2. Any guidelines established should require that a utility filing a job retention tariff include as part of the application a statement indicating that the proposing utility has no reason to believe the tariff will not pass constitutional muster with regard to the dormant Commerce Clause.

NCSEA argues that, because the Commission in a 1994 order regarding economic development rate guidelines stated that those guidelines leave unaddressed the goal of retaining load due to retail wheeling and competition between utility concerns, the Commission has already foreseen that a request for a JRT could potentially involve interstate commerce. NCSEA states that the goal of job retention on its face seems to provide a direct commercial advantage to local business. Therefore, NCSEA requests that a utility make a statement in its application for a JRT that, to its knowledge, the tariff complies with the dormant Commerce Clause.

3. Any guidelines established should prohibit a utility filing a job retention tariff from conditioning customer eligibility on submission of proof that a viable, lower cost renewable energy or energy efficiency alternative exists that demonstrates the customer could leave or reduce its usage of the utility's system.

NCSEA requests that utilities not require the customer to prove, as a condition of eligibility, that the customer could leave the system or reduce its usage of the system through lower cost renewable energy or through an energy efficiency alternative. NCSEA states that such a requirement would be detrimental to employment in the clean energy industry.

NC WARN

NC WARN's comments in large part reference the deficiencies in the proposed DEP IER Rider in Docket No. E-2, Sub 1023. NC WARN states that there is a more in-depth record in the DEP Rate Case. NC WARN asserts that the primary impetus for the current docket stems from settlement agreements made between DEP, DEC, CUCA and CIGFUR in the merger dockets, Docket Nos. E-7, Sub 986 and E-2, Sub 998. NC WARN contends that both CUCA and CIGFUR agreed not to oppose the merger in exchange for DEC and DEP supporting an industrial discount rider. NC WARN contends that to meet their merger commitments to the industrial customers, DEC and DEP proposed the IER riders, a five-year pilot rate discount for industrial customers, in their respective rate cases.

NC WARN outlined arguments made in the DEP Rate Case that were specific to that proposal. However, within the arguments made, NC WARN points to several factors that the Commission should consider when determining a load retention rate. NC WARN suggests that the tariff should have: (1) a requirement of an affidavit confirming eligibility or need; (2) a specific service contract; (3) proof of financial distress; (4) analysis showing that the discount is set at the necessary minimum; (5) a requirement to implement identified cost effective energy efficiency improvements following a facility audit; and (6) penalties or repayment for contract violations.

NC WARN questions whether the Commission has the authority to approve such a job retention program and suggests that instead of a JRT the Commission should focus on customers in each of the existing ratepayer classes who are most impacted by economic difficulties and examine which customers would be best assisted by rate discounts.

THE COMMERCIAL GROUP

In its initial comments, the Commercial Group first outlines that its members have a substantial positive impact on North Carolina's economy and that three of the top eight largest private employers are members of the Commercial Group. Collectively, its members employ over

100,000 North Carolina workers and support the employment of over 100,000 other North Carolina workers through the billions of dollars group members spend for merchandise and services in the State each year. The Commercial Group recommends that any job retention tariff should: 1) not unreasonably prefer or advantage any one set of ratepayers over other ratepayers, and 2) be narrowly tailored to meet job retention objectives.

The Commercial Group directs the Commission's attention to G.S. 62-140(a), which provides that no public utility shall make or grant an unreasonable preference or advantage to any person, or subject any person to any unreasonable prejudice or disadvantage. The Commercial Group argues that the terms of any JRT should not be similar to the IER proposed in the DEP Rate Case that the Commission rejected. In the proposed IER, the eligibility was linked to an industrial SIC code. The Commercial Group argues against the proposed rider by illustrating that under the IER, a bakery inside a Food Lion and a stand-alone bakery across the street would be treated differently based upon the SIC code. The Commercial Group recommends that the guidelines resemble the Business Incentive and Sustainability Rider for Northern States Power Company that was approved by the Minnesota Public Utilities Commission.

The Commercial Group recommends that standards for a JRT be more narrowly tailored than the proposed DEP IER. The Commercial Group argues that the DEP IER was overly broad in that it did not require a showing of financial hardship and it would have included small businesses that had an "industrial" classification. The Commercial Group urges more focused criteria so that valuable ratepayer funds are not wasted.

REPLY COMMENTS

CIGFUR

CIGFUR states that it joins in DEC/DEP's reply comments and incorporates them by reference and limits its reply comments to three discrete issues. First, the Commission possesses the authority to adopt guidelines for JRTs. In its initial comments, NC WARN questioned whether the Commission had statutory authority based upon the fact that G.S. 62-2 does not contain language regarding job retention or economic development. Therefore, NC WARN argued that these issues do not fall squarely within the scope of utility regulation.

CIGFUR argues that NC WARN's assertion is incorrect. CIGFUR states that the Commission is guided by considerations of the public interest and the General Assembly has given the Commission broad authority to regulate public utilities. CIGFUR cites to G.S. 62-2 (a), which states that "the availability of an adequate and reliable supply of electric power … to the … economy … of North Carolina is a matter of public policy." Also, within the policy section of Chapter 62, the statute imparts that the State is "to provide fair regulation of public utilities in the interest of the public." G.S. 62-2(a)(1). CIGFUR argues that JRT guidelines are intended to ultimately benefit all ratepayers and that this is in the public interest and within the Commission's authority.

CIGFUR further asserts that the North Carolina Supreme Court has confirmed the Commission's authority to approve rates intended to stimulate economic activity. See State ex rel. Utils. Comm'n v. Edmisten, 294 N.C. 598, 242 S.E.2d 862 (1978) (upholding approval of a surcharge to fund an exploration program to discover new sources of gas within North Carolina). The Court held that "[i]t was certainly within the authority of the Commission to determine that all North Carolina gas ratepayers would benefit from increased supplies of natural gas, both through assured availability and improvement in the State's economy." Id. at 611–612, 242 S.E.2d at 871.

CIGFUR further explains that the Commission has exercised this type of authority in the past. For example, the Commission has previously adopted guidelines for economic development rates in this docket, as well as Docket Nos. E-2, Sub 681 (Economic Development Rider); E-2, Sub 819 (Economic Redevelopment Rider); E-7, Sub 719 (Economic Redevelopment Rider); E-7, Sub 771 (Economic Development Rider and Economic Redevelopment Rider); E-22, Sub 384 (customer-specific rate, filed pursuant to Commission's guidelines for economic development rate, intended to encourage industrial company to build large facility in Eastern North Carolina); and G-9, Sub 407 (Economic Development Rider). Lastly, CIGFUR refers the Commission to DUPC Investigation Into Electric Loan Retention Tariffs, 253 P.U.R. 4th 98, 25 (Conn. 2006) ("A review of other jurisdictions shows that virtually every state has some type of an economic development incentive rate to promote business retention and economic growth."), to support the creation of a JRT in North Carolina.

CIGFUR urges that a JRT should be limited to industrial customers. CIGFUR reiterates the concrete definition of an Eligible Customer for a JRT that it provided in its initial comments and urges its inclusion in the guidelines. CIGFUR argues that industrial customers are uniquely situated and that to expand the JRT to non-industrial customers increases the expense of the program and disconnects the program from the policy justifications for it. First, industrial energy sales have declined over the past fifteen years. See Duke Energy Carolinas Integrated Resource Plan, pp. 13, 64–68, Docket No. E-100, Sub 137 (filed Oct. 15, 2013); Duke Energy Progress Integrated Resource Plan, pp. 13, 55–59, Docket No. E-100, Sub 137 (filed Oct. 15, 2013); Dominion Virginia Power's and Dominion North Carolina Power's Report of Its Integrated Resource Plan, p. 21, Docket No. E-100, Sub 137 (filed Aug. 30, 2013). Second, CIGFUR notes that industrial customers can display exceptional electric price elasticity. The data shows that large industrial customers will respond to electricity price signals in a significant way. Over a longer term (2–3 years), the data indicates that industrial customers will reduce electricity consumption by as much as 30% to 40% in response to a 10% increase in electricity prices, "a much more aggressive response to electric price changes than is exhibited by the commercial class of customers." Wright Study, pp. 11-12 Third, CIGFUR asserts that because of industrial customers' uniquely high multiplier effect and load factor, the retention of industrial jobs and load benefits all customers by boosting the North Carolina economy and absorbing a utility's fixed costs. These three factors, which are unique to industrial customers, support targeting the JRT to industrial customers. CIGFUR notes that no evidence has been provided to justify offering a JRT to other customer classes.

Lastly, CIGFUR recommends that the guidelines should not prevent a customer from receiving service under an economic development tariff and a job retention tariff. DNCP, in its initial comments, states that, if "more focused guidelines" are established, "[a] single account should not be able to receive service under both an [economic development rider] and [a JRT] at the same time." CIGFUR disagrees, stating that the rates accomplish two different goals: one is to attract new capital, jobs and load, and the other is to retain existing jobs and load. CIGFUR argues that including such a prohibition in the guidelines runs counter to DNCP's stated goal of "allowing each of the Utilities the flexibility to determine when and how to best support the goals of job retention and economic growth and competitiveness within their own services areas." In any event, CIGFUR argues that this decision is one that should be addressed in a utility-specific filing versus the guidelines.

PUBLIC STAFF

In its reply comments, the Public Staff indicates that on April 9, 2014, it convened a meeting of representatives of the parties for the purposes of discussing the various parties' positions and determining whether the parties could agree on any criteria that should be included in the guidelines. The Public Staff indicates that while total consensus was not achieved, the parties were able to agree generally that at a minimum, the following should be included in the guidelines:

A. The tariff application should include the following:

   i. Information regarding the group of customers that would be generally eligible to be considered for the discount and justification for targeting that specific group.

   ii. Specific eligibility criteria for the target group of customers to qualify for the discount and justification for the criteria – criteria must be designed to target job retention and must be reasonably related to retaining customer load. (The Commercial Group and Kroger would prefer language such as "criteria must be designed to achieve job retention and retain customer load." The Public Staff does not oppose this language).

   iii. Information demonstrating that the tariff is not unduly discriminatory and is in the public interest.

   iv. Information regarding how customer specific information should be treated for confidentiality purposes.

   v. Quantification of the maximum potential monetary exposure for other customers and how the applicant proposes to recover such costs.

   vi. A cost study to demonstrate that the discounted rate covers at least the marginal cost of energy and capacity for the target group based on characteristics broadly representative of the group.

B. A retention tariff shall not be made available to any customer that does not have at least 12 consecutive months of operating experience with the utility.

C. The availability of a retention tariff shall not exceed five years from approval of the tariff and cannot be extended. However, a utility may reapply for another retention tariff under the guidelines.

The Public Staff has some concerns regarding the JRT. One concern relates to suggested criteria that would allow participating customers on a JRT to remain on a JRT notwithstanding a failure to retain jobs or load if certain conditions are met. Although the Public Staff has concerns regarding this criteria, it suggests that this issue is best addressed in the context of a specific application for a specific JRT.

The Public Staff's second concern relates to the Commission's authority under Chapter 62 to base a rate differential on preserving jobs. The Public Staff posits that in order for a JRT to be just and reasonable and non-discriminatory, there must be a link between the tariff and maintaining jobs and load. This link allows for the Commission's authority as a loss of jobs, a loss of the related load and the associated revenue loss would have a negative impact on the electric rates of all other customers. The Public Staff urges that the guidelines should require that the utility specify the minimum level of load and number of jobs that must be maintained for a customer to be eligible for and remain on the tariff.

The Public Staff's third concern is free ridership. The Public Staff states that additional guidelines and filing requirements should be included in the Commission's guidelines to ensure that any JRT needed will avoid attracting free riders as much as possible so to not overburden other customers. The Public Staff attached proposed Guidelines and Filing Requirements for Job and Load Retention Tariffs as Exhibit A to its filing. The Public Staff's proposal utilizes some of the same requirements as those found in the Commission's guidelines for self-generation deferral rates and economic development tariffs, which the Public Staff maintains are similar in purpose.

The key points that the Public Staff addresses in Exhibit A are:

a. The guidelines should require a utility to show an urgent need for a discount to maintain jobs and load and that amount of the discount is no more than necessary.

b. The guidelines should require the customers receiving a discount sign a contract and that the contract should be filed with the application for the tariff. The contract should include the level of load and jobs the customer will agree to maintain, and termination and "clawback" provisions for failing to maintain the load and jobs. A contract requiring a "reasonable expectation" to maintain current employment levels is insufficient. The Commission's guidelines for economic development rates and self-generation deferral rates both require a contract, as do retention tariffs in other states. (For example, see the Duke Energy Kentucky, Inc.'s Rider DIR; Rider EDRR; Southern Indiana Gas and Electric Company's Rider ED; Southern California Edison's Rider EDR-R; the City of Riverside's Schedule BR; Alliant Energy's Economic Development Program Rider; and the Pacific Gas and Electric's tariffs attached to DEC/DEP's comments in this docket.) The contract should include a provision stating that the customer is eligible under the terms of the tariff, that the customer is in need of the discount to achieve job and load retention, and that the customer will use the discount to do so.

c. The discount offered under the retention tariff should be a declining discount. Like the economic development tariff, the retention tariff is intended to be a temporary discount.

d. A customer should not be permitted to be on a retention tariff and an economic development tariff at the same time. The Public Staff believes that the tariffs have similar purposes, and allowing a customer to take advantage of both would amount to "double dipping" for undertaking the same activity.

e. The utility should be required to provide a customer by customer analysis and data every year (i.e., no aggregated data). This information may be filed confidentially.

f. The guidelines should provide that a utility may only recover the costs of a retention rider in the context of their incurrence in a historical test year in a general rate case. The Public Staff disagrees with DEC and DEP that a utility should be permitted to defer the costs of the tariff until a general rate case. If a utility would not have been allowed to defer revenues lost due to loss of load, it should not be allowed to defer revenues lost due to a discount aimed at retaining that load.

g. Public Staff scrutiny of a pilot tariff is important, whether funded with shareholder money or ratepayer money.

Lastly, the Public Staff indicates that the Economic Investment Committee within the Department of Commerce oversees Job Development Investment Grants (JDIG) for the State. JDIG recipients must execute a contract that specifies their job creation and retention obligations, and termination provisions for a default. A copy of the form contract, provided to the Public Staff from the Department, is attached to its filing as Exhibit B for the Commission's reference.

CUCA

CUCA mainly reiterates its initial comments filed on March 10, 2014, and those comments will not be repeated. CUCA did, however, redefine from its initial comments, its definition of the "manufacturing" process for purposes of customer eligibility. In its reply comments, CUCA supports a requirement that the customer engage in a "manufacturing process – that is, a process which converts raw or partly finished materials into a different end product for sale or shipment."

CUCA supports the general concept of DEC/DEP's initial comments that the initial guidelines for a JRT for industrial or manufacturing customers should be as relatively open-ended as possible and that more detailed requirements are appropriately reviewed after the filing of a specific tariff proposal.

CUCA agrees generally with DNCP's comments. CUCA supports DNCP's position "that any necessary Measurement and Verification provisions should be omitted from the initial, general guidelines established by the Commission and, instead, should be deferred as a response to a specific [JRT] filing."

CUCA supports the four "General Areas of Agreement" regarding the initial guidelines for JRTs that emerged out a meeting initiated by the Public Staff. CUCA does not support the initial comments of the Public Staff stating that the Public Staff's suggestions would "kill any chance of a successful IER or JRT ever being filed or implemented." CUCA disagrees that proof of financial need be required to be eligible for a JRT. CUCA states that such a provision would prevent most industrial customers from even applying for the tariff. Furnishing financial information and business strategies could result in various negative outcomes such as competitive losses, loss of market share, loss of stock price and required filings at the SEC. CUCA asserts that any term of a JRT should be for a term certain and not until the tariff is no longer necessary as proposed by the Public Staff. CUCA states that the "guidelines" should be "inviting" to industrial customers and that the more difficult questions of cost recovery and measurement and verification should be determined in in the specific tariff proceeding.

CUCA responds to the Commercial Group's free rider argument by stating that if the Commission requires financial need to reduce free ridership, then the Commission will be eliminating most of the otherwise eligible applicants because most applicants would not submit such confidential financial information. CUCA responds to NC WARN's initial comments by stating that NC WARN's concerns are not appropriate for consideration in terms of the general guidelines, but are best determined when a specific tariff is filed. Furthermore, with respect to any issue of discrimination, CUCA states that Chapter 62 does not prohibit any and all forms of discrimination, only "unreasonable" discrimination. CUCA states that as long as the Commission has a rational nexus regarding the rate structure and any different treatment among classes, the Commission's actions are not prohibited.

CUCA states that NCSEA's comments regarding estimating any costs shifts and concerns regarding the dormant Commerce Clause are more appropriate once a specific JRT is filed versus during the establishment of the guidelines for a tariff phase.

DEC/DEP

DEC/DEP support the guidelines generally agreed upon by interested parties during the meeting the Public Staff initiated to find consensus. DEC/DEP further generally agree with DNCP's initial comments, which can be summarized as follows: (1) limiting a job retention rider does not unfairly disadvantage other customer classes; (2) the Commission should allow utilities to consider developing proposals focused on retaining and expanding industrial jobs in NC; (3) supporting the opportunity to propose a rider to target job retention and incentivize economic development within a customer class; (4) a single customer account should not receive service under both an economic development rate and JRT offering; and (5) that a class-based JRT incentive should not exceed five years (absent extenuating circumstances as approved by the Commission). As to cost recovery, DEC/DEP agree with DNCP that (1) a cents-per-kWh charge to all customer classes is not unreasonable, provided companies receiving an incentive pay variable costs plus a contribution to the recovery of the utility's fixed costs; (2) it is logical that a JRT proposal and cost recovery for such be made within a general rate case, but a utility should be allowed to file for approval of a JRT outside a general rate case should circumstances warrant; and (3) there needs to be a clear mechanism providing for current and future recovery of costs associated with a JRT incentive. As to measurement and verification, DEC/DEP share DNCP's concerns about a utility having to engage in discretionary decision-making about customers' eligibility for and continued participation in a JRT. DEC/DEP agree with DNCP that reporting requirements should be established on a utility-by-utility basis at the time of the JRT proposal.

In response to CUCA and CIGFUR's initial comments, DEC/DEP state that their respective proposed eligibility criteria are examples of how a utility could structure its tariff application and that the "Guidelines" that the parties generally agreed to in the meeting convened by the Public Staff are broad enough to encompass these examples. DEC/DEP agree with CUCA and CIGFUR's concern that a showing of financial stress not be required for eligibility. DEC/DEP state that "disclosing such information could violate securities laws, constitute contract default, and ultimately make it more costly, not less costly, for employers to operate and to retain jobs." DEC/DEP add,

> that providing such information even on a confidential basis does nothing to limit this concern, because a mere expression of financial distress, even if confidential, could trigger customer requirements to disclose such information to their lenders and customers, such as customers or lenders who require contractual liquidity provision for supply and purchase agreements and banking and guarantor agreements or other financial instruments.

DEC/DEP state that this possibility "could eliminate or exceed the benefit proposed under a JRT." DEC/DEP state that their impression after the meeting of all parties is that this issue has been resolved.

DEC/DEP agree with both CUCA and CIGFUR that cost recovery should be from all ratepayers and that if approved outside a rate case, deferral of the costs should be allowed until the next rate case. DEC/DEP do not agree that a determination of the reasonableness of the costs can be simply deferred. Rather, DEC/DEP state that any approval for a JRT should specifically detail the criteria that should apply in consideration for cost recovery in a subsequent rate case and that costs should not be disallowed in a rate case based upon policy arguments that were not raised in the JRT approval proceeding outside the rate case or addressed in the Commission's order approving a JRT outside of a rate case.

As to measurement and verification, DEC/DEP do not agree with CUCA that the utilities should decide whether an applicant has provided sufficient information to support the continuation of the JRT. DEC/DEP state this is a subjective determination better made by the Public Staff or Commission or some other third party. DEC/DEP support CUCA and CIGFUR's position on the confidentiality of company specific information. DEC/DEP further agree that they would remove any customer from a JRT if the customer failed to report as required or failed to provide an adequate explanation for any decline in employment levels. DEC/DEP reiterate that this determination regarding whether a company has provided an adequate explanation for a decline in employment should be made by the Public Staff or the Commission.

In response to the Commercial Group and Kroger's initial comments that a JRT that limits eligibility to industrial customers is wrong and unlawful, DEC/DEP reply that the Commission has full authority to grant a JRT and that it can be structured to be non-discriminatory. North Carolina General Statute Section 62-140 only prohibits unreasonable or unjust discrimination among classes of customers. See <u>State ex rel. Utils. Comm'n v. Bird Oil Co.</u>, 302 N.C. 14, 22, 273 S.E.2d 232, 237 (1981)("in establishing rates, th[is] statute plainly prohibits (1) unreasonable preferences, (2) unreasonable advantages, (3) unreasonable prejudices, (4) unreasonable disadvantages and (5) unreasonable differences"). DEC/DEP further reference <u>State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc.</u>, 323 N.C. 238, 252, 372 S.E.2d 692, 700 (1988) (holding that where non-cost factors justify differing rates for individual customer classes, the rates are not unreasonably discriminatory). DEC/DEP find that the public interest and the benefits arising out of a JRT provide sufficient justification for the JRT. DEC/DEP refer to several Commission dockets which approved economic development riders and opine that JRTs are a reasonable extension of these currently-approved economic development riders. See Order Approving Revisions, Docket Nos. E-2, Sub 681, E-2, Sub 819 (Dec. 14, 2006) (approving DEP's revised Economic Development Rider ED and Economic Redevelopment Rider ERD); Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (Sept. 24, 2013) (approving DEC's Rider EC (NC) Economic Development and Rider ER (NC) Economic Redevelopment); Order Approving Revisions, Docket Nos. E-2, Sub 681, E-2, Sub 819 (Dec. 14, 2006).

In addition, DEC/DEP disagree with the Commercial Group that the JRT should be tailored to only benefit customers in financial distress. DEC/DEP argue that profitable companies lay off employees or move operations, thus the question is not whether the company is going out of business, but rather whether the company is going to eliminate jobs or move jobs elsewhere. Either way, DEC/DEP argue that this issue is more appropriately determined at the time a specific JRT is filed. DEC/DEP further state that,

> unfortunately for a job retention objective of enabling a significant jobs impact while containing the cost impact upon others in a reasonable manner (i.e. getting the biggest bang for a reasonable buck) and being implementable, pragmatic qualifications may permit some non-target customers to participate yet screen out some other justifiable candidates.

DEC/DEP remind the Commission that "[t]he potential for over- or under-inclusiveness parallels a long-standing, inherent tension between the ratemaking goals of elimination of cross-subsidization and simplification of rate structure. See State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 424, 429, 230 S.E.2d 647, 650 (1976)." DEC/DEP assert that any proposed eligibility criteria will strike the appropriate balance to provide benefits to the citizens of North Carolina.

In its initial comments, NCSEA made the following requests:

1. Any guidelines established should require that a utility filing a job retention tariff include as part of the application a good faith estimate of any anticipated cost-shift and a quantification of expected benefits;

2. Any guidelines established should require that a utility filing a job retention tariff include as part of the application a statement indicating that the proposing utility has no reason to believe the tariff will not pass constitutional muster with regard to the dormant Commerce Clause; and

3. Any guidelines established should prohibit a utility filing a job retention tariff from conditioning customer eligibility on submission of proof that a viable, lower cost renewable energy or energy efficiency alternative exists that demonstrates the customer could leave or reduce its usage of the utility's system.

DEC/DEP state that they do not oppose condition (3); oppose condition (2) as unnecessary; and partially agree with condition (1) in that DEC/DEP do not oppose providing a good faith estimate of costs, but state that there is no way to quantify the benefits for a multiplier effect in the economy.

With respect to the dormant Commerce Clause issue, NCSEA suggests that a JRT might on its face provide a direct commercial advantage to local business creating a constitutional violation. NCSEA's fix for this is to require the utility to state in an application for approval of a JRT that to its knowledge, the JRT does not violate the dormant Commerce Clause. DEC/DEP respond that this requirement is unnecessary because any JRT will comply with the dormant Commerce Clause. DEC/DEP argue that a JRT does not burden or restrict interstate commerce. Further, if a JRT impacts interstate commerce, such impact is merely incidental and greatly outweighed by the local benefits of such a tariff. See Pike v. Bruce Church, Inc., 397 U.S. 137 (1970) ("Where the statute regulates even-handedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits."). DEC/DEP state that retaining jobs in North Carolina is a legitimate interest of the State which outweighs any incidental impact that the JRT has on interstate commerce. Lastly, DEC/DEP provide that other utility commissions have adopted JRTs, and, thus, any JRT would not be giving North Carolina an economic edge over other states, but would merely allow North Carolina to keep pace with these other states.

Lastly, DEC/DEP state that NCSEA's comments regarding cross-subsidies and net metering is "curious and misplaced."

DEC/DEP state that DoD/FEA's comments regarding the modification of large users' tariffs to reduce costs through demand response is not appropriate for this docket. DEC/DEP argue that "demand response is allowed and encourage in response to RTP hourly rates." In response to DoD/FEA's statement that any JRT should include military bases, DEC/DEP agree to discuss whether a JRT specific to military bases could be designed, but insisted that the DoD/FEA should not be included in any JRT aimed at large private employers. Lastly, DoD/FEA expressed a need to prevent customers under a JRT who have laid off workers from being able to re-qualify under newly reduced employment levels. DEC/DEP agree that preventing customers who have been removed from a JRT from reapplying might be appropriate under certain circumstances, but should be determined on a case by case basis.

DEC/DEP counter NC WARN's assertion that DEC/DEP do not care about a JRT, and that DEC/DEP are only fulfilling a promise made during the merger. First, DEC/DEP refer the Commission to Mr. Newton's testimony in Docket No. E-2, Sub 1023, where he stated that DEC/DEP believe that industrial and large commercial customers are of such importance to the State they agreed to seek such relief and that nothing is untoward about the agreements. Second, those settlement agreements are irrelevant to this docket.

Public Staff requested in its initial comments that any JRT should be offered only to customers for whom the discounted rate would prevent loss of jobs and electrical load and that the discount should be no greater in amount or longer in duration than necessary to accomplish job and related load retention. DEC/DEP respond stating that precision cannot be accomplished and that the Commission should balance any condition for eligibility with the impact of that condition upon the administration of a JRT and whether the condition will dissuade customer participation.

The Public Staff also recommended that the Commission look to the guidelines and filing requirements adopted for self-generation deferral rates and economic development rates when determining the guidelines for a JRT. DEC/DEP state that those guidelines should only be used as a data point. DEC/DEP suggest that more general qualifications criteria as compared to the other guidelines are appropriate for a JRT.

Finally, DEC/DEP state that they did not reply to many more specific comments of the parties as those comments are more appropriately addressed when a specific tariff is filed for approval.

DoD/FEA

In its reply comments, DoD/FEA argues that no evidence has been provided that shows any connection between North Carolina energy costs and lost industrial jobs. Without this evidence, any JRT would be an impermissible, discriminatory subsidy. DoD/FEA suggests that an alternative to the JRT is to bolster demand response and increase Demand Response Automation (DRA) programs. DoD/FEA provides two options as an alternative to the JRT:

> 1. A system coincident peak rider can be added to the RTP-TOU tariff based on the historical summer and winter peaks. The contract demand level would be reset by the customer demand at the time of the system peak.
>
> 2. Allow major users who have opted out of the DSM/EE program to participate in the DRA program. Most of the major users who opted out of the DSM/EE program did so because they had already invested in energy efficiency and demand side management. Therefore, the capital investment objectives of the DSM/EE legislation to reduce system demand had been met. However, the on-going incentives to reduce system stress during peak periods can be improved with the proper incentives. Since the major users are on the RTP-TOU tariff, they get price signals for normal supply and demand situations. They can provide more value for emergency situations as defined under the proposed DRA that separate emergency and curtailable situations.

DoD/FEA states that more aggressive demand response programs may produce the same results or better results as any JRT.

DNCP

DNCP supports the guidelines generally agreed upon by interested parties during the meeting Public Staff initiated to find consensus. Specifically, DNCP agrees to the following:

A. The tariff application should include the following:

   1. Information regarding the group that would be generally eligible to be considered for the discount and justification for targeting that specific group.

   2. Specific eligibility criteria for the target group of customers to qualify for the discount and justification for the criteria – criteria must be designed to

target job retention and must be reasonably related to retaining customer load.

3. Information demonstrating tariff is not unduly discriminatory and is in the public interest.

4. Information regarding how customer specific information should be treated for confidentiality purposes.

5. Quantification of the maximum potential monetary exposure for other customers and how the applicant proposes to recover such costs.

6. A cost study to demonstrate that the discounted rate covers at least the marginal cost of energy and capacity for the target group based on characteristics broadly representative of the group.

B. A retention tariff shall not be made available to any customer that does not have at least 12 months of operating experience with the utility.

C. A retention tariff approved under the guidelines shall not exceed five years from approval of the tariff and cannot be extended. However, a utility may reapply for another retention tariff under the guidelines.

THE COMMERCIAL GROUP

In its reply comments, the Commercial Group proposes the following specific guidelines:

1. Eligibility should not be based on any unreasonable classification or distinction among ratepayers, such as an SIC code.

The Commercial Group reiterates its initial comments that the SIC code should not be used to determine eligibility and to do so amounts to unlawful rate discrimination. Rather, the Commission should follow DoD’s suggestion of urging the utilities to create rate mechanisms that encourage large users to save on electric bills.

2. The utility should first demonstrate that the ratepayer(s) targeted to receive an electric rate discount need(s) the discount to preserve jobs, and will use that discount to preserve jobs.

The Commercial Group requests that any JRT should be narrowly tailored. The Commercial Group states that in their initial comments, the pro-industrial advocates merely repeat the same general information that was submitted in support of DEC and DEP’s IER proposals that the Commission has already rejected, and that no evidence has been presented to support broad subsidies.

3. The utility proposing a job retention tariff should self-fund at least 50 percent of the tariff discount.

The Commercial Group is encouraged by the fact that DEC/DEP may potentially self-fund JRTs, and suggests that a hybrid option should exist as well where the utilities partially fund the JRT.

DISCUSSION AND CONCLUSIONS

Based upon the comments provided in this docket, the Commission supports the adoption of guidelines and filing requirements for job retention tariffs. The Commission finds the approval of a JRT is a matter of sound ratemaking policy to address the undisputed decline in industrial sales in North Carolina. When DEC/DEP initially filed for approval of an IER in their respective rate cases, North Carolina was experiencing a significant loss of industry and a rise in unemployment. The Commission did not have guidelines in place to assess any type of JRT and the parties in the DEP Rate Case could not find consensus surrounding adoption of the IER. The Commission finds that the adoption of these JRT guidelines will assist all parties involved with the creation of a properly designed JRT to benefit all ratepayers. A JRT's objective is to stem further loss of industry, industrial production and industrial jobs from a utility's service area. The Commission has previously approved economic development riders. Commissions in other states have approved such incentive rates to promote specific economic or social objectives for the benefit of its citizens, making such tariffs within the public interest.

As part of its consideration of whether to approve a JRT, the Commission requested and the parties provided comments on three areas related to the creation of the guidelines: eligibility, cost recovery, and measurement and verification. The Commission has reviewed the comments and has incorporated these comments into the development of the guidelines. Comments outside of the scope of the request will not be addressed herein.

Eligibility

The Commission agrees with CIGFUR and CUCA that a company should not be required to show financial distress to be eligible for a JRT. The Commission shares DEC/DEP's concerns that "disclosing such information could violate securities laws, constitute contract default, and ultimately make it more costly, not less costly, for employers to operate and to retain jobs." Further, the Commission finds informative DEC/DEP's statement "that providing such information even on a confidential basis does nothing to limit this concern, because a mere expression of financial distress, even if confidential, could trigger customer requirements to disclose such information to their lenders and customers, such as customers or lenders who require contractual liquidity provision for supply and purchase agreements and banking and guarantor agreements or other financial instruments." Although the Commission agrees that a showing of financial distress should not be required, the Commission finds that some documentation from a customer requesting service under a JRT could be helpful to combat free ridership. An example of such a documentation requirement is for a utility to require a JRT applicant to provide it with documentation tending to show that the customer's load is at risk of loss, such as documentation that the utility has reason to believe the customer is communicating with other utilities. However, this issue regarding exactly what type of documentation a JRT should require is best determined once a specific JRT has been filed by a utility.

The Commission agrees with the Public Staff that any JRT should strike an appropriate balance between its costs and benefits to all customers to promote the public interest. Both Kroger and the Commercial Group urge the Commission to prohibit eligibility based upon a customer's

Standard Industrial Classification (SIC). Further, the Commission values the Commercial Group's request that any future JRT be more narrowly tailored than the proposed IER in DEP's Rate Case so that valuable money is not wasted on free ridership. While not determining the exact eligibility criteria for a utility, the Commission supports efforts by utilities to craft the eligibility requirements that are narrowly tailored to meet the intended goals of maintaining jobs in the most economically efficient manner and agrees with Kroger and the Commercial Group that eligibility should not be determined by a SIC code. The Commission finds and notes, however, that creating eligibility criteria is not an exact science, and any eligibility criteria may be over-inclusive or under-inclusive. Therefore, although the Commission keeps an open mind regarding any JRT's eligibility criteria, the Commission agrees with the Wright Study that concludes that industrial customers or a subset of industrial customers may provide the most benefit for the least amount of cost. Industrial customers are unique from other customers in that they are not generally tied to any particular location and can more readily or easily relocate. An appropriate definition of customer may be CIGFUR's suggested definition of a customer. This definition appropriately screens out smaller customers, minimizing the cost of the JRT.

NCSEA requests that the guidelines require that a utility, in its application for a JRT, state that it sees no reason why it would violate the dormant Commerce Clause. Any proposed JRT will either be constitutional or not under a dormant Commerce Clause analysis. Therefore, requiring the utility to state that it believes a JRT is constitutional in its application is unnecessary. Furthermore, in its reply comments, DEC/DEP assert that a JRT does not violate the dormant Commerce Clause; therefore, two of the utilities have satisfied NCSEA's request for such a statement. The Commission finds that even though DEC/DEP have expressed no opposition to NCSEA's third request that utilities not require the customer to prove, as a condition of eligibility, that the customer could leave the system or reduce its usage of the system through lower cost renewable energy or through an energy efficiency alternative and DNCP did not respond to NCSEA's request, such language is not necessary to insert in the guidelines and is more appropriately dealt with in reviewing a utility's specific JRT. The Commission finds that NCSEA's first request has been partially covered by the guidelines and any remaining portion of the request can be dealt with in a specific JRT filing.

The Commission agrees with DoD/FEA that the DoD/FEA is a valuable asset to North Carolina and a large employer within North Carolina. However, the Commission acknowledges that the DoD/FEA is distinguishable from other large employers as the DoD/FEA is a governmental entity. The Commission takes note of the 40,000 kW of potential demand response at Fort Bragg and encourages, as was suggested by DEC/DEP, the utilities to enter into discussions with the DoD/FEA to determine whether or not it is possible that a DoD/FEA-specific JRT or other tariff may be created to benefit all ratepayers.

The Commission has addressed NC WARN's relevant comments in its discussions and conclusions above.

<u>Cost Recovery</u>

The Commission agrees with the majority of the parties that if the Commission approves a specific JRT, cost recovery from the remaining customers is appropriate as long as the participating customers' discounted rates exceed the marginal cost of service and make some contribution to the utility's fixed costs. The regulatory compact supports the Commission's ratemaking decision. As a part of the regulatory compact, regulated utilities are entitled to a reasonable rate of return on investment and to recover prudently-incurred costs. Federal Power Comm'n v. Hope Nat'l Gas Co., 320 U.S. 591, 603 (1944); Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia, 262 U.S. 679 (1923). The Commission finds that any discounted rate that is established through an approved JRT must be in the public interest and must provide benefits to all rate classes as well as to the entire region. As CUCA and CIGFUR explained, if a large customer that would otherwise leave the system stays on the utility's system and pays its variable costs plus some contribution of the utility's fixed costs, all customers benefit in terms of paying reduced rates. All customers in the region further benefit by maintaining such large customer's revenue stream and corresponding multiplier impacts during periods of economic uncertainty. The State of North Carolina, as well as the nation, remains in a period of economic uncertainty, and to the extent that a JRT is properly designed and administered, it will benefit all of North Carolina's ratepayers. Approval of the guidelines in this order is the first step. The utilities, however, have indicated that they may decide to fund all or a portion of a JRT. Therefore, if the utility chooses to fund any portion of the JRT, the Commission does not object to a hybrid option proposing self-funding or partial funding by a utility.

The Commission finds and concludes that a utility may request approval of a JRT outside of a general rate case. The Commission further concludes that a determination regarding recovery of costs is most appropriately decided at the time the Commission is determining whether or not to approve a specific JRT.

Measurement and Verification

All parties agree that the benchmarks should be tied to a customer's employment levels. CIGFUR, CUCA and DEC/DEP state that some flexibility should be allowed in a JRT to allow a customer who has failed to maintain a minimum level of employment to not automatically be removed from the tariff. These parties suggest the customer should be allowed to explain the reasons why it has not been able to maintain the jobs and, if sufficient reasons exist, be allowed to remain on the JRT. Although, the Commission finds this determination is more appropriate once a specific JRT is filed, the Commission urges the utilities to create clear standards.

Furthermore, all of the utilities express concern regarding engaging in decision-making on whether or not a customer has complied with the tariff and whether or not the customer should remain on the tariff. The Commission agrees with the utilities that they should not be in a decision-making role regarding whether a customer should remain on a JRT and encourages the utilities to create clear, bright-line rules regarding eligibility and termination of eligibility in designing JRTs. For example, a JRT might provide that if a customer does not maintain certain minimum employment levels, the customer should be automatically removed from the JRT. The Commission agrees with the Public Staff that a properly designed JRT should require a minimum level of jobs to be maintained to remain on the JRT.

As far as the utilities' reporting on the customers on a JRT, the Commission finds that an aggregation of all of the customers on a utility-specific JRT and their aggregated data regarding employment levels will not provide sufficient information to determine whether the JRT is beneficial to all customers. On the other hand, the Commission is concerned that more detailed or customer-specific information would include confidential/competitive business information. Any requirement that an applicant release such sensitive information to the Commission could significantly undermine the purpose of a JRT, by discouraging targeted customers from applying to take advantage of the tariff designed to retain jobs and related load. The Commission finds that a possible avenue to satisfy the need for measurement and verification and to encourage helpful participation in a JRT is to have the utility compile the information on a customer by customer for an annual inspection by the Public Staff at the utility's place of business. The Public Staff could be involved in the initial decision-making regarding which customers should be removed from the tariff, if there is any dispute, and could file a generic aggregated report with the Commission regarding the effectiveness of the JRT upon completion of its review.

Therefore, based upon the comments received herein, the Commission is of the opinion that it should adopt the attached guidelines and filing requirements for job retention tariffs. The Commission notes that the guidelines adopted in this order contain a waiver clause that allows an applicant for job retention rates to request a modification of any of the filing requirements for good cause shown. The guidelines are also flexible enough to accommodate requests for job and load retention rates on a case-by-case basis or generic basis.

The Commission concludes from the comments received in this proceeding that it should allow differing approaches for the use of job retention rates at least for the time being, in order to allow the flexibility necessary for each company's needs. The guidelines adopted herein will further that objective, and they will do so in a manner that benefits all customer classes.

IT IS, THEREFORE, SO ORDERED that the Guidelines and Filing Requirements for Job Retention Tariffs attached hereto as Appendix A are hereby adopted.

ISSUED BY ORDER OF THE COMMISSION.
This the _8th_ day of December, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

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GUIDELINES AND FILING REQUIREMENTS FOR JOB RETENTION TARIFFS

(a) INTRODUCTION - A Job Retention Tariff (JRT) is a tariffed discount temporary in both overall life and applicability to certain customers, intended to allow the utility to prevent the immediate or imminent loss of North Carolina jobs and potentially the customer's related load. An appropriately designed and applied JRT will allow the utility to retain North Carolina jobs and as a related by-product its load in a manner that is beneficial to the utility, its ratepayers, and the State as a whole. However, no JRT shall be approved by the Commission without a showing that it is not unduly discriminatory and is in the public interest.

A JRT shall be offered only to those customers for whom the discounted rate would help prevent the loss of jobs and potentially electric load. The total amount paid for capacity and energy by the customers with regard to the load at risk, after application of the JRT discount, shall cover at least the variable costs and some contribution to fixed costs for the customers receiving the discount, to ensure that customers not receiving the discount are not overly burdened and customers receiving the discount are not unfairly advantaged.

The Commission is charged with the responsibility and authority to promote adequate, reliable, and economical utility service, and to provide just and reasonable rates and charges for that service. Therefore, it is important that the utility provide documentation that there is a need for the tariff, and that the tariff will help avoid a loss of jobs. Additional requirements or information may be ordered by the Commission as it considers appropriate under the circumstances.

(b) GENERAL PROVISIONS REGARDING A JRT:

(1) No JRT shall be approved by the Commission without a showing that it is not unduly discriminatory and is in the public interest.

(2) The utility applying for approval of a JRT shall demonstrate that the tariff is designed to assist a customer or group of customers to maintain jobs and potentially load.

(3) Because a JRT is intended to be temporary, it shall only be in effect for a maximum of five years measured from the date the approved tariff becomes effective. However, a utility may reapply for a subsequent JRT pursuant to these guidelines.

(4) A customer approved for service under the JRT shall only be eligible for such service until the expiration date of the JRT as set pursuant to the provisions of subparagraph (b)(3) above.

(5) A customer shall not be permitted to be served under a JRT at the same time it is being served under an economic development tariff or a self-generation deferral rate.

(6) During the period a customer is being served under a JRT, if the customer reduces the number of jobs or the amount of demand or energy targeted below the minimum level agreed to pursuant to the JRT contract between the utility and the customer, the customer's service under the tariff shall be cancelled.

(7) The appropriate ratemaking treatment of the impacts of a JRT will be determined as required in general rate case proceedings or if a JRT is approved outside of a rate case, the decision to defer costs to a general rate case will be determined during that proceeding.

(8) If a utility desires to offer a JRT to its customers on a pilot or full-scale basis and charge all discounts paid under the program to non-utility revenue and expenses, it may do so if approved by the Commission. However, a JRT offered in that manner shall be subject to no less a level of Commission oversight than one for which the costs of the discount are charged to utility operating revenues and expenses.

(9) The utility shall be required to compile a customer by customer analysis each year during the duration of the JRT of the impact of the JRT on targeted jobs, electric demand, and electric energy sales, and provide the Public Staff the opportunity to visit and review the information so that the Public Staff can evaluate both the effectiveness of the tariff and customer compliance with the terms of the tariff. The Public Staff shall file a report with the Commission indicating generally, without customer specific information, whether the JRT is effective, that customers were in compliance with their contracts, and whether the JRT remains in the public interest.

(10) Service under a JRT shall not be made available to any customer that does not have at least 12 months of operating experience with the utility.

(11) The process of determining customer eligibility to be served under an approved JRT shall include meaningful, verifiable qualifications to establish that a particular customer will achieve job retention and potentially retain customer load, and will use the discount to do so. JRT customer eligibility requirements shall also include a demonstration of financial viability on the part of the customer applying to receive the discount.

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(12) Prior to receiving service under the JRT, a customer shall be required to enter into a "JRT contract" with the utility. The contract shall include the level of jobs the customer shall agree to maintain, as well as any potential load that the customer and the utility agree should be maintained, and termination provisions for failing to maintain the minimum level of jobs, as well as any minimum load that the customer agrees to maintain. A contract requiring a "reasonable expectation" to maintain current employment levels is insufficient. The contract shall contain a provision affirming the customer's obligation to use the discount to achieve job retention. The contract shall also contain a provision affirming the customer's obligation to use the discount to achieve any potentially retained load that the customer has agreed to maintain although any agreed upon retained load is at the discretion of the customer.

(13) Prior to receiving service under a JRT, applying customers shall agree to receive an energy audit of their facility by the utility or its selected contractor within six months of service under the JRT. Customers who have undergone

an independent energy audit within the three years immediately prior to the commencement of service under the JRT may avoid this obligation by presenting documentation of the audit to the utility.

(c) PROVISIONS REGARDING THE DISCOUNT TO BE PROVIDED BY A JRT:

(1) The total amount paid for capacity and energy by the customers with regard to the load at risk, after application of the JRT discount, shall cover at least the customer’s variable costs and some portion of its fixed costs for the customers receiving the discount. Satisfaction of this requirement shall be demonstrated by an analysis of the impact of the JRT on the utility’s system, as follows:

(i) Marginal Cost Analysis. Any application for a JRT shall include a net present value analysis that demonstrates that the projected marginal revenues from continuing to serve the load at risk exceed the projected marginal costs for the target group, based on characteristics broadly representative of the group. This analysis shall be based on forecasted load and all projected marginal costs, including future costs of capital and expenses associated with projected increments or decrements of capacity and energy.

(ii) Rate Impact Analysis. The utility is required to identify the effect on the rates of other customers, both in terms of the impact on rates as a result of the discount and the impact on rates if load is lost without the discount. Expected benefits, identified in terms of rates, resource planning, load retention, and any other identifiable effects, shall be described in detail.

(d) PROVISIONS REGARDING DISCRIMINATION – G.S. 62-140(a) prohibits unreasonable differences as to rates between classes of service. As part of any application for a JRT, the utility shall file information demonstrating that the tariff is not unduly discriminatory and is in the public interest, and will comply with existing statutes and rules prohibiting unjust discrimination and undue preference. As part of that information, the Commission will consider the linkage between the proposed tariff and the benefits to all ratepayers related to the cost-effective avoidance of lost load, as well as the proposed customer eligibility requirements. In order to avoid undue discrimination, the utility must also apply its customer eligibility requirements, once approved, in a non-discriminatory manner.

(e) APPLICATION - All information provided as part or in support of any application for a JRT and in compliance with these guidelines shall be presumed public, absent an item-by-item request for confidential treatment. All items requested to be treated as confidential must be so identified. The utility application for approval of a JRT shall contain, either embodied in the application or attached thereto as exhibits, the following:

(1) The full and correct name, business address, and business telephone number of the applicant.

(2) Information regarding the customer group or groups that would be generally eligible to be considered for the discount, and justification for targeting the specific group or groups. The utility shall specifically identify all of the criteria it proposes to use to determine threshold eligibility for JRT consideration, including customer class or sub-class; minimum employment; minimum annual and/or monthly average and peak demands; and minimum annual kWh sales, taking into consideration recommendations from the comprehensive energy audit required under these guidelines.

(3) A copy of the currently applicable rate schedules and riders to which the utility desires to make the JRT applicable.

(4) The proposed JRT tariff.

(5) A copy of the proposed contract template.

(6) Support for the assertion that the proposed discount will comply with existing statutes and rules prohibiting unjust discrimination and undue preference.

(7) Quantification of the estimated maximum potential monetary exposure for other customers and how the applicant proposes to recover such costs.

(8) Information necessary to fully comply with the remainder of these guidelines.

(f) MODIFICATION OR WAIVER - In conjunction with any application for a JRT, the applicant may request a modification to or the waiver of any of the above filing requirements. The Commission may grant such request for good cause shown. For purposes of such a request, good cause shall include a demonstration that meeting a requirement without modification would:

(1) be impossible, impractical, or unduly burdensome to the applicant or customer; or

(2) not materially aid the Commission in determining whether the proposed rate is just and reasonable, is not unduly discriminatory, and is in the public interest.

DOCKET NO. E-100, SUB 111

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Consider	)	ORDER ADOPTING AMENDMENTS
Revisions to Commission Rule R8-60	)	TO COMMISSION RULE R8-60
on Integrated Resource Planning	)	

BY THE COMMISSION: General Statute 62-110.1(c) and G.S. 62-2(a)(3a) set forth certain policies and requirements for integrated resource planning (IRP) in North Carolina. The Commission implements G.S. 62-110.1(c) and G.S. 62-2(a)(3a) through the provisions of Commission Rule R8-60. By order issued on October 19, 2006, in Docket No. E-100, Subs 103, 110, and 111, the Commission opened a rulemaking proceeding "to consider revisions in the IRP process provided in Commission Rule R8-60."[1] On November 27, 2006, the Commission issued an order requesting comments and reply comments on proposed revisions to Rule R8-60. Based upon the consensus reached among the parties and the reasonableness of the parties' proposed revisions, on July 11, 2007, the Commission issued its Order Revising Integrated Resource Planning Rules that adopted the current Rule R8-60 covering the reporting requirements for both the biennial IRP reports and the annual update reports. In summary, the revised rule establishes different IRP reporting requirements for even-numbered years and odd-numbered years. Beginning in 2008, and every two years thereafter, the electric utilities are required to file a biennial report that includes comprehensive IRP information. Beginning in 2009, and every two years thereafter, the electric utilities are required to file an annual report that updates the information contained in their last biennial report. Pursuant to Rule R8-60(j), the procedure for intervention, comments, reply comments and hearing requests is the same for biennial and annual reports, except that initial comments are due within 150 days after the filing of biennial reports, but only 60 days after the filing of annual reports. Subsection (j) further requires that one or more public witness hearings shall be scheduled by the Commission.

In the Commission's 2013 IRP proceeding, in Docket No. E-100, Sub 137, several parties filed comments regarding the annual IRP reports and procedures.

In its April 11, 2014 comments, the Public Staff noted that despite the Commission's efforts to keep the IRP process within the established schedules the annual IRP process has typically taken more than a year to complete. In addition, the Public Staff stated that the utilities have indicated that in order for Commission directives to be fully considered in the utilities' next IRPs they need to receive the inputs from the Commission in late spring or early summer prior to the next IRP filing deadline. Further, the Public Staff opined that the complexity of issues and the sheer volume of information to be considered have resulted in a process that is sometimes disjointed and reactive, rather than constructive and deliberate. Therefore, the Public Staff believes that it may be appropriate to consider some changes to the IRP process to make it more robust and meaningful. Included among the changes considered by the Public Staff is a biennial process with less extensive information required, but with more stakeholder involvement in the development of the inputs and

[1] The October 19, 2006 order was prompted by recommendations made by a workgroup that was created by the Commission in connection with the 2005 IRP proceedings in Docket No. E-100, Sub 103.

scenarios to be used. In addition, comments and public hearings on the annual update reports could be required only at the discretion of the Commission.

The Public Staff recommended that the Commission request comments from the electric utilities and other parties on potential changes to the IRP process that may assist in making the process more robust and effective for all of the parties involved.

According to Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc. (collectively, Duke) in their joint reply comments filed on May 23, 2014, the IRP process has expanded in scope over time through incremental annual IRP rulings, along with a growing number of special interest group intervenors participating in the IRP process. Duke states that most of these intervenors focus only on issues of importance to their members or stakeholders. However, Duke notes that these intervenors lack the obligation to provide reliable power delivery and the obligation for least cost planning on behalf of all Duke’s customers that the IRP planning process requires. In addition, Duke maintains that many of the individual issues now being raised by intervenors in the IRP dockets have their own focused regulatory proceedings. For example, the IRP clearly has overlap with energy efficiency, REPS, fuel, CPCN, avoided cost and rate case proceedings. However, the IRP was never intended to supplant or supersede these more focused proceedings. Duke further contends that several of the recommendations expressed by intervenors in their IRP comments are the same recommendations made within the context of the more focused proceedings. Thus, this moves the IRP process away from its main focus of long-term planning toward more of a shorter term operational focus. In conclusion, Duke states that it would be supportive of working toward productive revisions to the annual update process.

Dominion North Carolina Power (DNCP), in its May 23, 2014 reply comments, states that it would welcome the opportunity to comment on the IRP process with an eye towards streamlining the annual updates to make them less burdensome. DNCP notes that its IRP process is ongoing and is designed to meet DNCP's biennial resource planning responsibilities in both Virginia and North Carolina. DNCP states that its IRP filing in Virginia is due on September 1 of each odd-numbered year. Thus, a streamlined update proceeding in North Carolina while DNCP is engaged in a full proceeding in Virginia would help DNCP maximize and conserve its planning resources.

Regarding stakeholder participation in the development of the utilities' IRPs, DNCP states that it does not believe a "North Carolina-wide" stakeholder process is necessary or would benefit each of the utilities in developing their IRPs. In addition, DNCP notes that its development of an IRP is a distinct process from Duke's planning process. However, DNCP does not oppose allowing up front input into its IRP process and has had a stakeholder review process in place in Virginia for several years. DNCP states that the Public Staff, Southern Environmental Law Center, Sierra Club and others routinely participate in its Virginia stakeholder review process and that this forum could be opened to other interested parties from North Carolina as well.

In its June 30, 2014 Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans (2013 IRP Order), the Commission noted these issues and stated that it would open a future docket to consider ideas for streamlining the annual update reporting process

On September 29, 2014, the Commission issued an Order Requesting Comments Regarding Rule R8-60 Amendments in this docket. The Order, among other things, requested comments on possible changes to the procedures used by the Commission in its review of the electric utilities' annual updates of their IRPs filed in odd-numbered years. In particular, the Order included four specific questions on which the Commission requested comments.

(1) Whether the Public Staff should be the only party expressly allowed to file comments and recommendations about the annual reports?

(2) Whether no public witness or evidentiary hearing should be scheduled unless the same is deemed necessary by the Commission and scheduled on the Commission's initiative?

(3) Whether there are categories of information or particular subjects that are not necessary for inclusion in the annual reports?

(4) Whether there are procedures or methods that should be adopted to achieve more stakeholder involvement in the annual reports prior to the reports being filed with the Commission?

Pursuant to the Order, initial comments were filed by Duke and DNCP (collectively, utilities); the Public Staff; North Carolina Sustainable Energy Association (NCSEA); and the Southern Alliance for Clean Energy, the Sierra Club, and South Carolina Coastal Conservation League (collectively, SELC intervenors). Reply comments were filed by the electric utilities.

In summary, the comments reflected a general consensus among the parties in their responses to the Commission’s first three questions regarding (1) parties who should be expressly allowed to comment on the utilities’ annual reports; (2) whether a finding of necessity should be required before a public witness and/or expert witness hearing is scheduled; and (3) the categories of information that are not necessary for inclusion in the update reports. On the other hand, there appeared to be a fundamental difference between the views of NCSEA and the SELC intervenors’ and those of the utilities regarding the parameters of a stakeholder process involving all parties in the formulation of the IRPs.

At the conclusion of the Public Staff's comments, the Public Staff recommended that the Commission establish an IRP working group to develop (1) a proposal for specific revisions to Rule R8-60 in regard to the content of the IRP updates, and (2) a plan for the creation of an integrated resource planning stakeholder process for DEC and DEP, and (3) any proposed changes to the existing DNCP integrated resource planning stakeholder process. Further, the Public Staff recommended that the working group be required to file a report with the Commission within 60 days of the issuance of the Commission's order establishing the group, with the report to include the recommendations of the majority of the parties, but also to include any differing positions. Finally, the Public Staff stated that it was willing to initiate and lead this IRP working group.

On January 30, 2015, the Commission issued an Order requesting that the Public Staff convene an IRP working group and that the working group file a report with the Commission within 60 days of the issuance of the Order.

On March 30, 2015, the Public Staff filed a motion requesting that the date for filing the working group's initial report be extended to May 29, 2015. On March 31, 2015, the Commission issued an Order granting the requested extension of time.

On May 29, 2015, the Public Staff filed a Report of the IRP Working Group (Report). The Public Staff states that the working group met on April 10, 2015, with representatives of the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR), the Carolina Utility Customers Association, Inc. (CUCA), DNCP, DEC, DEP, the North Carolina Electric Membership Corporation, the North Carolina Sustainable Energy Association (NCSEA), the North Carolina Waste Awareness and Reduction Network, the SELC intervenors, and the Public Staff.

The Public Staff states that the parties discussed (1) revisions to Rule R8-60 in regard to the content of the IRP updates, (2) the creation of an integrated resource planning stakeholder process for DEC and DEP, and (3) any proposed changes to the existing DNCP integrated resource planning stakeholder process. The parties were given an opportunity to provide their positions on each issue and any proposed changes to Rule R8-60. However, the parties were not able to reach consensus on each issue.

The following is a summary of the three main topics covered by the Report, including a summary of the positions of the parties.

REVISIONS TO RULE R8-60

Public Staff

The Public Staff proposed revisions to Commission Rule R8-60 with regard to the content of the IRP update reports. The Public Staff's proposed rule revisions were subsequently filed as Exhibit A to the Report. The purpose of the rule revisions is to clarify the filing requirements and reduce the work of the Commission and all parties in update years, while maintaining the ability of the Commission and other parties to monitor and review the utilities' IRP process, short-term action plans, and load forecasts. Under the Public Staff's proposal, in update years the utilities would file an updated forecast, a summary of significant amendments or revisions to its most recently filed biennial report, a short-term action plan, and a REPS compliance plan. In addition, the utilities would file data and tables for the planning horizon that (1) provide the information required by Rule R8-60(i)(1) regarding forecasts of load, supply-side resources, and demand-side resources; (2) provide the information required by Rule R8-60(i)(2) regarding generating facilities; (3) show existing, designated (including uprates), and non-traditional (DSM and renewables) resources and any resource gap; (4) show cumulative resource additions necessary to meet load obligation and reserve margins; and (5) show projections of load, capacity, and reserves for both the summer and winter periods. However, the data and tables would not be accompanied by the narrative explanation as contained in the biennial report.

The Public Staff states that this information should give the Public Staff sufficient information to allow it to monitor the utilities' forecasting, planning, and reserves in update years. Requiring the utilities to provide the data they generally provide in their IRPs but not the narrative description should allow the utilities to reduce their workload to some extent.[1] While the Public Staff would still review the update reports to ensure that they meet the requirements of the rule, the Public Staff and other parties would not file comments on the update reports. As a result, no reply comments would be filed by the utilities or intervenors. However, intervenors would have the right to request leave to file comments or to ask for a hearing should the information contained in the update reports merit further Commission attention. In addition, the Public Staff notes that the Commission always retains the right to request comments, further information, or to schedule an evidentiary hearing. Finally, the Commission would continue to allow the public to file statements of position on update reports, just as it does on biennial reports.

Within 60 days after the filing of the update reports or 60 days after September 1, whichever is later, the Public Staff would review the utilities' update reports and make a filing with the Commission indicating whether each utility had complied with the rule. The Public Staff's filing would not include substantive comments. However, substantive comments by the Public Staff on the REPS compliance plans would follow the same schedule allowed for REPS compliance plans filed with biennial IRP reports. While public witness hearings would continue to be held during update years, comments on the update reports would be received or hearings to receive expert testimony would be scheduled only at the Commission's discretion. Finally, each utility would be required to schedule a meeting with stakeholders to review its biennial or update report by November 1 of each year.

<u>CIGFUR</u>

CIGFUR supports the Public Staff's proposed revisions to Rule R8-60.

<u>CUCA</u>

CUCA has no objections to the rule changes proposed by the Public Staff. CUCA believes that the Public Staff's proposed rule changes will help to clarify the rule as it applies to the filing of the biennial IRPs and the update reports.

<u>Utilities</u>

Duke supports the Public Staff's recommended revisions to Rule R8-60 presented in Exhibit A to the Report. Consistent with Duke's initial comments, Duke concurs with the Public Staff's recommendations to streamline the update year process. The Public Staff's proposed update year filing requirements and procedure will reduce the IRP workload during the update year for all parties, while continuing to provide the Public Staff, other interested parties and the Commission sufficient information to monitor the utilities' forecasting, planning, and reserves during update years.

DNCP also supports the proposed revisions to Rule R8-60 presented in Exhibit A of the Report. Accordingly, DNCP withdraws its recommended rule changes set forth in Attachment A of its December 8, 2014 initial comments in this proceeding. DNCP believes that the Public Staff's recommended revisions to Rule R8-60 will achieve the Commission's original intent in initiating

[1] The Public Staff understands that DNCP will continue to submit a full IRP as it is required to do so annually in Virginia. DNCP would be allowed to continue this practice under the Public Staff's proposed rule change.

this proceeding of "streamlin[ing] the annual update reporting process so that it does not simply become another biennial proceeding with a different name." Order Requesting Comments Regarding Rule R8-60 Amendments, at 3. Further, DNCP opines that the proposed revisions maintain flexibility between the utilities' annual update filings, so that DNCP can continue to file a system-wide IRP in the North Carolina update year. Notably, legislation recently enacted in Virginia now requires DNCP to file its IRP in Virginia annually and modifies the timing of the Virginia IRP filing to July 1, 2015, and May 1 annually beginning in 2016. The Public Staff's proposed rule revisions allow DNCP the flexibility to file its IRP contemporaneously in both jurisdictions, while maintaining the existing timeline for Duke to file by September 1, as well as maintaining the current timeline allowed for Public Staff and other interested parties to review and comment on all the utilities' IRP filings. Finally, DNCP supports the proposed revisions extending the time allowed for reply comments during the biennial proceedings from 14 days to 60 days, which should eliminate the need for requests for extensions of time in the future.

NCSEA

NCSEA does not object to the Public Staff's proposed revisions to Rule R8-60.

SELC Intervenors

The SELC intervenors agree with the Public Staff's proposal regarding the content of the utility IRP updates. However, they do not agree with the proposal that intervenors not be allowed to file comments on the IRP updates unless granted leave by the Commission, or unless the Commission requests comments. The SELC intervenors submit that the Commission's procedures regarding IRP updates can be streamlined without foreclosing the opportunity for interested parties to comment on them. Moreover, the IRP updates may include important information that is relevant to major resource decisions, such as new unit certifications. Accordingly, the SELC intervenors believe that parties should be allowed to file comments on the IRP updates, and the utilities should be allowed to file reply comments. However, they would not oppose an expedited schedule for the filing of comments and reply comments.

CREATION OF AN INTEGRATED RESOURCE PLANNING STAKEHOLDER PROCESS FOR DEC AND DEP

Public Staff

As provided in section (m) of its proposed revision to Commission Rule R8-60, the Public Staff proposes that the utilities be required to schedule a meeting of interested IRP stakeholders by November 1 of each year. At this meeting, the utilities would review the contents of their biennial reports or update reports with the stakeholders, answer stakeholder questions, and consider stakeholder input. The Public Staff proposes that the utilities cover the following areas during these meetings: any changes to methodologies, assumptions that are major drivers of the plan, or substantial changes since the last biennial or update report; scenarios and portfolios; resulting plans, base plan, and selected plan; generation mix under various plans; short-term action plan and changes from prior year's short-term action plan; forecasts of renewables and DSM/EE; and assumptions regarding future regulations and their impacts.

In the IRP working group, the parties discussed the merits of having a third party facilitator versus having the utilities lead the meetings. Some parties believed that a third party facilitator would allow a more open exchange of information, but questions were raised as to who would pay for the facilitator. The Public Staff has participated in DNCP's IRP stakeholder process, which is led by DNCP, and has found it to be effective and informational. While DNCP led the discussion, parties were given an opportunity to ask questions and provide input. As the IRP is the plan of the utility and the utility personnel has the information about the plan, the Public Staff feels it is appropriate for the utility to have some control over this meeting. Thus, the Public Staff proposes that the utilities would convene and lead the meetings, as well as receive stakeholder questions and consider stakeholder input.

The Public Staff states that if the Commission adopts this proposal and requires DEC and DEP to convene IRP stakeholder meetings and DNCP to continue its current IRP stakeholder process, then it would be appropriate for the Commission to review the effectiveness of the IRP stakeholder process after a couple of years. The Public Staff recommends that the Commission seek comments on the effectiveness of these stakeholder meetings in intervenors' comments and the utilities' reply comments on the 2016 biennial IRP reports. By that time, stakeholder meetings following the filing of the 2015 IRP update report and the 2016 biennial report should have occurred and parties should be able to comment on whether these meetings improve the IRP process.

<u>CIGFUR</u>

CIGFUR supports the Public Staff's proposal for stakeholder meetings.

<u>CUCA</u>

CUCA has no objection to the stakeholder process as outlined by the Public Staff. CUCA believes that it will be beneficial for CUCA and the other parties to see the IRP as created by the utilities before commenting.

<u>Duke</u>

Duke supports the Public Staff's recommended approach to annual stakeholder review meetings on DEC's and DEP's IRPs. As previously stated in Duke's comments, DEC and DEP are agreeable to convening an annual IRP review meeting similar to the meeting DNCP has held on its IRP in Virginia. During the IRP working group meetings, the Public Staff and other parties discussed the organization of the DNCP IRP stakeholder meeting as well as other topics in an effort to refine the stakeholder meeting proposed to be held by DEC and DEP. Duke agrees with the Public Staff's recommended topics to be covered during the stakeholder meetings. Duke believes these topics will provide stakeholders with a good overview of the key drivers, planning assumptions and resource planning outcomes presented in DEC's and DEP's IRPs.

In addition, Duke does not oppose the Public Staff's recommendation that interested parties may comment on the effectiveness of the stakeholder meeting process during the 2016 biennial IRP proceeding. As stated in Duke's comments, the annual stakeholder meeting should be a vehicle to inform interested stakeholders about the utilities' IRPs, to answer questions, and to receive stakeholder input that can be considered by the utilities in developing future IRPs. Ultimately, however, the IRP process remains the responsibility of the utilities that have the obligation to provide reliable power and implement least-cost resource planning for their North Carolina customers. Duke agrees with the Public Staff that the current DNCP stakeholder process provides a good model that allows stakeholder review and feedback on the current IRP, which can be considered by the utilities in future resource planning, but does not cede any future resource planning to the stakeholders.

Finally, Duke does not agree that a third party facilitator will benefit the stakeholder review process. As stated in Duke's reply comments, the SELC intervenors' proposal for an "independent referee" that would report to the Commission on the stakeholder process represents an unnecessary expense, presumably to be funded by the companies and their customers, and an administrative burden without any clear benefit. DEC and DEP are committed to providing the Public Staff and other stakeholders with a constructive and informative IRP review process. Duke believes that concerns with the process can more appropriately be raised directly with the Commission in future biennial review proceedings, rather than through a report by a third party.

<u>NCSEA</u>

In its comments, NCSEA recommended that the Commission create a defined procedure for front-end engagement using the North Carolina Transmission Planning Collaborative/Transmission Advisory Group (NCTPC/TAG) as a model. NCSEA stated that such front-end engagement in the development of the utilities' biennial IRPs could reduce, if not eliminate, the current intensity of the tail-end engagement.

NCSEA contends that the stakeholder process proposed by the Public Staff does not give NCSEA or other non-governmental parties a sufficient front-end opportunity to engage with the utilities as they develop biennial IRPs. Instead, the revisions proposed by the Public Staff would require the utilities to review the contents of their respective IRP filings with stakeholders, answer stakeholder questions, and consider stakeholder input. The revisions proposed by the Public Staff do not utilize front-end stakeholder input in the limited way that the NCTPC/TAG process accepts proposed modelling scenarios for study from stakeholders at the beginning of each year and then selects up to two scenarios for study that it deems meritorious. Instead, under the Public Staff's proposal the utilities need only listen to stakeholder input, and may choose in their sole discretion to ignore suggestions.

The Public Staff noted that in response to NCSEA's analogy with the NCTPC/TAG process the utilities pointed out that developing IRPs is a year-round endeavor for the utilities. However, the Public Staff states that the development of transmission plans also is a year-round endeavor. In sum, the Public Staff states that the year-round nature of a planning process should not be used as a basis for diminishing non-utility stakeholder participation in the process.

NCSEA recognizes that the utilities are statutorily required to develop IRPs and that the decision of which scenario will be the base case scenario in an IRP lies with the utilities. During the working group's discussions, there appeared to be consensus among the utilities and the Public Staff that the proposed process would not necessarily diminish stakeholders' opportunity for constructive participation. Given such assurances, NCSEA will not stand in the way of implementation of this process, but NCSEA does ask, at a minimum, that implementation of the stakeholder process be made subject to review in the future.

SELC Intervenors

The SELC intervenors do not agree with the Public Staff’s proposal for a single stakeholder meeting to be held after the DEC and DEP IRPs are filed. As discussed in their comments, the SELC intervenors believe that enhanced opportunity for up-front involvement by interested parties in the development of the biennial IRPs would help to make the overall IRP procedures more robust and constructive. A single, post-filing meeting would not achieve this objective. Further, the stakeholder engagement process regarding DEC's and DEP's IRPs should include the following key steps:

- The Commission would retain a third party facilitator;
- DEC and DEP would share methodology and model inputs with stakeholders and the facilitator prior to development of the IRPs, and stakeholders would have the opportunity to provide feedback to DEC and DEP;
- DEC and DEP would share draft scenarios and sensitivities with stakeholders and the facilitator, and stakeholders would have the opportunity to provide feedback to DEC and DEP; and
- DEC and DEP would provide an overview of the results of their capacity expansion and production cost modeling and address questions or comments from stakeholders. This step is similar to the post-filing meeting proposed by the Public Staff.

If the Commission elects to require a single, post-filing meeting, however, the SELC intervenors agree that the topics proposed by the Public Staff would be appropriate topics for the meeting.

CHANGES TO THE EXISTING DNCP INTEGRATED RESOURCE PLANNING STAKEHOLDER PROCESS

Public Staff

The Public Staff does not propose any changes to DNCP's current process. The Public Staff believes that DNCP generally covers the list of topics recommended for the DEC and DEP stakeholder meetings, and would request that DNCP continue to review these topics during its stakeholder meetings.

CIGFUR

CIGFUR supports the Public Staff's position.

CUCA

CUCA believes that the current DNCP process allows all stakeholders to have appropriate input. Therefore, CUCA agrees with the Public Staff that no changes are needed to the current DNCP process.

<u>DNCP</u>

DNCP concurs with the Public Staff's recommendation that its existing stakeholder review process (SRP) should continue in its current form. DNCP confirms that the topics proposed for DEC and DEP to cover in their stakeholder process are currently addressed in DNCP's SRP, and DNCP commits to continue to cover these topics during each annual SRP meeting. Finally, for the reasons stated by the Public Staff as well as the reasons set forth in DNCP's comments and reply comments, DNCP opposes the recommendation that a third party SRP facilitator be used. DNCP agrees with the Public Staff that its current utility-led SRP process appropriately accommodates interested parties by recognizing that the IRP is a utility-driven resource planning obligation, while ensuring reasonable opportunities for stakeholder questions and input during the process.

<u>NCSEA</u>

DNCP’s SRP in Virginia does not provide formal front-end stakeholder input as requested in NCSEA’s comments. However, there appears to be consensus among the utilities and the Public Staff that the proposed process would not necessarily diminish stakeholders’ opportunity for constructive participation. Given such assurances, NCSEA will not stand in the way of implementation of this process, but NCSEA does ask, at a minimum, that the DNCP stakeholder process be made subject to review in the future.

<u>SELC Intervenors</u>

The SELC Intervenors do not propose any changes to DNCP’s SRP.

Discussion

The Commission appreciates the work of the Public Staff in convening the IRP working group and filing the working group Report, as well as the participation in this effort by all the parties.

In the 2013 IRP Order, the Commission discussed the concerns expressed by the parties about the odd-year update IRP process and stated:

> The Commission understands the time and complexity concerns that the parties have with the current IRP planning process. Between the time extension requests and the increasing complexity of the issues raised during the proceedings, it makes for drawn out IRP timelines. The Commission agrees that some modifications might be warranted, especially to these odd-year annual update proceedings. For this reason, the Commission intends to open a future docket which will request comments and reply comments on the specific issues of what might be done to streamline the annual update reporting process so that it does not simply become another biennial proceeding with a different name.

2013 IRP Order, at 32.

The main purpose of the annual IRP proceeding is planning. G.S. 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity." In State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation, 105 N.C. App. 136, 141, 412 S.E.2d 166, 170 (1992), the Court of Appeals discussed the nature and scope of the Commission's IRP proceedings. The Court described the IRP process as being akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific projects at a later time. On the other hand, it is not an appropriate proceeding for the Commission to use in issuing "directives which fundamentally alter a given utility's operations." With regard to the Commission's authority to issue specific directives, the Court cited the availability of the Commission's certificate of public convenience and necessity (CPCN) proceedings and complaint proceedings. Id., at 144, 412 S.E.2d at 173.

The Commission has two main goals in designing and implementing the IRP process: (1) to create a meaningful and efficient planning process for the utilities, and (2) to include a fair opportunity for interested parties to participate. In that context, the primary IRP planning tools are a 15-year forecast of the state's electric needs and various analyses of how the utilities might best meet those needs at the lowest cost. When the Commission amended Rule R8-60 in 2007 to change to the odd-year IRP updates, the Commission's purpose was to implement the "keep current an analysis" requirement of G.S. 62-110.1(c), while also preserving the effectiveness of the annual process as a planning tool. The Commission continues to believe that the 15-year planning horizon is an appropriate time span for the utilities' planning purposes. Nonetheless, the Commission also recognizes that there usually are not substantial changes in the electric usage forecasts and the least-cost means of meeting customers' needs from one year to the next. Therefore, alternating the utilities' filing of full IRPs with updated IRPs is an appropriate means of meeting the first goal of creating a meaningful and efficient planning process.

With regard to the second goal, a fair opportunity for interested parties to participate, the odd-year updates present a particular challenge that requires the Commission to balance the need for meaningful participation by all parties with the objective of having a streamlined IRP procedure. Within the working group, the two main issues on party participation are whether Rule R8-60 should automatically allow the filing of comments and reply comments, and whether the stakeholder meetings should be scheduled such that stakeholders can provide input prior to the utilities finalizing and filing their IRPs.

With respect to comments and reply comments on the updated IRPs, the Commission concludes that the appropriate balance is struck by allowing parties to request leave of the Commission to file comments. As noted previously, a main premise for using odd-year updated IRPs is the lack of substantial changes in the electric usage forecasts and the least-cost means of meeting customers' needs from one year to the next. However, if there are significant changes in odd year forecasts or available resource options, then the Commission will welcome a motion explaining those changes and requesting to make comments on them. In addition, the Commission notes that pursuant to Commission Rule R8-60(j), an intervenor may file an IRP of its own with respect to any utility. If an intervenor chooses to propose an alternative IRP, the intervenor's IRP should conform to the information and analytic requirements of Rule R8-60(c) – (j). The Public Staff's proposed amendments would eliminate this option with regard to the update IRPs. However, the Commission concludes that this option should remain available in all IRP proceedings and, therefore, will include it in amended Rule R8-60(l).

With respect to the annual IRP stakeholder meetings, NCSEA and the SELC intervenors expressed the need for an advance or front-end opportunity to provide input that will shape the utilities' IRPs, rather than merely an after-the-fact meeting that will not change the utilities' IRPs. However, the Commission views the annual IRP stakeholder meetings proposed by the Public Staff as both a tail-end and front-end opportunity for stakeholders. For example, the November 2015 IRP stakeholder meetings will provide stakeholders an opportunity to critique the 2015 IRP updates, and provide a front-end opportunity for stakeholders to get in on the ground floor of the utilities' 2016 IRP filings. Indeed, if a stakeholder has a proposed analysis or modeling change it can submit its proposal to the utility at the 2015 stakeholder meeting and request that the utility include the proposed analysis or modeling in the utility's 2016 IRP. If the utility refuses this request, the stakeholder could file a motion with the Commission requesting an Order from the Commission.

With regard to review of the REPS compliance plans that accompany the update reports, the proposed rule would allow the Public Staff and other intervenors 150 days to file comments on the REPS compliance plans, the same time period allowed for comments on the biennial reports. However, the Commission is concerned that five months is too long and would unduly slow the review of the update reports and the issuance of the Commission's final order. Therefore, the Commission will change the proposed time period for comments on the REPS compliance plans from 150 days to 60 days, the same 60 day period allowed to the Public Staff and intervenors for filing alternative update reports.

Finally, for the purpose of clarity and certainty with regard to the scheduling of the annual stakeholder meetings the Commission will revise proposed section (m) of the amended rule to provide that on or before November 30 of each year the utilities will hold a stakeholder meeting.

After careful consideration, the Commission concludes that the process recommended by the Public Staff and concurred with by most of the working group participants is reasonable and strikes the appropriate balance between meaningful participation by all parties and streamlining the odd-year IRP update procedure.

Conclusion

Based on the foregoing and the record, the Commission finds good cause to approve the Public Staff's proposed amendments to Commission Rule R8-60, with the three modifications noted above. The amended portion of the Rule, in strike-through and underlined version, is attached to this Order as Attachment A, and in final version as Attachment B.

IT IS, THEREFORE, ORDERED as follows:

1. That Commission Rule R8-60 shall be, and is hereby, amended in part as set forth in Attachment B to this Order.

2. That the amendments to Commission Rule R8-60 shall be effective and applicable to the integrated resource plan filed by Dominion North Carolina Power on July 1, 2015, in Docket No. E-100, Sub 141, and to integrated resource plans filed on and after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the _20th_ day of July, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

ATTACHMENT A
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(h) Filings.

(1) By September 1, 2008, and every two years thereafter, each utility subject to this rule shall file with the Commission its then current integrated resource plan, together with all information required by subsection (i) of this rule. This biennial report shall cover the next succeeding two-year period.

(2) By September 1 of each year in which a biennial report is not required to be filed, an ~~annual~~ update report shall be filed with the Commission containing an updated 15-year forecast of the items described in subparagraph (c)(1), as well as a summary of any 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.

(3) Each biennial and ~~annual~~ update report filed shall 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~~ update reports.

(4) Each biennial and ~~annual~~ update report shall include the utility's REPS compliance plan pursuant to Rule R8-67(b).

(5) If a utility considers certain information in its biennial or ~~annual~~ update report to be proprietary, confidential, and within the scope of G.S. 132-1.2, the utility may designate the information as "confidential" and file it under seal.

(i) Contents of Biennial Report~~s~~. — Each utility shall include in each biennial report~~, revised as applicable in each annual report,~~ the following:

(1) Forecasts of Load, Supply-Side Resources, and Demand-Side Resources.— The forecasts filed by each utility as part of its biennial report shall 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. In ~~both~~ the biennial ~~and annual~~ report~~s~~, the forecasts filed by each utility shall include, at a minimum, the following:

(i) The most recent ten-year history and a forecast of customers by each customer class, the most recent ten-year history and a forecast of energy sales (~~k~~MWh) by each customer class, and the most recent ten-year history and a forecast of the utility's summer and winter peak load (MW);

(ii) 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, with and without projected supply- or demand-side resource additions. The tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on the forecasted annual energy and peak loads on an annual basis for a 15-year period, and these effects also may be reported as an equivalent generation capacity impact; and

(iii) Where future supply-side resources are required, a description of the type of capacity/resource (MW rating, fuel source, base, intermediate, or peaking) that the utility proposes to use to address the forecasted need.

(2) Generating Facilities. — Each utility shall provide the following data for its existing and planned electric generating facilities (including planned additions and retirements, but excluding cogeneration and small power production):

(i) Existing Generation. — The utility shall provide a list of existing units in service, with the information specified below for each listed unit. The information shall be provided for a 15-year period beginning with the year of filing:

a. Type of fuel(s) used;
b. Type of unit (e.g., base, intermediate, or peaking);
c. Location of each existing unit;
d. A list of units to be retired from service with location, capacity and expected date of retirement from the system;
e. A list of units for which there are specific plans for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed; and
f. Other changes to existing generating units that are expected to increase or decrease generation capability of the unit in question by an amount that is plus or minus 10%, or 10 MW, whichever is greater.

(ii) Planned Generation Additions. — Each utility shall provide a list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition:

a. Type of fuel(s) used;
b. Type of unit (e.g. MW rating, baseload, intermediate, peaking);
c. Location of each planned unit to the extent such location has been determined; and

d. Summaries of the analyses supporting any new generation additions included in its 15-year forecast, including its designation as base, intermediate, or peaking capacity.

(iii) Non-Utility Generation. — Each utility shall provide a separate and updated list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and capacity (including its designation as base, intermediate, or peaking capacity). The utility shall also indicate which facilities are included in its total supply of resources. If any of

this information is readily accessible in documents already filed with the Commission, the utility may incorporate by reference the document or documents in its report, so long as the utility provides the docket number and the date of filing.

(3) Reserve Margins. — The utility shall provide a calculation and analysis of its winter and summer peak reserve margins over the projected 15-year period. To the extent the margins produced in a given year differ from target reserve margins by plus or minus 3%, the utility shall explain the reasons for the difference.

(4) Wholesale Contracts for the Purchase and Sale of Power.

(i) The utility shall provide a list of firm wholesale purchased power contracts reflected in the biennial report, including the primary fuel type, capacity (including its designation as base, intermediate, or peaking capacity), location, expiration date, and volume of purchases actually made since the last biennial report for each contract.

(ii) The utility shall discuss the results of any Request for Proposals (RFP) for purchased power it has issued since its last biennial report. This discussion shall include a description of each RFP, the number of entities responding to the RFP, the number of proposals received, the terms of the proposals, and an explanation of why the proposals were accepted or rejected.

(iii) The utility shall include a list of the wholesale power sales contracts for the sale of capacity or firm energy for which the utility has committed to sell power during the planning horizon, the identity of each wholesale entity to which the utility has committed itself to sell power during the planning horizon, the number of megawatts (MW) on an annual basis for each contract, the length of each contract, and the type of each contract (e.g., native load priority, firm, etc.).

(5) Transmission Facilities. — Each utility shall 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, including the capacity and voltage levels, location, and schedules for completion and operation. The utility shall also include a discussion of the adequacy of its transmission system (161 kV and above).

(6) Demand-Side Management. — Each utility shall 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. The utility also shall provide general information on any changes to the methods and assumptions used in the assessment since its last biennial report.

(i) For demand-side programs available at the time of the report, the utility shall provide the following information for each resource: the type of resource (demand response or energy efficiency); the capacity and energy available in the program; number of customers

enrolled in each program; the number of times the utility has called upon the resource; and, where applicable, the capacity reduction realized each time since the previous biennial report. The utility shall also list any demand-side resource it has discontinued since its previous biennial report and the reasons for that discontinuance.

(ii) For demand-side management programs it proposes to implement within the biennium for which the report is filed, the utility shall provide the following information for each resource: the type of resource (demand response and energy efficiency); a description of the new program and the target customer segment; the capacity and energy expected to be available from the program; projected customer acceptance; the date the program will be launched; and the rationale as to why the program was selected.

(iii) For programs evaluated but rejected the utility shall provide the following information for each resource considered: the type of resource (demand response or energy efficiency); a description of the program and the target customer segment; the capacity and energy available from the program; projected customer acceptance; and reasons for the program's rejection.

(iv) For consumer education programs the utility shall provide a comprehensive list of all such programs the utility currently provides to its customers, or proposes to implement within the biennium for which the report is filed, including a description of the program, the target customer segment, and the utility's promotion of the education program. The utility shall also provide a list of any educational program it has discontinued since its last biennial report and the reasons for discontinuance.

(7) Assessment of Alternative Supply-Side Energy Resources. — The utility shall include its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or ~~annual~~ update report.

(i) For the currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility shall provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility shall also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.

(ii) For alternative supply-side energy resources evaluated but rejected, the utility shall provide the following information for each resource considered: a description of the resource; the potential

capacity and energy associated with the resource; and the reasons for the rejection of the resource.

(8) Evaluation of Resource Options. — Each utility shall provide a description and a summary of the results of its analyses of potential resource options and combinations of resource options performed by it pursuant to subsection (g) of this rule to determine its integrated resource plan.

(9) Levelized Busbar Costs. — Each utility shall provide information on levelized busbar costs for various generation technologies.

(10) Smart Grid Impacts. – Each utility shall provide information regarding the impacts of its smart grid deployment plan on the overall IRP.

For purposes of this requirement, the term "smart" in smart grid shall be understood to mean, but is not limited to, a system having the ability to receive, process, and send information and/or data – essentially establishing a two-way communication protocol.

For purposes of this requirement, smart grid technologies that are implemented in a smart grid deployment plan may include those that: (1) utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility's distribution or transmission system; (2) optimize grid operations dynamically; (3) improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency; (4) provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; and/or (5) provide customers with usage information.

The information provided shall include:

(a) A description of the technology installed and for which installation is scheduled to begin in the next five years and the resulting and projected net impacts from installation of that technology, including, if applicable, the potential demand (MW) and energy (MWh) savings resulting from the described technology.

(b) A comparison to "gross" MW and MWh without installation of the described smart grid technology.

(c) A description of MW and MWh impacts on a system, North Carolina retail jurisdictional, and North Carolina retail customer class basis, including proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.

(j) Contents of Update Report~~s~~. — In addition to the information required by sections (h)(2)-(4) of this rule, each utility shall include in its update report~~,~~ data and tables that provide the following data for the planning horizon: (1) the information required by sections (i)(1) and (2) of this rule, including the utility's load forecast adjusted for the impacts of any new energy efficiency programs,

existing generating capacity with planned additions, uprates, derates, and retirements, planned purchase contracts, undesignated future resources identified by type of generation and MW rating, renewable capacity, demand-side management capacity, and any resource gap; (2) cumulative resource additions necessary to meet load obligation and reserve margins; and (3) projections of load, capacity, and reserves for both the summer and winter periods. A total system IRP may be filed in lieu of an update report for purposes of compliance with this section

~~(j)~~(k) Review of Biennial Reports.- Within 150 days after the later of either September 1 or the filing of each utility's biennial report ~~and within 60 days after the filing of each utility's annual report of amendments or revisions~~, the Public Staff or any other intervenor may file an integrated resource plan or report of its own as to any utility or may file an evaluation of or comments on the reports filed by the utilities, or both. The Public Staff or any intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. Within 60 ~~14~~ days after the filing of initial comments, the parties may file reply comments addressing any substantive or procedural issue raised by any other party. A hearing to address issues raised by the Public Staff or other intervenors may be scheduled at the discretion of the Commission. The scope of any such hearing shall be limited to such issues as identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

(l) Review of Update Reports. - Within 60 days after the filing of each utility's update report required by section (j) of this rule, the Public Staff or any other intervenor may file an update report of its own as to any utility. Further, within the same time period the Public Staff shall report to the Commission whether each utility's update report meets the requirements of this rule. Intervenors may request leave from the Commission to file comments. Comments will be received or expert witness hearings held on the update reports only if the Commission deems it necessary. The scope of any comments or expert witness hearing shall be limited to issues identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

(m) By November 30 of each year, each utility individually or jointly shall hold a meeting to review its biennial or update report with interested parties.

ATTACHMENT B
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(h) Filings.

(1) By September 1, 2008, and every two years thereafter, each utility subject to this rule shall file with the Commission its then current integrated resource plan, together with all information required by subsection (i) of this rule. This biennial report shall cover the next succeeding two-year period.

(2) By September 1 of each year in which a biennial report is not required to be filed, an update report shall be filed with the Commission containing an updated 15-year forecast of the items described in subparagraph (c)(1), as well as a summary of any 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.

(3) Each biennial and update report filed shall 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 update reports.

(4) Each biennial and update report shall include the utility's REPS compliance plan pursuant to Rule R8-67(b).

(5) If a utility considers certain information in its biennial or update report to be proprietary, confidential, and within the scope of G.S. 132-1.2, the utility may designate the information as "confidential" and file it under seal.

(i) Contents of Biennial Reports. — Each utility shall include in each biennial report the following:

(1) Forecasts of Load, Supply-Side Resources, and Demand-Side Resources. The forecasts filed by each utility as part of its biennial report shall 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. In the biennial reports the forecasts filed by each utility shall include, at a minimum, the following:

(i) The most recent ten-year history and a forecast of customers by each customer class, the most recent ten-year history and a forecast of energy sales (MWh) by each customer class, and the most recent ten-year history and a forecast of the utility's summer and winter peak load (MW);

(ii) 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, with and without projected supply or demand-side resource additions. The tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on the forecasted annual energy and peak loads on an annual basis for a 15-year period, and these effects also may be reported as an equivalent generation capacity impact; and

(iii) Where future supply-side resources are required, a description of the type of capacity/resource (MW rating, fuel source, base, intermediate, or peaking) that the utility proposes to use to address the forecasted need.

(2) Generating Facilities. — Each utility shall provide the following data for its existing and planned electric generating facilities (including planned additions and retirements, but excluding cogeneration and small power production):

(i) Existing Generation. — The utility shall provide a list of existing units in service, with the information specified below for each listed unit. The information shall be provided for a 15-year period beginning with the year of filing:

a. Type of fuel(s) used;

b. Type of unit (e.g., base, intermediate, or peaking);

c. Location of each existing unit;

d. A list of units to be retired from service with location, capacity and expected date of retirement from the system;

e. A list of units for which there are specific plans for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed; and

f. Other changes to existing generating units that are expected to increase or decrease generation capability of the unit in question by an amount that is plus or minus 10%, or 10 MW, whichever is greater.

(ii) Planned Generation Additions. — Each utility shall provide a list of planned generation additions, the rationale as to why each listed generation addition was selected, and a 15-year projection of the following for each listed addition:

a. Type of fuel(s) used;

b. Type of unit (e.g. MW rating, baseload, intermediate, peaking);

c. Location of each planned unit to the extent such location has been determined; and

d. Summaries of the analyses supporting any new generation additions included in its 15-year forecast, including its designation as base, intermediate, or peaking capacity.

(iii) Non-Utility Generation. — Each utility shall provide a separate and updated list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and capacity (including its designation as base, intermediate, or peaking capacity). The utility shall also indicate which facilities are included in its total supply of resources. If any of

this information is readily accessible in documents already filed with the Commission, the utility may incorporate by reference the document or documents in its report, so long as the utility provides the docket number and the date of filing.

(3) Reserve Margins. — The utility shall provide a calculation and analysis of its winter and summer peak reserve margins over the projected 15-year period. To the extent the margins produced in a given year differ from target reserve margins by plus or minus 3%, the utility shall explain the reasons for the difference.

(4) Wholesale Contracts for the Purchase and Sale of Power.

(i) The utility shall provide a list of firm wholesale purchased power contracts reflected in the biennial report, including the primary fuel type, capacity (including its designation as base, intermediate, or peaking capacity), location, expiration date, and volume of purchases actually made since the last biennial report for each contract.

(ii) The utility shall discuss the results of any Request for Proposals (RFP) for purchased power it has issued since its last biennial report. This discussion shall include a description of each RFP, the number of entities responding to the RFP, the number of proposals received, the terms of the proposals, and an explanation of why the proposals were accepted or rejected.

(iii) The utility shall include a list of the wholesale power sales contracts for the sale of capacity or firm energy for which the utility has committed to sell power during the planning horizon, the identity of each wholesale entity to which the utility has committed itself to sell power during the planning horizon, the number of megawatts (MW) on an annual basis for each contract, the length of each contract, and the type of each contract (e.g., native load priority, firm, etc.).

(5) Transmission Facilities. — Each utility shall 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, including the capacity and voltage levels, location, and schedules for completion and operation. The utility shall also include a discussion of the adequacy of its transmission system (161 kV and above).

(6) Demand-Side Management. — Each utility shall 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. The utility also shall provide general information on any changes to the methods and assumptions used in the assessment since its last biennial report.

(i) For demand-side programs available at the time of the report, the utility shall provide the following information for each resource: the type of resource (demand response or energy efficiency); the capacity and energy available in the program; number of customers

enrolled in each program; the number of times the utility has called upon the resource; and, where applicable, the capacity reduction realized each time since the previous biennial report. The utility shall also list any demand-side resource it has discontinued since its previous biennial report and the reasons for that discontinuance.

(ii) For demand-side management programs it proposes to implement within the biennium for which the report is filed, the utility shall provide the following information for each resource: the type of resource (demand response and energy efficiency); a description of the new program and the target customer segment; the capacity and energy expected to be available from the program; projected customer acceptance; the date the program will be launched; and the rationale as to why the program was selected.

(iii) For programs evaluated but rejected the utility shall provide the following information for each resource considered: the type of resource (demand response or energy efficiency); a description of the program and the target customer segment; the capacity and energy available from the program; projected customer acceptance; and reasons for the program's rejection.

(iv) For consumer education programs the utility shall provide a comprehensive list of all such programs the utility currently provides to its customers, or proposes to implement within the biennium for which the report is filed, including a description of the program, the target customer segment, and the utility's promotion of the education program. The utility shall also provide a list of any educational program it has discontinued since its last biennial report and the reasons for discontinuance.

(7) Assessment of Alternative Supply-Side Energy Resources. — The utility shall include its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility shall also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or update report.

(i) For the currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility shall provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility shall also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance.

(ii) For alternative supply-side energy resources evaluated but rejected, the utility shall provide the following information for each resource considered: a description of the resource; the potential

capacity and energy associated with the resource; and the reasons for the rejection of the resource.

(8) Evaluation of Resource Options. — Each utility shall provide a description and a summary of the results of its analyses of potential resource options and combinations of resource options performed by it pursuant to subsection (g) of this rule to determine its integrated resource plan.

(9) Levelized Busbar Costs. — Each utility shall provide information on levelized busbar costs for various generation technologies.

(10) Smart Grid Impacts. – Each utility shall provide information regarding the impacts of its smart grid deployment plan on the overall IRP.

For purposes of this requirement, the term "smart" in smart grid shall be understood to mean, but is not limited to, a system having the ability to receive, process, and send information and/or data – essentially establishing a two-way communication protocol.

For purposes of this requirement, smart grid technologies that are implemented in a smart grid deployment plan may include those that: (1) utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility's distribution or transmission system; (2) optimize grid operations dynamically; (3) improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency; (4) provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; and/or (5) provide customers with usage information.

The information provided shall include:

(a) A description of the technology installed and for which installation is scheduled to begin in the next five years and the resulting and projected net impacts from installation of that technology, including, if applicable, the potential demand (MW) and energy (MWh) savings resulting from the described technology.

(b) A comparison to "gross" MW and MWh without installation of the described smart grid technology.

(c) A description of MW and MWh impacts on a system, North Carolina retail jurisdictional, and North Carolina retail customer class basis, including proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.

(j) Contents of Update Reports. — In addition to the information required by sections (h)(2)-(4) of this rule, each utility shall include in its update report data and tables that provide the following data for the planning horizon: (1) the information required by sections (i)(1) and (2) of this rule, including the utility's load forecast adjusted for the impacts of any new energy efficiency programs, existing generating capacity with planned additions, uprates, derates, and retirements, planned purchase contracts, undesignated future resources identified by type of generation and MW rating, renewable capacity, demand-side management capacity, and any resource gap;

(2) cumulative resource additions necessary to meet load obligation and reserve margins; and (3) projections of load, capacity, and reserves for both_the summer and winter periods. A total system IRP may be filed in lieu of an update report for purposes of compliance with this section.

(k) Review of Biennial Reports. — Within 150 days after the later of either September 1 or the filing of each utility's biennial report, the Public Staff or any other intervenor may file an integrated resource plan or report of its own as to any utility or may file an evaluation of or comments on the reports filed by the utilities, or both. The Public Staff or any intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. Within 60 days after the filing of initial comments, the parties may file reply comments addressing any substantive or procedural issue raised by any other party. A hearing to address issues raised by the Public Staff or other intervenors may be scheduled at the discretion of the Commission. The scope of any such hearing shall be limited to such issues as identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

(l) Review of Update Reports. — Within 60 days after the filing of each utility's update report required by section (j) of this rule, the Public Staff or any other intervenor may file an update report of its own as to any utility. Further, within the same time period the Public Staff shall report to the Commission whether each utility’s update report meets the requirements of this rule. Intervenors may request leave from the Commission to file comments. Comments will be received or expert witness hearings held on the update reports only if the Commission deems it necessary. The scope of any comments or expert witness hearing shall be limited to issues identified by the Commission. One or more hearings to receive testimony from the public, as required by law, shall be set at a time and place designated by the Commission.

(m) By November 30 of each year, each utility individually or jointly shall hold a meeting to review its biennial or update report with interested parties.

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Implement Session Law 2007-397	))))	ORDER MODIFYING THE SWINE AND POULTRY WASTE SET-ASIDE REQUIREMENTS AND PROVIDING OTHER RELIEF

BY THE COMMISSION: On August 12, 2015, a joint motion to modify and delay the 2015 requirements of G.S. 62-133.8(e) and (f) was filed by Duke Energy Carolinas, LLC (DEC);[1] Duke Energy Progress, LLC (DEP);[2] Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (Dominion);[3] GreenCo Solutions, Inc.; Public Works Commission of the City of Fayetteville; EnergyUnited Electric Membership Corporation; Halifax Electric Membership Corporation; the Tennessee Valley Authority (TVA);[4] North Carolina Eastern Municipal Power Agency (NCEMPA);[5] and North Carolina Municipal Power Agency Number 1 (NCMPA1)[6] (hereinafter referred to collectively as the Joint Movants). The Joint Movants requested that the Commission relieve them of compliance with G.S. 62-133.8(e) (Compliance With [North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS)] Requirement Through Use of Swine Waste Resources) and G.S. 62-133.8(f) (Compliance With REPS Requirement Through Use of Poultry Waste Resources) by delaying their need to comply with these requirements by one year until 2016. The joint motion further requested that the Commission allow the Joint Movants to bank any poultry and swine renewable energy certificates (RECs) previously or subsequently acquired for use in future compliance years and allow the Joint Movants to replace compliance with the swine and poultry waste set-aside requirements in 2015 with other compliance measures pursuant to G.S. 62-133.8(b), (c), and (d). The Joint Movants stated that they have individually and collectively made reasonable efforts to comply with the REPS poultry and swine waste resource provisions and that the relief sought is in the public

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[1] DEC asserted that it is also acting in its capacity as REPS compliance aggregator for Blue Ridge Electric Membership Corporation (EMC), Rutherford EMC, the City of Dallas, Forest City, City of Concord, the Town of Highlands and the City of Kings Mountain.

[2] DEP asserted that it is also acting in its capacity as REPS compliance aggregator for the Towns of Sharpsburg, Lucama, Black Creek, and Stantonsburg, and the City of Waynesville.

[3] Dominion asserted that it is also acting in its capacity as REPS compliance aggregator for the Town of Windsor.

[4] TVA asserted that it is acting in its capacity as REPS compliance aggregator for Blue Ridge Mountain EMC, Mountain Electric Cooperative, Tri-State EMC and Murphy Electric Power Board.

[5] NCEMPA asserted that it is acting in its capacity as REPS compliance aggregator for its 32 member municipalities which are electric power suppliers.

[6] NCMPA1 asserted that it is acting in its capacity as REPS compliance aggregator for its 19 member municipalities which are electric power suppliers.

interest. The Joint Movants requested that the Commission consider and approve their joint motion without an evidentiary hearing.

On August 18, 2015, the Commission issued an Order Requesting Comments. The Order requested comments from interested parties on the Joint Movants' motion to be filed by October 2, 2015. In their comments, parties were requested to address whether the poultry waste set-aside requirement would be achievable in 2015 if it were maintained at the 2014 level. On October 2, 2015, the Commission granted a motion for an extension of time filed by the North Carolina Pork Council (NCPC), extending the deadline by which parties may file comments until October 9, 2015.

On October 2, 2015, the North Carolina Poultry Federation (NCPF), the Public Staff, and the North Carolina Sustainable Energy Association (NCSEA) filed comments on the Joint Movant's motion. On October 9, 2015 NCPC and Optima KV, LLC (Optima), filed comments on the Joint Movant's motion. On October 15, 2015, the Public Staff filed revised comments. On October 16, 2015, DEC and DEP filed supplemental comments.

On October 27, 2015, the Joint Movants filed reply comments. On November 9, 2015, NCPC filed a motion to strike the Joint Movants' reply comments. NCPC noted that the Commission's August 18, 2015 Order Requesting Comments did not request or authorize reply comments. The Commission finds that the Joint Movant's reply comments are unnecessary to reaching its determination, and, therefore, grants NCPC's motion to strike.

NCPF, in its comments, stated that it "does not oppose the requested delay in meeting the 2015 statutory requirements" with regard to the poultry waste set-aside. NCPF further stated that it takes no position with regard to banking poultry waste RECs and substituting other types of RECs for 2015 compliance purposes.

The Public Staff, in its initial comments, stated that it had reviewed the Joint Movants' motion, the triannual reports, and the data in the North Carolina Renewable Energy Tracking System (NC-RETS). The Public Staff concluded that the Joint Movants are making good faith efforts to comply with the swine and poultry waste set-aside requirements, but will fall short for 2015. The Public Staff further stated in its initial comments that if the 2014 poultry waste level were maintained "there are currently insufficient in-state poultry waste RECs to meet the in-state portion of the 2014 poultry waste requirement in 2015." However, in its revised comments, the Public Staff added "other resources in accordance with Section 4 of S.L. 2010-195, as amended by S.L. 2011-279 (Senate Bill 886)" (S886 RECs) to its analysis of whether the poultry waste set-aside requirement could be achieved at the 2014 level. The addition of S886 RECs to the Public Staff's analysis resulted the following amended conclusion:

> Based on the Public Staff's analysis, if the Commission were to use its authority under G.S. 62-133.8(i)(2) to maintain the poultry waste requirement at its current level of 170,000 MWh for an additional year, it appears that the Electric Suppliers could achieve compliance with the amended requirement in 2015.

The Public Staff recommended that the Commission delay the Joint Movants' need to comply with the swine waste set-aside requirement of G.S. 62-133.8(e) until calendar year 2016 and modify the requirements of G.S. 62-133.8(f) to maintain the poultry waste set-aside requirement at 170,000 MWh for calendar year 2015.

NCSEA, in its comments, stated that "[w]here some equitable level of partial compliance is a viable option, yet another complete delay of the swine waste and poultry waste set-aside requirements would run counter to the intent of the General Assembly." NCSEA recommended that the Commission require the stakeholders to partake in a joint analysis to determine the adequate level of partial compliance.

Optima, in its comments, stated that DEC and DEP have not made reasonable efforts to comply with the swine waste set-aside requirement "because they have refused to contract with Optima for the purchase of swine waste biogas at a commercially reasonable price, even though Optima's technology is viable (as confirmed through independent expert review), and it has long-term feedstock agreements in place." Optima described its facilities and technology and stated that it had proposed to sell DEC and DEP "biogas to generate electricity would produce the equivalent of approximately 10,500 RECs per year." Optima further stated that DEC and DEP "rejected the proposal out of hand based on price and refused to meet with Optima to discuss the project." Optima stated that it attempted to contract with DEC and DEP at a lower price, but such negotiations were continually rejected. Optima stated that "the proposed price would allow DEP or DEC to meet a significant portion of its swine waste set-aside obligation while consuming a relatively small percentage of its REPS cost cap" and noted Commission precedent that the set-asides should have priority under the cost cap over the general requirement. Optima recommended that the Commission "find that DEP and DEC have not made reasonable efforts to comply with their swine waste set-aside obligations in 2015." Further, Optima recommended that the Joint Movants "should be required to partially comply with the 2015 swine waste set-aside requirements to the extent that they are able to do so based on RECs previously acquired." Optima concurred with NCSEA's approach to establish partial compliance. Optima also recommended changes to the triannual reporting requirements to include initial offer prices, reasons that contracts were not executed, and the current status of any contracts entered into, including any reason for termination. Finally, Optima recommended that the minutes from the Public Staff's stakeholder meetings be made publicly available.

NCPC, in its comments, expressed concerns that requests to delay the set-asides have "become the norm", that the motions for delay have become formulaic, and that the triannual reports have "become less than fully informative." NCPC stated that "by acknowledging that contracts were not entered due to price, the [Joint Movants] have now placed 'price' squarely in issue." Thus, NCPC contended that the Commission must determine that the Joint Movants' contentions regarding price are accurate and reasonable before it can determine that a reasonable compliance effort has been put forth. NCPC stated its support for the approach recommended by Optima using the legislative cost cap as a surrogate for reasonableness. NCPC stated that there is no shortage of swine waste in the State and that proven technologies exist such that production facilities would be built at an adequate price point. NCPC recommended that the triannual reports be reduced to semiannual and provided a new list of information to be included in the reports to avoid the formulaic nature of the reports. NCPC also stated its support for Optima's recommendation that each electric power supplier submit to the Commission a compliance plan for meeting the requirements of the set-aside and NCSEA's recommendation regarding partial compliance.

DEC and DEP, in their supplemental comments, stated that if the poultry waste set-aside requirement "were to be held at the state-wide 2014 level of 170,000 MWh, the Companies collectively would be able to meet the compliance target."

G.S. 62-133.8(i)(2) states that the Commission, in developing rules, shall:

> Include a procedure to modify or delay the provisions of subsections (b), (c), (d), (e), and (f) of this section in whole or in part if the Commission determines that it is in the public interest to do so. The procedure adopted pursuant to this subdivision shall include a requirement that the electric power supplier demonstrate that it made a reasonable effort to meet the requirements set out in this section.

Commission Rule R8-67(c)(5) states:

> In any year, an electric power supplier or other interested party may petition the Commission to modify or delay the provisions of G.S. 62-133.8(b), (c), (d), (e) and (f), in whole or in part. The Commission may grant such petition upon a finding that it is in the public interest to do so. If an electric power supplier is the petitioner, it shall demonstrate that it has made a reasonable effort to meet the requirements of such provisions.

The Commission has previously exercised this authority and delayed compliance with the swine and poultry waste set-aside requirements on two occasions: first in its November 29, 2012 Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief (2012 Delay Order), and a second time in its March 26, 2014 Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief (2013 Delay Order), both issued in Docket No. E-100, Sub 113. Additionally, the Commission delayed compliance with the swine waste set-aside requirement a third time in its November 13, 2014 Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief (2014 Delay Order).

Based on the triannual reports submitted by the electric power suppliers in Docket No. E-100, Sub 113A, the Joint Movants' motion, the parties' comments, and the entire record herein, the Commission finds that the State's electric power suppliers have made a reasonable effort to comply with the 2015 statewide swine waste set-aside requirements established by G.S. 62-133.8(e), but will not be able to comply. Compliance with the swine waste set-aside requirement has been hindered by the fact that the technology of power production from swine waste continues to be in its early stages of development. No party presented evidence that the aggregate 2015 swine waste set-aside requirement could be met. While Optima stated that DEC and DEP had not made a good faith effort to comply with the swine waste set-aside requirement, it acknowledged that "DEP and DEC are not now in a position to comply with the swine waste set-aside in 2015, whether or not they contract with Optima." Optima further added that "the initial Optima project can deliver some biogas relatively quickly, the project will take approximately nine (9) months to be fully operational. The other two Optima projects are not as far along in development and one of them is unlikely to be able to produce biogas in 2016." NCPC stated that projects could be developed in North Carolina at the right price point; however, NCPC made no contention that the swine waste set-aside requirement could be met in 2015.

The Commission, at this time, is not persuaded that pricing disputes were a significant contributing factor to the Joint Movants' failure to meet the swine waste set-aside requirement. Therefore, based on the overall availability of swine waste RECs, the lack of technological progress in the market, and contract performance, the Commission finds it appropriate to delay the swine waste set-aside by one year. However, the Commission also finds merit in NCPC's contention that it may be inappropriate for the electric power suppliers to reject proposals solely based on the price of RECs when there is ample room under the REPS cost-cap. The Commission has clearly stated that the set-aside requirements take priority and the General Assembly has established the reasonable limit an electric power supplier can spend for compliance with the REPS. Therefore, while the Commission does not intend to interject itself into negotiations, further monitoring of such negotiations may be necessary in future years. The failure to contract with swine waste developers is directly relevant to the question of whether the electric power suppliers have made a good faith effort to comply with the swine waste set-aside requirement. Therefore, the Commission finds merit in some of the NCPC and Optima's proposed changes to the triannual reporting requirements and stakeholder process.

The Commission finds good cause to amend the triannual reporting requirement to occur semiannually. In addition to the previously required information, the electric power suppliers shall include the following information in their semiannual reports: (1) an estimate of the number of RECs needed to comply with the swine waste set-aside in the present calendar year; (2) project developers with whom the electric supplier submitting the report had formal discussions with during the prior six months, a description of the discussions, including their current status, and any proposed project resulting from the discussion; and (3) whether any proposals were rejected during the reporting period and a thorough discussion of why an agreement could not be reached. The Commission also finds merit in the suggestion that the stakeholder meetings be synchronized with the filing of the semiannual reports and requests that the Public Staff convene a stakeholder meeting within 6 weeks of the date a semiannual report is filed. Finally, the Commission requests that the Public Staff file minutes from the stakeholder meetings in Docket No. E-100, Sub 113A. The Commission will not require the number of RECs currently held, the number expected by the end of the calendar year, the contracts in place and the RECs that will be supplied under the contract by the end of the year to be submitted at this time, as that information has typically been treated as confidential.

With regard to NCSEA, NCPC, and Optima's request that a level of partial compliance with the swine waste set-aside requirement be required in 2015 and that the Joint Movants not bank their previously acquired swine waste RECs for future use, the Commission notes that it has permitted the Joint Movants to bank RECs for three consecutive years and the cumulative effect of this banking has yet to result in the ability to comply with the initial swine waste set-aside requirement. To require that the Joint Movants retire their banked swine RECs would, thus, result in wiping the slate clean for compliance purposes in future years. Therefore, the Commission finds that it is in the public interest to delay the entire requirement of G.S. 62-133.8(e) for one year. Electric power suppliers that have acquired swine waste RECs for 2015 REPS compliance should be allowed to bank such RECs for swine waste set-aside requirement compliance in future years. Electric power suppliers should continue to make efforts to comply with the swine waste set-aside requirement as modified by this Order.

Based on the triannual reports submitted by the electric power suppliers in Docket No. E-100, Sub 113A, the Joint Movants' motion, the parties' comments, and the entire record herein, the Commission further finds that the State's electric power suppliers have made a reasonable effort to comply with the 2015 statewide poultry waste set-aside requirement established by G.S. 62-133.8(f), but will not be able to comply. Compliance with the poultry waste set-aside requirement has been hindered by the fact that the technology of power production from poultry waste continues to be in its early stages of development. No party presented evidence that the aggregate 2015 poultry waste set-aside requirement could be met; however, the Public Staff, DEC, and DEP stated that, due to the availability of S886 RECs, the 2014 level of the poultry waste set-aside could be maintained. Unlike the swine waste set-aside requirement, the market for poultry waste RECs, including S886 RECs, appears at least robust enough to sustain the 2014 requirement of 170,000 MWh going forward. Therefore, the Commission finds good cause to modify the poultry waste set-aside requirement established by G.S. 62-133.8(f) by adding an additional year (2015) of compliance at the 170,000 MWh threshold, prior to escalating the requirement to 700,000 MWh.

IT IS, THEREFORE, ORDERED as follows:

1. That the 2015 swine waste set-aside requirement of G.S. 62-133.8(e), as established in the Commission's 2014 Delay Order, is delayed for one additional year. The electric power suppliers, in the aggregate, shall comply with the requirements of G.S. 62-133.8(e) according to the following schedule:

Calendar Year	Requirement for Swine Waste Resources
2016-2017	0.07%
2018-2020	0.14%
2021 and thereafter	0.20%

Electric power suppliers shall be allowed to bank any swine waste RECs previously or subsequently acquired for use in future compliance years and to replace compliance with the swine waste set-aside requirement in 2015 with other compliance measures pursuant to G.S. 62-133.8(b), (c), and (d).

2. That the 2015 poultry waste set-aside requirement of G.S. 62-133.8(f), as established in the Commission's 2013 Delay Order, is modified to maintain the same level as the 2014 requirement, and that the scheduled increases in the requirement be delayed by one year. The electric power suppliers, in the aggregate, shall comply with the requirements of G.S. 62 133.8(f) according to the following schedule:

Calendar Year	Requirement for Poultry Waste Resources
2014	170,000 MWh
2015	170,000 MWh
2016	700,000 MWh
2017 and thereafter	900,000 MWh

3. That the triannual filing requirement first required by the Commission's 2012 Delay Order and that now, pursuant to the 2013 Delay Order, applies to DEP, DEC, Dominion, GreenCo, Fayetteville, EnergyUnited, Halifax, NCEMPA and NCMPA1 shall be due semiannually. The first

semiannual report shall be due to the Commission no later than January 1, 2016. Thereafter, the report shall be due to the Commission on each June 1 and December 1 until the Commission finds that it is no longer necessary. In addition to the information specified in Ordering Paragraph 4 of the Commission's 2012 Delay Order, the report shall include: (1) an estimate of the number of RECs needed to comply with the swine waste set-aside in the present calendar year; (2) project developers with whom the electric supplier submitting the report had formal discussions with during the prior six months, a description of the discussions, including their current status, and any proposed project resulting from the discussion; and (3) whether any proposals were rejected during the reporting period and a thorough discussion of why an agreement could not be reached.

4. That the Public Staff is requested to arrange and facilitate stakeholder meetings within six weeks of the filing of a semiannual report. The electric power suppliers subject to the semiannual filing requirement shall attend. Developers and other stakeholders are encouraged to participate and discuss potential obstacles to achieving the swine and poultry waste set-aside requirements and options for addressing them. The Public Staff is requested to file minutes from the stakeholder meetings in Docket No. E-100, Sub 113A.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of December, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-100, SUB 138

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Standardize the Indices Used to Measure and Report Electric Utility Service Quality	)))	ORDER ADOPTING NEW SERVICE QUALITY RULES FOR ELECTRIC UTILITIES

BY THE COMMISSION: On June 29, 2012, the Commission issued an Order Approving Merger Subject to Regulatory Conditions and Code of Conduct in Docket Nos. E-2, Sub 998 and E-7, Sub 986 (Merger Dockets). In Ordering Paragraph No. 22, the Commission directed that "Duke Energy Carolinas, LLC (DEC), Progress Energy Carolinas, Inc., (PEC)[1] [the Companies], and the Public Staff will work with other interested parties to propose within 90 days after the close of the merger[2] a Commission rulemaking to standardize the indices used to measure and report electric utility service quality."

On November 26, 2012, after being granted extensions of time, the Companies and the Public Staff filed a Petition to Standardize Electric Service Quality Indices in this docket, in which they proposed a Commission rule formalizing and standardizing the requirements for reporting the reliability of electric utility service by electric public utilities operating in the State. The Companies and the Public Staff noted that, at the time, there were no formal Commission requirements for reporting the reliability of electric utility service by the electric public utilities operating in the State. The Companies and the Public Staff further stated that the proposed rule provided that the electric utilities would report System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) data on a quarterly basis. The Companies and the Public Staff stated that, in drafting the proposed rule, they referred to the Institute of Electrical and Electronics Engineers (IEEE) Guide for Electric Power Distribution Reliability Indices 1366-2012 (IEEE Standard 1366). The Companies and the Public Staff further stated that IEEE Standard 1366 presents a set of terms and definitions that are intended to make reporting practices consistent and to enable comparisons between and among the electric public utilities.

On January 25, 2013, the Commission issued an Order Requesting Comments on Proposed Rule to establish electric utility service quality metrics for all electric public utilities subject to the Commission's integrated resource plan filing requirements under Commission Rule R8-60. Comments and reply comments were filed.

On November 25, 2013, the Commission issued its Order Adopting Rule Establishing Electric Utility Service Quality Metrics and Requiring Filing of Quarterly Reports and Requesting Further Comments. In the Order, the Commission concluded, among other things, that the electric membership corporations (EMCs) should be excluded from the service reliability indices reporting requirements in this rulemaking. The Commission further concluded that DEC, DEP, and Virginia

[1] On April 29, 2013, Progress Energy Carolinas, Inc., became Duke Energy Progress, Inc. (DEP).

[2] The merger transaction closed on July 2, 2012.

Electric and Power Company d/b/a Dominion North Carolina Power (DNCP) should be required to submit SAIDI and SAIFI data on a quarterly basis for the preceding 12 months within 30 days of the end of each quarter beginning with the quarter ending December 31, 2013. The Commission stated that the SAIDI and SAIFI indices are to be reported as outlined in IEEE Standard 1366. Commission Rule R8-40A, Service Reliability Index Reporting, attached as Appendix A to the Order, was adopted effective as of November 25, 2013.

The Commission further stated in its November 25, 2013 Order that it was interested in addressing the adoption of indices relating to customer service satisfaction similar to those required of other utilities subject to the Commission's jurisdiction. The Commission requested that the parties (DEC, DEP, DNCP, and the Public Staff) in this rulemaking discuss the development of customer service satisfaction indices, such as Average Customer Call Answer Time, Complaint Response Time, New Service Installation Factor, Commission Complaint Rate, etc. Comments and reply comments were filed by the parties.

On October 27, 2014, the Commission issued its Order Further Addressing Electric Utility Service Quality Indices (October Order). In the October Order, the Commission, among other things, found it appropriate to require that DEC, DEP, and DNCP file customer satisfaction metrics (automated response system and customer service representative) and 12-month rolling average response time performance (live voice plus technology handled calls) for North Carolina customers on a quarterly basis. The Commission instructed the parties to meet to develop a consensus recommendation for a new Rule to include in Chapter 8 of the Commission's Rules to reflect the inclusion of appropriate customer satisfaction metrics and average response time performance for North Carolina customers by no later than Monday, December 15, 2014. Further, in the October Order, the Commission found it appropriate to require that DEC, DEP, and DNCP file annually the number of new residential service installations and the average number of days in construction per installation for both underground and overhead installations. The Commission directed that the parties meet to develop a consensus recommendation for a new Rule to include in Chapter 8 of the Commission's Rules to reflect the inclusion of appropriate new residential service installation indices for both underground and overhead installations by no later than Monday, December 15, 2014.

On December 11, 2014, DEC, DEP, and DNCP filed a joint motion for extension of time to file the required new Rules. By Order dated December 12, 2014, the Commission granted the motion.

On January 14, 2015, the Public Staff filed a motion for further extension of time for the parties to file proposed new Rules in this docket. The Public Staff requested an extension of time until January 23, 2015, for the parties to file the proposed new Rules. By Order dated January 14, 2015, the Commission granted the motion for further extension of time.

On January 23, 2015, the parties filed their consensus recommendations, as outlined below, on new Commission Rules as required in the October Order. The parties stated that they have worked together to present proposed Rules reflecting the inclusion of appropriate customer satisfaction metrics and average response time performance and the inclusion of appropriate new residential service installation indices for both underground and overhead installations.

Customer Satisfaction Metrics and Average Response Time Performance

The parties noted that they used the quarterly reports that DEC and DEP currently provide to the Public Staff pursuant to Regulatory Condition No. 11.9 to guide the drafting of the proposed Rule. The parties provided a copy of the proposed Rule as Attachment 1 to the January 23, 2015 filing. The parties noted, however, that DEC and DEP have been providing system-wide data, and not North Carolina-specific only data, to the Public Staff under Regulatory Condition No. 11.9. The parties stated that DEC and DEP are presently unable to measure and track North Carolina customer calls and satisfaction independently from South Carolina customer calls and satisfaction. The parties noted that DNCP has also noted that it, too, is unable to measure and track call center performance and customer satisfaction on a North Carolina only basis.

The parties specified that DEC and DEP operate their call centers on a system-wide basis. They noted that North Carolina and South Carolina customers call into the same DEC and DEP call centers, and the call centers do not distinguish between North Carolina and South Carolina customers. The parties noted that the training, policies, and procedures for the call centers do not differ for North Carolina or South Carolina customers, and DEC and DEP use the data they collect to improve, if necessary, Carolinas' call center performance as a whole. They commented that DEC and DEP have determined that configuring its measurement and tracking of call center performance to report on a state-wide, as opposed to a system-wide, basis would presently require additional time and expense.

DEC, DEP, and DNCP stated that they have discussed this issue with the Public Staff. The parties maintained that, based on the inability of the three electric utilities to measure and track this information on a North Carolina basis only, DEC, DEP, and DNCP respectfully request to be relieved of that portion of the October Order at this time. The parties further noted that Piedmont Natural Gas Company, Inc., files its customer call center data on a system-wide basis as well and that Public Service Company of North Carolina, Inc., files information on its North Carolina service territory only, but does not have franchised service territory outside of North Carolina. The parties further noted that the Public Staff, which has monitored DEC's and DEP's call center performance since the close of the Merger between Duke Energy Corporation and Progress Energy, Inc., has indicated that it supports this request.

In addition, the parties commented that DNCP is presently implementing the processes necessary to measure and report customer satisfaction. The parties noted that DNCP has targeted July 1, 2015, for completion of the implementation, and it agrees to provide status updates to the Commission if it needs additional time. The parties stated that, based on that target date, they request a July 1, 2015 effective date for the proposed Rule on call center performance. The parties noted that with a July 1, 2015 effective date, the filing of the first quarterly report would be after the conclusion of the third quarter (July, August, and September) of 2015.

New Residential Service Installation Indices

The parties noted that they have worked together to propose a new Rule as required in the October Order with respect to new residential service installations. The parties included a copy of the proposed Rule as Attachment 2 to the January 23, 2015 filing.

The parties stated that, as noted in the October Order, DEC and DEP do not currently measure and track new residential overhead service installations. The parties noted that DEC and DEP are currently working on implementing the processes required to measure and track new residential overhead service installations so that they can comply with this reporting requirement.

The parties requested that the first annual report due under the new Rule be filed 60 days after the close of the calendar year 2015.

The parties concluded by stating that if the Commission approves the proposed Rules, it will standardize the reporting requirements; however, DEC, DEP, and DNCP urged that the standardization of the reporting requirements should not result in comparisons in performance among the respective utilities. The parties stated that each utility, even DEC and DEP, has operated with different priorities, experiences, customers, and concerns, although DEC and DEP continue to integrate their respective best practices into their operations. The parties asserted that, therefore, even though the utilities are reporting under the same Rule, the performance of one utility should not act as a yardstick to measure the performance of another. DEC, DEP, and DNCP submitted that the data they provide under these Rules better reflects each utility's own performance over time.

The parties requested that the Commission approve the proposed Rules as attached to the January 23, 2015 filing.

The Commission issued an Order on January 29, 2015, allowing interested parties to file comments on the January 23, 2015 consensus filing by no later than February 13, 2015. No party filed comments.

DISCUSSION AND CONCLUSIONS

In the October Order in this docket, the Commission requested the parties to develop a consensus recommendation for new rules to be added to Commission Rule R8, specifically, customer satisfaction metrics, average response time performance, and new residential service installations. The parties were able to file a consensus recommendation, as requested. The Commission has reviewed the January 23, 2015 filing, including the new proposed rules, and finds that it is appropriate to adopt those rules.

IT IS, THEREFORE, ORDERED as follows:

1. That Commission Rule R8-4A, attached hereto as Appendix A, is hereby adopted, effective July 1, 2015, with the first quarterly report to be filed reflecting third quarter of 2015 data.

2. That Commission Rule R8-4B, attached hereto as Appendix B, is hereby adopted, effective March 9, 2015**,** with the first annual report to be filed reflecting calendar year 2015 data.

ISSUED BY ORDER OF THE COMMISSION.
This the _9th__ day of March, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner Bryan E. Beatty did not participate in this decision.

APPENDIX A

Rule R8-4A. CUSTOMER SATISFACTION METRICS AND AVERAGE RESPONSE TIME PERFORMANCE.

(a) Purpose. – The purpose of this rule is to establish standards for measuring and reporting customer call center performance by electric utilities that own and operate electric power systems in North Carolina.

(b) Applicability. – This rule applies to Duke Energy Carolinas, LLC, Duke Energy Progress, Inc., and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power.

(c) Quarterly Reports.

(1) Each electric utility in this State shall file a report on its call center performance on a quarterly basis. The data reported shall be submitted within 30 days of the end of each quarter.

(2) Call center performance reports shall include:

(a) Customer satisfaction with the automated response system and customer service representatives.

(i) Customer satisfaction metrics shall be transaction-based.

(ii) Customer satisfaction metrics shall be based on customers rating their satisfaction with the automated response system and the customer service representatives.

(iii) Results from customers rating their satisfaction with the automated response system and the customer service representatives shall be reported to the Commission for each quarter and the preceding quarters, if any, of a calendar year.

(b) Answer Rate for live voice-handled calls

(i) Total calls answered by a customer service representative as a percentage of total calls received minus technology-handled calls shall be reported on a 12-month rolling average basis.

(c) Average Speed of Answer for live voice- and technology-handled calls.

(i) Average Speed of Answer in seconds shall be reported on a 12-month rolling average basis.

APPENDIX B

Rule R8-4B. NEW RESIDENTIAL SERVICE INSTALLATION INDICES.

(a) Purpose. – The purpose of this rule is to establish standards for measuring and reporting new residential service installations and the average number of days in construction per installation for both underground and overhead installations by electric utilities that own and operate electric power systems in North Carolina.

(b) Applicability. – This rule applies to Duke Energy Carolinas, LLC, Duke Energy Progress, Inc., and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power.

(c) Annual Reports.

(1) Each electric utility in this State shall file a report on its new residential service installations on an annual basis. The data reported shall be submitted within 60 days of the end of each calendar year.

(2) Service installation reports shall include:
   (a) The number of new residential service installations for both underground and overhead installations for the preceding calendar year.
   (b) The average number of days in construction per installation for both underground and overhead installations for the preceding calendar year.

(3) The beginning point for measuring the number of days in construction for both underground and overhead installations shall be the date the builder or customer acknowledges that the building site is ready for the installation work to begin. This occurs after the meter base and load wires have been installed, the site is to final grade, no obstacles impede construction, and any other construction prerequisites have been satisfied.

(4) The ending point for measuring the number of days in construction for both underground and overhead installations shall be the date when new service is energized to the meter base.

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014	)))	ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES

HEARD: Tuesday, May 19, 2015, at 9:30 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Chairman Edward S. Finley, Jr., and Commissioners Bryan E. Beatty, Susan W. Rabon, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC:

Kendrick C. Fentress, Duke Energy Corporation, NCRH 20, Post Office Box 1551, Raleigh, North Carolina 27602

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

Andrea R. Kells, McGuire Woods, LLP, 434 South Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association:

Michael D. Youth, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

Steven Levitas, Kilpatrick Townsend, 4208 Six Forks Road, Raleigh, North Carolina 27612

For Southern Alliance for Clean Energy:

Gudrun Thompson, Southern Environmental Law Center, 601 West Rosemary Street, Chapel Hill, North Carolina 27516

For North Carolina Waste Awareness and Reduction Network:

John D. Runkle, Attorney at Law, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

Tim R. Dodge and Lucy E. Edmondson, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: This is the second phase of the 2014 biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C.A 824a-3, and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions,[1] which delegated to this Commission certain responsibilities for determining each utility's avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings also are held pursuant to G.S. 62-156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by the FERC prescribe the responsibilities of the FERC and of state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain QF status under Section 210 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers. The FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

With respect to electric utilities subject to state jurisdiction, the FERC delegated the implementation of these rules to state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules.

The Commission determined to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate utility-specific avoided cost rates to be paid by the electric utilities to the QFs with which they interconnect. The Commission also has reviewed and approved

[1] Order No. 69, Docket No. RM79-55, FERC Stats. & Regs. 30,128 (1980). See also 45 Fed. Reg. 12,214 (1980).

other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also is a result of the mandate of G.S. 62-156, which was enacted by the General Assembly in 1979. This statute provides that "no later than March 1, 1981, and at least every two years thereafter" the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed therein. Such standards generally approximate those prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The definition of the term "small power producer" for purposes of G.S. 62-156 is more restrictive than the PURPA definition of that term, in that G.S. 62-3(27a) includes only hydroelectric facilities of 80 megawatts (MW) or less, thus excluding users of other types of renewable resources.

Phase One of the 2014 Proceedings

On February 25, 2014, the Commission issued its Order Establishing Biennial Proceeding and Scheduling Hearing. For the purpose of considering various issues raised in the 2012 avoided cost proceeding in Docket No. E-100, Sub 136 (Sub 136 proceeding), the Commission initiated the first phase of the 2014 avoided cost proceeding in advance of the filing of new proposed rates, stating that such rates would be required by a subsequent Commission order. The Commission scheduled an evidentiary hearing to consider changes to the method used to calculate avoided cost payments. Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, Inc. (DEP),[1] Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), Western Carolina University (WCU), and New River Light and Power Company (New River) were made parties to the proceeding.

The following parties filed timely petitions to intervene, which were granted by the Commission: the North Carolina Sustainable Energy Association (NCSEA); the Carolina Utility Customers Association, Inc. (CUCA); the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); the North Carolina Waste Awareness and Reduction Network (NC WARN); the Environmental Defense Fund (EDF); the Southern Alliance for Clean Energy (SACE); the North Carolina Hydro Group; The Alliance for Solar Choice (TASC); the Public Works Commission of the City of Fayetteville; the North Carolina Chapter of the Sierra Club and the Natural Resources Defense Council; and Google, Inc.

Following the evidentiary hearing held July 7-10, 2014, the Commission issued an Order Setting Avoided Cost Input Parameters on December 31, 2014 (Order on Inputs). On January 8, 2015, the Commission issued an Order directing the parties to proceed with the second phase of the E-100, Sub 140 proceedings, focusing on the proposed rates to be filed by DEC, DEP, and DNCP (the Utilities). The Commission indicated its goal was to resolve all remaining issues in the docket based on the evidentiary record and written comments without conducting another full evidentiary hearing for the purpose of receiving expert testimony. Order on Inputs, among other things, established certain parameters by which avoided cost rates should be calculated and required that DEC, DEP, DNCP, WCU, and New River file proposed avoided cost rates 60 days from the issuance of the Order. The Commission established May 4, 2015, as the deadline for both interventions by

[1] DEP converted from a corporation to a limited liability company on August 1, 2015.

interested persons and the filing of initial comments and statements with the Commission; scheduled a public hearing solely for the purpose of taking non-expert public witness testimony for Tuesday, May 19, 2015, at 9:30 a.m.; established deadlines for the filing of reply comments on or before June 8, 2015; and proposed orders on or before July 6, 2015.

Phase Two of the 2014 Proceedings

In accordance with the Commission's January 8, 2015 Order, WCU and New River filed their proposed avoided cost rates on February 27, 2015. On March 2, 2015, DEC and DEP filed their respective Initial Comments and Exhibits (DEC and DEP Initial Comments and Exhibits). Also on March 2, 2015, DNCP filed its Comments, Exhibits, and Avoided Cost Schedules (DNCP Initial Comments and Exhibits).

On April 8, 2015, the Public Staff filed a motion requesting that the Commission: (1) extend the deadline for intervenors to file initial comments from May 4, 2015, to June 8, 2015; (2) extend the reply comment deadline from June 8, 2015, to July 13, 2015; and (3) extend the proposed order deadline from July 6, 2015 to August 10, 2015. By Order dated April 15, 2015, the Presiding Commissioner allowed the motion and extended the deadlines as requested.

On May 19, 2015, the Commission held a hearing to take non-expert public witness testimony. Two public witnesses, Heath McLaughlin and Carson Harkrader, testified.

On May 21, 2015, NCSEA filed a motion requesting that the Commission extend the current deadlines as follows: (1) intervenor initial comments from June 8, 2015, to June 22, 2015; (2) electric utility and intervenor reply comments from July 13, 2015, to July 27, 2015; and (3) proposed orders from August 10, 2015, to August 24, 2015. By Order dated May 29, 2015, the Presiding Commissioner allowed the motion and extended the deadlines as requested.

On June 22, 2015, the Public Staff filed its Initial Statement, NCSEA filed its Initial Comments and Exhibits and the Affidavit of Ben Johnson, and SACE filed its Initial Comments.

On July 22, 2015, DEC and DEP filed a joint motion requesting that the Commission extend the current deadlines as follows: (1) electric utility and intervenor reply comments from July 27, 2015, to August 7, 2015; and (2) proposed orders from August 24, 2015, to September 4, 2015. By Order dated July 24, 2015, the Presiding Commissioner granted the motion and extended the deadlines as requested.

On August 31, 2015, the Public Staff filed a motion requesting that the Commission extend the deadline for proposed orders from September 4, 2015, to September 18, 2015. By Order dated September 1, 2015, the Presiding Commissioner granted the motion and extended the deadline as requested.

On September 9, 2015, the Public Staff filed a letter describing its discussions with DEC, DEP, DNCP, and NCSEA to resolve or narrow differences regarding the development of a form that would establish that a qualified facility had made a commitment to sell its output to a utility, the second prong of the Commission's test for establishment of a legally enforceable obligation (LEO). The Public Staff indicated that these parties had reached agreement on Sections 1-4 of DNCP's proposed Notice of Commitment Form filed with its Reply Comments, but had not reached resolution on Sections 5 and 6. The Public Staff stated that the parties named in the letter would address the unresolved issues regarding the LEO form in their proposed orders.

On September 17, 2015, DEC and DEP filed a letter advising the Commission of their settlement of several issues with NCSEA involving termination rights, the deadline for achieving commercial operation and commencement of term, and the inclusion of interconnection terms in the Terms and Conditions. DEC and DEP also filed a second letter on September 17, 2015, indicating that they and DNCP had discussed proposed language to be contained in Sections 5 and 6 of the Notice of Commitment Forms and had determined that these sections would necessitate DNCP's using a form separate and distinct from the one to be used by DEC and DEP. In its letter, DEC and DEP included a proposed Notice of Commitment Form which they would use, as well as a revised proposed Notice of Commitment Form which DNCP would use.

On October 8, 2015, NCSEA filed a Memorandum of Additional Authority with the Commission. On October 13, 2015, DNCP, DEC, and DEP collectively filed a response to NCSEA's memorandum. In their response, DNCP, DEC, and DEP requested that the Commission reject NCSEA's memorandum as it is inappropriately filed, untimely, and irrelevant. The Commission is well aware of its recent decisions and finds that NCSEA's memorandum is unnecessary to reaching its determination, and, therefore, grants the Utilities' motion to strike.

Between January 1, 2015, and September 9, 2015, 18 consumer statements of position were filed with the Commission. Various other filings and orders in the docket not discussed in this Order remain part of the record of this proceeding.

Based on the entire record of this proceeding, the Commission makes the following

FINDINGS OF FACT

1. It is appropriate for DEC, DEP, and DNCP to be required to offer long-term levelized capacity payments and energy payments for five-year, ten-year, and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity. The standard levelized rate options of ten or more years should include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration. DEC, DEP, and DNCP should offer their standard five-year levelized rate option to all other QFs contracting to sell three MW or less capacity. DNCP should continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in the 2006 biennial avoided cost proceeding in Docket No. E-100, Sub 106 (Sub 106 Order).

2. It is appropriate that DEC, DEP, and DNCP offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, it is appropriate that any unresolved issues arising during such negotiations be subject to arbitration by the Commission at the request of either the utility, the QF or both for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, only if the QF is prepared to commit its capacity to the utility for a period of at least two years. Whether there is an active solicitation underway or not, it is appropriate that QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. It is appropriate that the exact beginning and ending points of an active solicitation be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation is underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

3. As determined in the Commission's Order on Inputs, it is appropriate to require that the Utilities rely on publicly available data sources when calculating the installed cost of a combustion turbine (CT) for avoided capacity purposes and provide clear justifications for any adjustments made to the publicly available data. DEC and DEP have not submitted calculations of the installed cost of a CT for avoided capacity purposes that rely on publicly available data sources.

4. The hypothetical CT utilized by a utility for the purposes of determining avoided capacity rates should be based on the past operational history of the utility, as well as a reasonable expectation of the units the utility anticipates it will construct in the future. DNCP's selection of a CT model with which it has no prior construction or operational experience is inappropriate for use in calculating avoided capacity costs.

5. The useful lives selected by the Utilities for the purposes of this proceeding are reasonable.

6. The methodology utilized by DEC and DEP to apply a contingency factor for the purposes of this proceeding is reasonable and the contingency factor relied on by DNCP from the 2014 Brattle Report is reasonable as applied to DNCP's utilization of the GE 7FA unit for determining avoided capacity costs.

7. As determined by the Commission's Order on Inputs, it is inappropriate to include any economies of scope associated with the construction of more than one CT at the same time in calculating the installed cost of a CT. The Utilities inappropriately included economies of scope when calculating the installed cost of a CT.

8. DEC's and DEP's calculations of avoided energy rates utilizing generation expansion plan scenarios that were selected based on the inclusion of carbon dioxide (CO_2) costs is inconsistent with the Commission's directives from the Order on Inputs.

9. To the extent the Utilities wish to propose changes in the way they utilize forward prices and long-term forecasts, it is appropriate to require that these changes should be made in the Utilities' biennial integrated resource plans (IRPs), and the same approach should be used in their biennial avoided cost filings for that same year.

10. It is appropriate to require that the Utilities recalculate their avoided energy rates using natural gas and coal price forecasts that are developed in a manner consistent with those utilized in their 2014 IRPs.

11. It is appropriate to require that the Utilities recalculate the value of their current hedging programs using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the entire term of the QF power purchase agreement (PPA).

12. The seasonal allocation factors utilized by the Utilities in this proceeding are reasonable. It is appropriate to direct the Utilities, in the next biennial proceeding, to assemble their hourly CT operational data and marginal cost data on a season-specific basis in order to determine whether the allocation factors utilized in this proceeding remain reasonable.

13. It is appropriate to require that DEC and DEP amend the language regarding reporting of production data in Paragraph 5 of their standard PPAs to be consistent with the language agreed to with the Public Staff.

14. The Reduction in Contract Capacity and Reduction in Contract Energy provisions in DEC's and DEP's Terms and Conditions are inconsistent with previous rulings of the Commission and should be rejected.

15. It is appropriate to require that the Utilities not unreasonably withhold consent to a proposed assignment of a standard PPA.

16. The provision in Article 7(a)(vii) of DNCP's proposed Standard Contract granting it a right to terminate a contract where the FERC grants a petition by the utility under PURPA § 210(m) is unnecessary and should be deleted.

17. The language proposed by DEC and DEP in their September 17, 2015, letter providing a reasonable opportunity to cure of 30 days prior to termination of the contract except for fraudulent or unauthorized use of the utility's meter is appropriate and should be included in DEC's and DEP's Terms and Conditions.

18. The proposal by each utility to limit the availability of standard rates to facilities within one-half mile is reasonable, subject to the qualification that two or more QFs under the same or affiliated ownership are eligible for the standard offer rates and terms as long as the combined capacity of those facilities does not exceed five MW. The one-half mile restriction should only apply to facilities that use the same energy resource, and the Utilities should include language stating that the distance between facilities will be measured from the electrical generating equipment of a facility.

19. DEC's and DEP's respective standard contracts should provide that a utility may terminate a contract after 30 months if a QF has failed to achieve commercial operation at any level by that date, provided that the QF should be allowed additional time if the project in question is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner.

20. It is appropriate to require that DEC and DEP amend their standard contracts to clarify that the term begins upon the first date when electrical output is generated by a QF and delivered to the utility.

21. It is appropriate to require that DEC and DEP update Section 1(i) of their Terms and Conditions to allow termination for nonperformance only if the Seller fails to deliver energy to the utility for more than six months.

22. It is appropriate to require that DEC and DEP include a statement that in the event of a conflict between the Terms and Conditions and the interconnection agreement, the interconnection agreement will control.

23. It is appropriate to require that the Utilities update their applicable rate schedules to reflect the utility's payment associated with reactive power for interconnection customers if the power is requested by the utility.

24. It is appropriate to require the Utilities to adopt a form substantially similar to the Notice of Commitment Form submitted by DNCP with its Reply Comments and to require all QFs to utilize such form to establish a LEO.

25. It is appropriate to require that the Utilities place information on their websites clearly showing how to establish a LEO and which departments to contact to negotiate interconnection agreements and PPAs.

26. It is appropriate to require that DEC and DEP revise Paragraph 5 of their respective PPAs to limit their right to request planned operational information from QFs of three MW or larger.

27. WCU's and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved five, ten, and 15-year long-term avoided cost rates for QFs interconnected at distribution should be approved. The changes the Commission has approved herein to DEC's proposed five-, ten-, and 15-year avoided capacity rates should be reflected in the long-term avoided capacity rates that WCU and New River file in compliance with this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in DEC, DEP, and DNCP's Initial Comments and Exhibits and the Initial Statement of the Public Staff.

The Commission found in the Order on Inputs that "DEC, DEP and DNCP should continue to offer long-term levelized capacity payments and energy payments for five-year, ten-year and

15-year periods as standard options." No party in this phase of the proceeding proposed to change the availability of long-term levelized rate options for the specified QFs contracting to sell five MW or less capacity or the availability of five-year levelized rate options to all other QFs contracting to sell three MW or less capacity. In addition to the Order on Inputs, the Commission has consistently concluded in prior avoided cost proceedings that it must reconsider the availability of long-term levelized rate options as economic circumstances change from one biennial proceeding to the next, balancing the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other. The Commission continues to believe that its decisions in past avoided cost proceedings have struck an appropriate balance between these concerns, and that the same approach continues to be appropriate

Based on the foregoing, the Commission concludes that DEC, DEP, and DNCP should each offer long-term levelized rate options of five-, ten-, and 15- year terms to hydro QFs contracting to sell five MW or less and to QFs contracting to sell five MW or less that are fueled by trash or methane from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass. The Commission further concludes that DEC, DEP, and DNCP should offer their five-year levelized rate options to all other QFs contracting to sell three MW or less capacity. With these limitations, long-term contract options serve to both encourage QF development and reduce the Utilities' exposure to overpayments and stranded costs, and should continue to be made available.

DNCP proposed to continue to offer QFs Schedule 19-LMP as an alternative to its Schedule 19-FP, which provides for payment for delivered energy and capacity at avoided cost rates, as determined by the Commission. Under Schedule 19-LMP, DNCP would pay a QF for delivered energy and capacity an equivalent amount to what it would have paid PJM if the QF generator had not been generating. The avoided energy rates paid to the larger QFs with a design capacity of greater than 10 kW would be the PJM Dominion Zone Day-Ahead hourly locational marginal prices (LMP) divided by 10, and multiplied by the QF's hourly generation, while the smaller QFs, who elect to supply energy only, would be paid the average of the PJM Dominion Zone Day-Ahead hourly LMPs for the month as shown on the PJM website. Capacity credits would be paid on a cents per kilowatt-hour (kWh) rate for the 16 on-peak daily hours (7 a.m. to 11 p.m.) for all days. DNCP used the PJM Reliability Pricing Model (RPM) to determine its avoided capacity costs shown as the prices per MW per day from PJM's Base Residual Auction for the Dom Zone. As in prior proceedings, DNCP also adjusted the avoided capacity rate using a Summer Peak Performance Factor (SPPF) as an incentive for QFs to operate during PJM system peak days. The calculation of the SPPF incorporated historical operational data on five individual days during the prior year's summer peak season (defined by PJM as the period from June 1 through September 30). The SPPF varies based on the QF's prior year's operations.

In its Initial Statement, the Public Staff stated that the proposed Schedule 19-FP and Schedule 19-LMP are consistent with the Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, issued on February 21, 2014, in Docket No. E-100, Sub 136 (Sub 136 Order). The Public Staff also stated that the proposed Schedule 19-FP complies with the Commission's Order in the 2010 proceeding.[1] However, the Public Staff noted that DNCP's

[1] See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 127 (2010 proceeding), July 27, 2011.

proposed Schedules 19-FP and 19-LMP do not include a two-year variable capacity rate. The Public Staff recommended that such a rate should be included and made available to QFs otherwise eligible for standard rates.

In the Sub 136 Order, the Commission concluded that, as provided in the stipulations entered into between DNCP and the Public Staff in that proceeding, the parties would further discuss the need for, and structure of, two-year variable capacity rates to be offered by DNCP. No parties in this proceeding raised this issue in their initial statements or reply comments. Nonetheless, the Commission finds that it is appropriate that such a rate should be included and made available to QFs otherwise eligible for standard rates. Therefore, DNCP and the Public Staff shall discuss the structure of two-year variable capacity rates to be offered by DNCP prior to the next biennial proceeding, and DNCP shall include such rates in its next biennial filing.

Based upon the foregoing, the Commission concludes that it is appropriate for DNCP to continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Sub 106 Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP.

The Commission has concluded in past biennial proceedings that QFs not eligible for the standard long-term levelized rates should have the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, the Commission has ruled that any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility, the QF or both for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. Whether there is an active solicitation underway or not, the Commission has held that QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation should be regarded as beginning and ending for these purposes would be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. The Commission has determined that if the variable energy rate option is chosen, such rate may not be locked in by a contract term, but instead shall change as determined by the Commission in the next biennial proceeding.

No party proposed that the Commission alter its prior position on this issue. Therefore, the Commission concludes that DEC, DEP, and DNCP should continue to be required to offer QFs not eligible for the standard long-term levelized rates the option of contracts and rates derived by free and open negotiations or, when explicitly approved by Commission order, participation in the utility's competitive bidding process for obtaining additional capacity. The QF also has the right to sell its energy on an "as available" basis pursuant to the methodology approved by the Commission. Under PURPA, a larger QF is as entitled to full avoided costs as is a smaller QF. The exclusion of larger QFs from the long-term levelized rates in the standard rate schedules was never intended to suggest otherwise.

The Commission has previously ruled that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously utilized complaint process. The Commission concludes that the arbitration option should be preserved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff, the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, NCSEA, the Public Staff, and SACE.

In the Order on Inputs, the Commission found that:

> Because the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data. Data on the installed cost of a CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

In their Initial Comments and Exhibits, DEC and DEP relied on subscription-based data from the Electric Power Research Institute (EPRI) to derive the installed cost estimate for avoided capacity purposes based on the use of a GE Model 7FA unit. This is the same model previously utilized by DEC and DEP in their IRPs and avoided cost proceedings for both simple and combined cycle configurations. DNCP based its underlying installed cost on the cost estimates for the Siemens Model SGT6-5000F (Siemens-5000) CT provided in the 2013 edition of Gas Turbine World Handbook (GTW). For the construction costs and other capital costs, DNCP relied on data from the Brattle Group's May 15, 2014 report, "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," (2014 Brattle Report), which utilized the GE Model 7FA unit as the basis for its costs. DNCP noted that it utilized the Siemens unit in its 2013 and 2014 IRPs, as compared to its use of the GE Model 7FA units in Docket No. E-100, Sub 136 (the 2012 proceeding).

In their Initial Comments, NCSEA and SACE both commented that the Utilities used data from sources that are not publicly available and did not provide adequate justifications for their adjustments to the installed cost of a CT. NCSEA stated that DNCP made an effort to use data from publicly available sources and filed for public inspection the data underlying its avoided capacity cost calculation, with a narrative explanation that identifies the publicly available industry sources on which DNCP relied. NCSEA further stated that on the other hand, DEC and DEP did not initially disclose the data underlying their avoided capacity cost calculations or the sources on which they relied. NCSEA had to obtain this information through the discovery process, which delayed its ability to analyze the avoided cost filings. As such, NCSEA recommended that the Commission require that the Utilities, in future biennial avoided cost proceedings, file as part of their initial filings, the source and data underlying the capacity cost calculations.

The Public Staff did not take exception to the installed costs of a CT proposed by DEC and DEP, based on its assessment that that the projected installed costs were in line with other publicly available estimates of the installed costs for a CT in North Carolina, and were comparable to DEC's and DEP's projected installed CT costs approved by the Commission in the 2012 proceeding, after taking into account adjustments for inflation and the annual increases in CT costs indicated by the U.S. Bureau of Labor Statistics (BLS) Producer Price Index (PPI) for Combustion Turbines and Turbine Generator Sets. The Public Staff did note, however, that DEC and DEP's use of subscription-based data from EPRI, as opposed to the public reports, limits the public availability of the cost information and reduces the transparency of the avoided cost proceeding.

With regard to DNCP's reliance on GTW and adjustments based on the 2014 Brattle Report, the Public Staff noted that DNCP made additional cost adjustments, highlighted in DNCP's Exhibit 1, to the data from the 2014 Brattle Report as follows: (1) removed the equipment cost of selective catalytic reduction; (2) reduced the labor costs, principally with the use of non-union labor; (3) reduced the sales tax rate applicable to Virginia; (4) reduced the gas interconnection costs by assuming a shorter pipeline lateral of one mile, as opposed to the five miles assumed in the Brattle Report; (5) reduced electrical interconnection costs associated with the economies of scale with a four-unit site, as opposed to a two-unit site; (6) adjusted the fuel costs for start-up and inventories to be consistent with the assumptions in the PROMOD model for avoided fuel costs; and (7) removed financing fees that are already included in the economic carrying charge rate calculations. The Public Staff stated that it generally believes the 2014 Brattle Report provides an appropriate basis for a cost estimate and did not take exception to DNCP's adjustments, with the exception of its selection of the Siemens Model CT as opposed to the GE Model 7FA CT.

In its Reply Comments, NCSEA repeated its position that the Utilities did not comply with the Commission's general directive that adjustments to estimates provided in publicly available industry sources be "clearly needed." NCSEA also generally agreed with the Public Staff's appraisal of DNCP's CT adjustments, as well as the Public Staff's position that DNCP had not adequately justified its decision to switch from the GE to the Siemens unit. As such, NCSEA recommended that the Commission direct DNCP to recalculate its avoided capacity cost using the GE Model 7FA CT.

DEC and DEP in their Joint Reply Comments stated that "[t]o some degree, the use of the most robust data available and data that is 'publicly available' are mutually inconsistent steps" and defended their reliance on the EPRI data as providing more robust, specific, and accurate data so that fewer adjustments are necessary. DEC and DEP further indicated that their agreement with EPRI specifically permits them to share the information with parties to regulatory proceedings, as they have done in this proceeding and will continue to do. They further noted that "accurate information of the type required for this proceeding is simply not available from 'off the shelf' resources that completely eliminate the need for reasoned analysis and judgment." With regard to NCSEA's comments that DEC and DEP did not make the underlying data publicly available, DEC and DEP contended that they consider some of the data used to calculate avoided costs to be a trade secret, and, as such, they redacted the information as allowed by the Commission pursuant to G.S. 132-1.2. DEC and DEP stated that they are willing to discuss this issue further with NCSEA to determine if some resolution of NCSEA's concerns can be found, and are willing to make a supplemental filing to report on these discussions.

DNCP in its Reply Comments noted that both the Brattle Report and GTW are "widely recognized, respected, and publicly available industry source[s]" and that it has appropriately tailored the hypothetical CT costs from publicly available industry data consistent with the Commission's Order on Inputs.

The Public Staff in its Reply Comments repeated its concern with DNCP's substitution of the lower costs associated with the Siemens unit from GTW in place of the GE 7FA turbine prices used in the 2014 Brattle Report. The Public Staff noted that the authors of the Brattle Report surveyed the CTs built around the country and concluded that the GE 7FA model is the predominant CT model built and best turbine on which to base its cost of new entry.

DISCUSSION AND CONCLUSIONS

The Commission notes that the installed cost of a CT is a critical input in the calculations of avoided capacity costs using the peaker methodology, and recognizes the importance of an accurate, but also transparent source of information on which to base this value. As such, in the Order on Inputs, the Commission stated "[b]ecause the focus of the peaker method is on a 'hypothetical CT,' for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data." Ordering Paragraph 6 of the Order on Inputs further stated that "in the calculation of the installed cost a CT, [DEC and DEP] shall use data from publicly available industry sources and tailor it only to the extent clearly needed to adapt any such information to the Carolinas." DEC and DEP have not followed this directive.

In this proceeding, the Public Staff found that DEC and DEP's reliance on EPRI data, despite its limited public availability, resulted in avoided capacity costs that were reasonable, and as such, did not take exception with the resulting values. The Public Staff based its recommendation in part on its assessment that that the filed projected installed costs were in line with other publicly available estimates of the installed costs for a CT in North Carolina. If the Public Staff can justify the installed costs of a CT that were filed by DEC and DEP in this proceeding based on publicly available data, it would follow suit that DEC and DEP should be able to calculate installed costs based on publicly available data, as DNCP has clearly displayed is possible. DEC and DEP must already recalculate their avoided capacity costs excluding economies of scope pursuant to Finding of Fact No. 7 below. In doing so, the Commission will continue to require the Utilities to utilize data from publicly available sources when calculating the installed cost of a CT for avoided capacity purposes and to provide clear justifications for any adjustments made to the publicly available data.

With regard to DNCP's use of both GTW and the 2014 Brattle Report, the Commission finds that both of these sources meet the criterion of being publicly available, and concludes that DNCP's continued reliance on them for providing both an installed CT cost, as well as a basis to appropriately tailor the costs for construction of a CT to be constructed in North Carolina or Virginia, is appropriate. The Commission does not, however, support DNCP's ultimate selection of the Siemens unit, as discussed in Finding of Fact No. 4 below or its inclusion of economies of scope as discussed in Finding of Fact No. 7 below.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is contained in DNCP's Initial Comments and Exhibits; the Initial Statement of the Public Staff; the Initial Comments of NCSEA and SACE; and the Reply Comments of DNCP, NCSEA, the Public Staff, and SACE.

In its Initial Statement, the Public Staff stated that it had reviewed the adjustments made by DNCP to the installed costs of a CT from the 2014 Brattle Report and generally found them to be reasonable. However, the Public Staff took exception with DNCP's decision to utilize the cost data for the Siemens Model CT from GTW in place of the GE Model 7FA CT originally utilized by Brattle. For a number of reasons, the Public Staff questioned the likelihood that the Siemens model CT would actually be selected by DNCP for construction and, therefore, recommended that the Commission direct DNCP to recalculate its avoided capacity costs based on a GE Model 7FA CT or a comparable unit from a publicly available industry source. In support of its position, the Public Staff noted that: (1) DNCP utilized a GE Model 7FA CT when calculating its avoided capacity cost in the 2012 biennial proceeding; (2) DNCP does not have a Siemens model CT in its fleet; (3) DNCP does not have experience with the construction and operation of a Siemens model CT; (4) relative to the GE units, a very small number of Siemens CTs have been installed by other utilities over the last five years; and (5) the combined cycle facilities recently placed into service or under construction by DNCP utilize Mitsubishi model CTs.

The Public Staff noted that the 2011[1] and 2014 Brattle Reports prepared for PJM utilized the same GE Model 7FA relied on by DNCP in the 2012 proceeding, in part because it is the predominant turbine type built in PJM. The Public Staff further noted that relatively few Siemens-5000 CTs have come online in a stand-alone configuration as compared to the number of GE-7FA units and cited the 2014 Brattle Report's discussion of its selection process, which did not yield a basis for changing its turbine selection from the GE-7FA.

The Public Staff further noted that DNCP's installed costs decreased by 35%, despite DEC and DEP indicating a small increase in their capacity prices over the same period, and the BLS PPI for Turbine and Turbine Generator Sets indicating an average cost increase of 1.9% per year in the prices of turbines since 2012. As previously noted, DEC and DEP increased their projected CT costs at a rate similar to that reported by the BLS. As such, the Public Staff found DNCP's projected installed cost to be overly conservative and recommended that the Commission direct

[1] Spees, Kathleen, Samuel Newell, Robert Carlton, Bin Zhou, and Johannes Pfeifenberger, Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM, August 24, 2011 (2011 Brattle Report).

DNCP to refile its avoided capacity costs based on a GE Model 7FA unit or a comparable unit from one of the publicly available sources, with appropriate cost adjustments.

DNCP in its Reply Comments noted that the turbine utilized for avoided capacity cost calculations should be the same turbine selected as the least cost option in its IRP. Since DNCP selected the Siemens-5000 as the least cost CT option in the 2014 IRP, it was appropriate for it to use the Siemens-5000 as the hypothetical CT for this proceeding. DNCP also indicated that the Public Staff's reliance on the "fairly simplistic" PPI as a measuring stick was not appropriate, since the PPI simply shows the percentage change in turbine prices from year to year and has limited bearing on the dollars per kW price metric used in avoided cost calculations.

DISCUSSION AND CONCLUSIONS

The Commission recognizes the least cost nature of the IRP planning process and agrees that it is important that the inputs and assumptions utilized in the IRP proceeding carry forward through the following biennial avoided cost proceeding. To the extent DNCP found the Siemens-5000 to be the least cost unit and anticipates constructing those units in the future as part of its current expansion plan, the Commission does not take issue with the selection of the unit. Nonetheless, the values used in avoided costs should be based not only on a reasonable expectation of what actually may be constructed or utilized in the future, but also on the past operational history of the utility.

With regard to the Public Staff's reference to the PPI as an indicator of the reasonableness of the utility's change in avoided capacity costs, the Commission disagrees with DNCP that the use of general indices such as the PPI is inappropriate. In fact, the Commission believes one of the key issues that recur in these biennial proceedings is a utility's reliance on capacity costs based on the specific circumstances that it prescribes, as opposed to reliance on market price indicators that are more widely available. Such public indices are helpful to both the Commission and general public by providing a check as to the reasonableness of the prices and adjustments being proposed by the Utilities. Further, combining data sources or making adjustments to the publicly available data in a piecemeal fashion from multiple data sources calls into question the reliability and integrity of the remaining value. As such, the Commission holds that DNCP should recalculate its avoided capacity costs as shown in Figure 1 of its March 2, 2015 Initial Comments, with the adjustments as shown, but using the turbine costs and capacity rating for a GE Model 7FA CT as originally utilized by the 2014 Brattle Report. This should not only provide DNCP with an internally consistent source for its avoided capacity cost values, but should also recognize the appropriate adjustments that it proposed to make to those values.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, NCSEA, the Public Staff, and SACE.

In its Order on Inputs, the Commission specified that "a reasonable estimate of useful life of a CT … should be included in the calculation of the installed cost of a CT and should be included in the calculation of avoided capacity costs."

In their Initial Comments and Exhibits, DEC, DEP, and DNCP proposed estimates of the useful life of a CT. In its Initial Comments, NCSEA noted that all three Utilities assumed a useful life for a CT that is longer than both the 2014 Brattle Report estimate of 20 years and the confidential EPRI assumption. SACE in its Reply Comments noted that the 2014 Brattle Report "calculated depreciation based on the current federal tax code, which allows generating companies to use the Modified Accelerated Cost Recovery System of 20 years for a [combined cycle] plant and 15 years for a CT plant." SACE further noted the discussions in ISO-New England regarding the appropriate useful life to assume in calculating the cost of new entry for its forward capacity market. Specifically, SACE noted that while power generation plants may physically last for more than 30 years, in financial modeling it is appropriate to use a shorter economic life due to "market risks, including lower cost capacity resources entering market," and the risk of "market interventions that depress prices."[1]

DEC and DEP in their Joint Reply Comments stated that the best reference points to use in determining the useful life of a CT in setting avoided cost rates are: "(1) the actual operating lives of the utility's CT fleet, and (2) the CT useful life assumptions used in setting the utility's base rates." In its Reply Comments, DNCP noted that it used a 36-year useful life because that is the assumed life expectancy of a new utility-owned CT facility based on its most recent asset depreciation studies. In addition, DNCP noted that it used a 36-year expected life to recover the costs of its existing CT plants, and this represents what customers actually pay.

The Commission agrees with DEC and DEP that it is appropriate to consider the costs that North Carolina customers actually bear for a CT and the reasonable expectation of how long a CT should operate in the Carolinas when estimating the useful life for the calculation of the avoided capacity rates. While the consideration of market risk as proposed by SACE is relevant, particularly in RTOs and other restructured regulatory environments, it is less applicable in North Carolina. As such, the Commission finds the useful lives selected by the Utilities to be reasonable for the purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff; the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, NCSEA, the Public Staff, and SACE.

In its Order on Inputs, the Commission directed the Utilities to include in the calculation of the installed cost of a CT "a reasonable contingency adder for a hypothetical plant in relatively early stages of planning." DNCP applied a 10% contingency factor to engineering, procurement, and construction (EPC) costs and a 9% contingency factor to non-EPC costs. DEC and DEP applied a contingency factor that was filed as confidential. DNCP's value was consistent with the contingency factor utilized in the 2014 Brattle Report, while DEC's and DEP's was originally provided in the EPRI data.

[1] Citing Newell, Samuel, and Chris Ungate, Net CONE for the ISO-NE Demand Curve, 3rd Response to Stakeholder Comments and Draft Proposal, Presented to the NEPOOL Markets Committee, February 27, 2014, slides 15-16.

In its in Initial Comments, NCSEA discussed the concept of a contingency factor, stating that its purpose is to cover “unforeseen costs that are likely to arise during construction.” NCSEA cited the discussion of the contingency factors in the following public reports: (1) The 2014 Brattle Report utilized by DNCP; (2) the Cost Report prepared by Black and Veatch for the National Renewable Energy Laboratory (NREL),[1] which provided a range of contingency factors based on the design stage of a facility; and (3) the 2013 EIA report entitled Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, which included a 10% contingency factor on EPC costs as well as an additional 20% allowance for owner’s costs and contingency, excluding financing.[2]

NCSEA stated that the reasonableness of a particular contingency factor would vary depending upon the specific context in which the factor will be used. It noted that while a 5% to 10% contingency factor might be adequate for internal purposes at the late stages of the planning process, a higher contingency is necessary for the purposes of avoided cost calculations “consistent with the Commission’s directive that the contingency factor reflect ‘a hypothetical plant in relatively early stages of planning.’” NCSEA stated that an understated contingency factor reduces an electric utility’s avoided cost, which may discourage QF development and, therefore, fail to meet PURPA’s objective of ratepayer indifference. As such, NCSEA recommended that the Commission direct the Utilities to include a contingency factor in the range of the industry sources it discussed – 15% to 20%, or 30% if the Commission approves DNCP’s use of the Siemens CT.

In its Initial Statement, the Public Staff did not take exception to the contingency factor utilized by DEC and DEP, due in part to its general acceptance of the reasonableness of the overall installed costs of capacity proposed by the utility. The Public Staff did, however, state that if the Commission approves DNCP’s selection of the Siemens CT, a number of other adjustments such as the applicable contingency factor associated with the facility, capital spare parts, and O&M would need to be adjusted to reflect DNCP’s limited experience with the unit.

In its Reply Comments, NCSEA recommended that the Commission direct DEC and DEP to adjust the contingency factor upward to 15-20%, which it believed is more appropriate for a plant in relatively early stages of planning. SACE stated in its Reply Comments that it concurred with the Public Staff that the combination of DNCP’s limited experience with the Siemens unit and “the very rough nature of the cost estimate” supports the use of a higher contingency factor in determining avoided capacity costs.

In its Reply Comments, DNCP stated that “constructing a simple cycle CT plant is not a new and risky endeavor, but a well-known and documented construction process. DNCP contended that switching from GE to Siemens turbines does not change the overall risk profile of the potential project; thus, the same percentage level of contingency is adequate.” As such, DNCP argued that no adjustments to its estimated avoided capacity costs are needed, including its use of a Siemens as the hypothetical CT. DNCP stated that its procurement group is active and

[1] Cost Report: Cost and Performance Data for Power Generation Technologies, prepared by Black & Veatch, prepared for NREL, February 2012, p. 8, available at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf. Included as Exhibit 3 to NCSEA’s Initial Statement.

[2] Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, prepared by United States Energy Information Administration (EIA), April 2013, Sections 8 and 9, available at: http://www.eia.gov/forecasts/capitalcost/.

experienced in the power plant equipment market and maintains regular dialogue with key manufacturers and vendors of equipment. DNCP also explained that it has an experienced construction management department and has historically been able to plan, design, construct, operate, and maintain CT facilities on-time and in-line with its budget estimates.

DEC and DEP stated in their Joint Reply Comments that the contingency adder they utilized is reasonable because it is based on their actual experience in constructing CTs in both simple cycle and combined cycle configurations in the Carolinas and is consistent with industry standards for how contingency adders are defined and utilized.

DISCUSSION AND CONCLUSIONS

The Commission believes that it is appropriate to continue to require the inclusion of a reasonable contingency adder for a hypothetical plant in the relatively early stages of planning. The amount of this adder should be adjusted based a utility's experience in the construction and operation of a specific unit, current market conditions for skilled labor and materials, and other relevant factors. As such, the Commission accepts the methodology utilized by DEC and DEP to calculate its contingency adder as reasonable for this proceeding, and finds that the contingency factor relied on by DNCP from the 2014 Brattle Report is acceptable as applied to DNCP's utilization of the GE 7FA unit for determining avoided capacity costs. To the extent necessary, DEC and DEP shall adjust its contingency adder to reflect its use of publicly available data when recalculating its avoided capacity costs, rather than relying upon EPRI data.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff; the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, and NCSEA.

In its Order on Inputs, the Commission provided that when calculating the installed cost of a CT, the Utilities may include economies of scale for up to four CTs constructed on the same site; but not any economies of scope associated with constructing more than one CT at a time. Further, the Commission specified that "to the extent a utility applies economies of scale related to the installed cost of multiple CTs at a single location, the utility should provide detail as to the economies being achieved and the specific components of the EPC contract or balance of plant to which the efficiencies are being applied."

In their initial filings, the Utilities utilized economies of scale for the construction of four CTs on the same site. DEC and DEP stated that the EPRI data they utilized included both economies of scale and scope for a four-unit site. They further stated that they excluded economies of scope by eliminating the assumption that four CTs were contracted under a single EPC contract simultaneously at the same site. Instead, they assumed that they could purchase at least two turbines at the same time to be placed at different locations within their various service territories. The Brattle Report on which DNCP relied assumed "two turbines at one site to capture savings from economies of scale."[1] DNCP also made further adjustments to the data to reflect additional

[1] 2014 Brattle Report at 8.

economies of scale related to its electrical and gas interconnection costs to correspond to a four-unit rather than a two-unit site.

NCSEA and SACE both filed comments stating that the Utilities misapplied the Commission's directive with regard to economies of scope. NCSEA noted that DEC's and DEP's calculation assumes the construction of four units at two sites, relying on the EPRI 2 x 2-unit site data. NCSEA stated:

> Rather than starting with the 2-unit data or the 4-unit data, … DEC and DEP could have started with the EPRI and B&M 1-unit data and adjusted those cost estimates downward to reflect the estimated impact of economies of scale within the categories for which DEC and DEP assert that such economies are realized – the cost of land, site preparation work, roads, buildings and structures, as well as general plant facilities.

Further, in his affidavit submitted on behalf of NCSEA, Dr. Ben Johnson noted that adjustments to include economies of scale should be computed "net of the additional carrying costs (capital costs and property taxes) that would be incurred by acquiring a larger parcel of land, clearing and preparing a larger site, building additional roads, and constructing larger buildings and structures prior to the time when these are needed for the additional units." With regard to DNCP, NCSEA stated that since the Brattle Report assumed that both turbines were to be constructed at the same time, the cost estimates in the Brattle Report also included cost savings from economies of scope that should have been excluded. It also challenged the other adjustments made by DNCP as being unjustified.

In their Joint Reply Comments, DEC and DEP stated that the type of data available publicly makes it impossible to isolate economies of scale from economies of scope to an empirical certainty, and that sound judgment is required. They contended that "[t]he question for the Commission should not be what equation was used, but whether the result complies with the PURPA standard of providing an avoided cost payment that makes customers indifferent as to whether the capacity is provided by a CT or a QF."

DNCP in its Reply Comments stated that it since it relied on the 2014 Brattle Report in its estimation of a hypothetical CT's construction costs, without knowing the underlying assumptions and derivation of the Brattle Report numbers, it was impossible to know whether the estimates included cost savings from economies of scope. Therefore, DNCP did not propose any adjustment to this data to remove the impacts of economies of scope. DNCP noted that "if the Commission determines that an adjustment is required, then the adjustment should be limited to the 'mobilization and start-up category' of its detailed cost sheet because that would be the only cost incurred based on the (Commission- required) assumption of installing the turbines one at a time (and such costs would in fact be minimal)." DNCP further noted that with respect to its further adjustment of the electric and gas interconnection costs to assume a four-unit site, it did not simply cut the estimate in half, but instead made specific adjustments to the electrical interconnection costs to remove electric transmission network upgrade costs and reduced the assumed length of the natural gas lateral from five miles to one mile to better approximate the actual expected interconnection costs.

DISCUSSION AND CONCLUSIONS

DEC and DEP have submitted data that includes economies of scope for purchase of at least two turbines at the same time in contravention of the Commission's Order on Inputs. Likewise, DNCP also failed to follow the Commission's Order when it relied upon data that assumed two turbines were to be constructed at the same time. The Commission clearly stated in Ordering Paragraph 7 of its Order on Inputs that "DEC, DEP and DNCP shall not include any economies of scope associated with the construction of more than one CT at the same time." DEC and DEP state as justification for their non-compliance that "the question for the Commission should not be what equation was used, but whether the result complies with the PURPA standard of providing an avoided cost payment that makes customers indifferent as to whether the capacity is provided by a CT or a QF." The Commission ruled on this issue in its Order on Inputs and determined that the inclusion of economies of scope in the installed cost of a CT is inappropriate when determining avoided capacity costs under PURPA. Therefore, it follows from the Commission's Order that such an inclusion does not comply with the PURPA standard of providing an avoided cost payment that makes customers indifferent as to whether the capacity is provided by a CT or a QF.

The Utilities shall be required to recalculate the installed costs of a CT excluding economies of scope. The Utilities have stated that it is difficult to separate the permitted adjustments for economies of scale from adjustments made for economies of scope. The Commission notes that, in addition to stating that the calculation of the installed cost of a CT "shall not include any economies of scope", Ordering Paragraph 7 of the Order on Inputs also states that the calculation shall include "economies of scale for up to four CTs constructed on the same site." Thus, if the Utilities are unable to establish a proper methodology to include economies of scale without including economies of scope in their calculations, they are permitted, pursuant to the Order on Inputs, to submit an installed CT cost based on the installation of one CT at a single site without adjustments for economies of scale or scope.

With regard to economies of scale, when recalculating the installed costs of a CT, the Utilities shall take note of the affidavit of Ben Johnson, filed on behalf of NCSEA, stating that adjustments to include economies of scale should be computed net of the additional carrying costs (capital costs, property taxes, etc.) that would be incurred by acquiring a larger parcel of land, clearing and preparing a larger site, building additional roads, and constructing larger buildings and structures prior to the time when they are needed for the additional units. The Commission finds merit in this argument. The Utilities should continue to provide detail as to the economies of scale being achieved and the specific components of the EPC contract or balance of plant to which the efficiencies are being applied, while also taking into account any carrying costs associated with the economies of scale.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff; the Initial Comments of NCSEA; and the Joint Reply Comments of DEC and DEP.

In the Order on Inputs, the Commission held that for the purpose of calculating avoided energy rates, the generation expansion plans used in the avoided production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs. The Commission further found that CO_2 costs "are not sufficiently certain to be included in avoided costs at this time."

The Public Staff in its Initial Statement noted that DNCP utilized a generation expansion plan to calculate avoided energy costs that did not include carbon costs. However, DEC and DEP in their avoided energy cost calculations utilized generation expansion plans that were selected based on inclusion of a CO_2 emissions price, as reflected in certain scenarios in their 2014 IRPs, while at the same time, the cost of CO_2 abatement was excluded from the avoided energy calculations. The Public Staff stated that this mismatch of generation expansion plans and avoided energy inputs could distort the avoided energy calculations and result in a miscalculation of avoided energy costs. For example, the inclusion of carbon prices in IRP modeling may result in the selection of new nuclear units in the generation expansion plan, as it did with DEC's base case in its 2014 IRP.[1] Since the capital costs associated with new nuclear units are not included in the avoided energy calculations, the relatively low cost energy provided from the new nuclear results in an underestimation of avoided fuel costs. The Public Staff therefore recommended that the Commission direct DEC and DEP to recalculate their avoided energy rates utilizing generation expansion plan scenarios that do not include the costs of CO_2. NCSEA raised similar concerns, noting that under DEC and DEP's approach "the QF has the potential to be penalized by the cost of carbon in the avoided energy calculation, without being credited with the avoidance of such cost by the utility."

In their Joint Reply Comments, DEC and DEP stressed the distinction between their "development of a long-term resource plan that is robust and accounts for the possibility that carbon costs may be imposed in the future with the intent of PURPA, which is to calculate avoided costs based on currently known and measureable costs that are avoided because of the purchase of power from the QF." They stated that to the extent carbon costs actually have been incurred, these costs are included in their avoided costs calculations.

DISCUSSION AND CONCLUSIONS

The Commission notes the extended discussion on this issue in the Order on Inputs and reiterates its determination that the generation expansion plans used in avoided cost production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs. DEC's and DEP's calculation of avoided energy rates utilizing generation expansion plan scenarios that were selected based on the inclusion of the CO_2 costs is inconsistent with the Commission's directives from the Order on Inputs. Therefore, DEC and DEP shall recalculate their avoided energy rates utilizing generation expansion plan scenarios that do not include the costs of CO_2. In their 2014 IRPs, DEC and DEP evaluated the portfolios identified as part of their screening analysis under a No Carbon Scenario, and found that under the base case sensitivity for fuel prices, Portfolio 1 had the lowest present value revenue requirement of the

[1] DEC Integrated Resource Plan (Annual Report) filed on September 1, 2014, in Docket No. E-100, Sub 141.

portfolios considered.[1] The Commission concludes that DEC and DEP should recalculate their avoided energy rates utilizing the generation expansion plans resulting from Portfolio 1 under the No Carbon Scenario.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 – 10

The evidence supporting these findings of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff; the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, NCSEA, the Public Staff, and SACE.

In its Initial Statement, the Public Staff stated that DEC and DEP did not use the same methodology for forecasting natural gas prices in their avoided energy calculations that they used in their 2014 IRPs. In this proceeding, DEC and DEP incorporated ten years of future spot prices combined with their traditional fundamental forecast for the years eleven through fifteen, while in their 2014 IRPs, they relied on five years of forward price data. The Public Staff stated that the change results in a significant difference in the slope of the natural gas price forecasts between 2020 and 2025 in the IRPs and the avoided cost filing, respectively. The Public Staff further noted that in the 2012 IRP[2] and 2012 avoided cost proceeding, DEC used two years of forward price data combined with 24 months of transitional data that it merged with its long-term fundamental natural gas price forecast.

The Public Staff noted that in the Order on Inputs, the Commission emphasized the relationship between the generation expansion plan developed in the IRP and the determination of avoided energy costs that reflect current and future generation units combined with future renewable generation, demand-side management, and energy efficiency resources. The Public Staff contended that the use of five years of forward prices is acceptable, but the market for ten-year futures is much smaller and relatively illiquid. Further, the Public Staff discussed the differences between spot price forecasts and forward prices and the different roles they serve. The Public Staff stated its view that an overreliance on forward price data can call into question the reliability of the long-term forecasts. The Public Staff also expressed similar concerns over DEP and DEC's use of longer-term forward prices for coal, considering the non-fungible nature of the fuel and the lack of transparency in the coal markets, resulting in decreased confidence in the forecast over time. As such, the Public Staff recommended that the Commission direct DEC and DEP to reconstruct their natural gas and coal price forecasts using only five years of forward price data, consistent with the approach utilized in their 2014 IRPs, and to recalculate their avoided energy costs using the updated fuel price forecasts.

NCSEA had similar concerns regarding the changes in future fuel prices. In its Initial Comments, NCSEA discussed the history of fuel prices for both coal and natural gas and noted that each of the Utilities developed its fuel price forecasts by using a different method from that used in its 2014 IRPs. In addition, NCSEA noted that DEP relied on the same fuel price forecasting method used in its 2014 IRP in its application for a certificate of public convenience and necessity (CPCN) to construct the 84 MW Sutton blackstart CT, which was filed on April 25, 2015, in

[1] DEC and DEP IRP (Annual Report) filed on September 1, 2014, in Docket No. E-100, Sub 141, at pp. 54-55.

[2] DEC Integrated Resource Plan (Annual Report), filed September 1, 2012, in Docket No. E-100, Sub 137.

Docket No. E-2, Sub 1066. NCSEA also stated that DNCP relied more heavily on futures market data during the first seven years of the planning period. NCSEA concluded that by changing the methodologies from those used in their 2014 IRPs and placing greater emphasis on futures market data, the Utilities developed much lower avoided energy cost estimates than they would have if they had used the same assumptions and methodology used in their 2014 IRPs. NCSEA therefore requested that the Commission direct the Utilities to recalculate their avoided energy costs using the future fuel prices developed for their 2014 IRPs.

In its Reply Comments, the Public Staff noted that DNCP made changes in its weightings of the fundamental forecast and futures market data, resulting in different avoided energy cost rates than its approach utilized for developing fuel forecasts in its 2014 IRP. The Public Staff repeated its concerns about the appropriateness of utilizing forward prices for natural gas and coal in developing long-term price forecasts, stating that “some use of futures market data might be appropriate for the short-term, but only to the extent that the markets are viewed as liquid and the volumes being transacted reflect an active market for the commodities in question.” The Public Staff noted that “while forward market prices may provide a snapshot of current future prices, they do not represent the same level of analysis and consideration given to the development of long-term forecasts, as performed by the EIA, Moody’s Investor Services, Inc., Global Insight, Inc., and other firms whose expertise is in forecasting.” Further, the Public Staff noted that the utilization of forward prices is not consistent with the fuel procurement practices of the Utilities and thus does not provide an accurate representation of the Utilities’ future fuel costs.

NCSEA in its Reply Comments noted that the Utilities did not propose to change their fuel forecasting methods in the first phase of the proceeding, despite the purpose of that phase of the proceeding being to determine appropriate input parameters for avoided cost calculations. NCSEA agreed with the Public Staff that DEC and DEP should use no more than five years of futures market data when constructing their fuel price forecasts, noting that this approach is not only consistent with DEC’s and DEP’s IRP forecasts but is also more consistent with DEC’s and DEP’s fuel procurement practices, citing to the Fuel Procurement Practices Report filed by DEC in December 2014. NCSEA disagreed, however, with the Public Staff’s recommendation that DEC and DEP update their 2014 IRP forecasts; NCSEA instead recommended that DEC and DEP’s actual 2014 IRP fuel forecasts be used to recalculate their avoided energy costs.

In its Reply Comments, SACE agreed with the Public Staff’s and NCSEA’s criticisms of the fuel price forecasts proposed by DEC and DEP and recommended that DEC and DEP use only three years of NYMEX Henry Hub natural gas futures prices and then transition to long-term forecasts when calculating avoided energy.

DEC and DEP in their Joint Reply Comments indicated that they have employed the same methodology in this proceeding that they have employed historically to calculate their avoided energy costs, contrary to the assertions by NCSEA and the Public Staff. DEC and DEP agreed that in their 2014 IRP filings, they relied on market data for the first five years and then used the fundamental forecast for the longer-term fuel prices. In the current proceeding, however, DEC and DEP found that improved liquidity in the market supported the use of market data over ten years instead of five. They indicated that their ability to acquire transactable price quotes for a ten-year period from four separate market participants demonstrates that sufficient market liquidity exists in the market to justify this approach. DEC and DEP stated that NCSEA’s statement that DEP relied on fuel prices to justify the Sutton Blackstart CT Project is incorrect, stating that the project was justified exclusively for operation requirements, with no reliance on fuel costs.

DEC and DEP further stated that they have used and will continue to use market pricing to the extent reliably available, and will use forecasted fuel information for periods where market data is not available or is unreliable. They added: "The markets, not DEP or DEC, establish whether price transparency and liquidity exist, determined by the simple market-based test of whether there are willing sellers and buyers and whether there is a reasonable 'spread' between the bid and ask price action." DEC and DEP disagreed with the Public Staff's argument that "futures" prices are determinative of long-term "forward" supply prices. They stated that futures are valued to account for or insure against price movement of the underlying asset, and therefore serve as a risk mitigation, or hedging, mechanism. Further, they stated that "futures prices are traded as financial instruments that value the anticipated volatility of the underlying asset class – not the forward transactional value of the asset class." They stated that their price forecasts have always been based on the value of forward sale and purchase commitments, not futures contracts. They also challenged the Public Staff's statement that the market for ten-year futures is relatively illiquid, noting that they do not obtain gas for ten-year deliveries using a ten-year futures contract; and that fewer market participants does not mean a market has become illiquid. Instead, DEC and DEP argued that at this time, fewer market participants are using long-dated futures contracts because there are better risk mitigation alternatives, such as the over-the-counter financial "swaps."

In its Reply Comments, DNCP discussed the different approaches it utilized in forecasting energy prices in its IRPs as compared to avoided cost calculations. DNCP stated that using forward market prices for a shorter time period is acceptable for IRP modeling, where new resource options are economically compared to each other, in the development of a resource expansion plan. However, for avoided cost pricing purposes, using forward market prices for a longer time period is appropriate because DNCP is determining actual contract rates that may be paid to a contracting QF, and this approach provides a more accurate representation of its avoided energy costs at the time of the filing, as compared to the prices derived from long-term fundamental forecasts. In addition, DNCP noted that it disagreed with NCSEA's recommendation that it use the same fuel price forecasts used in the 2014 IRP, since those rates would have been nearly a year out of date at the time of filing.

DISCUSSION AND CONCLUSIONS

The Commission recognizes the changing nature of the natural gas market and the fact that lower natural gas prices in the short- and long-term will result in benefits to ratepayers in the form of lower-cost electricity rates. In addition, the Commission notes that forecasts, while not directly derived solely from market prices, are highly influenced by market activity, and that changes in the liquidity and trading prices in the natural gas markets over the long-term are being incorporated into long-term forecasts. In the context of both the avoided cost and IRP proceedings, recognition of these changing markets is appropriate. The Commission acknowledges that forecasting natural gas and coal prices over the next fifteen years is challenging and that forward market prices may provide a better snapshot of prices over the near and short-term future. However, forward market prices do not reflect the same level of analysis and consideration given to the development of long-term forecasts, as performed by firms whose expertise is in long-term forecasting. The

Commission finds that the increased reliance on forward prices for natural gas by the Utilities in their 2014 IRPs, and on coal prices by DEC and DEP, adequately captures some of these changing market conditions at this time. This determination also reflects the important relationship that exists between the biennial avoided cost proceeding and the IRP, and helps to maintain internal consistency between these proceedings. As such, the Commission agrees with the Public Staff that DEC, DEP, and DNCP should recalculate their avoided energy rates using natural gas and coal price forecasts that are constructed in a consistent manner with those utilized in their 2014 IRPs.

Furthermore, as noted by the Public Staff, the Utilities have increasingly placed greater emphasis on futures market data in both of the last two biennial IRP and avoided cost proceedings. However, rather than utilizing the same approach in both of the 2012 proceedings, DEC and DEP changed their approach between the 2012 IRPs filed in September 2012 and the avoided cost filings in November 2012. Similarly, in 2014, DEC and DEP changed their approach between their September 2014 IRP filings and the filing of their 2014 avoided cost rates in March 2015. In the Order on Inputs in this Docket, the Commission emphasized the relationship between the IRP and avoided costs and the need for their inputs and assumptions to be consistent. As such, the Commission finds that to the extent the Utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in future IRP and avoided cost proceedings, those changes should first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is contained in the Initial Comments and Exhibits of DEC, DEP, and DNCP; the Initial Statement of the Public Staff; the Initial Comments of NCSEA and SACE; and the Reply Comments of DEC, DEP, DNCP, NCSEA, the Public Staff, and SACE.

In the Order on Inputs, the Commission found that:

> [T]here are fuel price hedging benefits associated with solar generation, as well as hydroelectric, landfill gas, and other renewable generation because purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that needs to be purchased. It is appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation.

The Commission then concluded that the Utilities should value hedging benefits only over the term hedging is actually used, and that the Utilities should include the fuel hedging benefits associated with purchases of renewable energy in their avoided energy cost rates.

In their Initial Statements and Exhibits, DEC and DEP used forward market indices for the years 2015 through 2025 to determine their respective avoided energy costs. They then accounted for hedging costs by using the "ask" price, rather than the mid-point in developing their fuel price forecasts. DNCP indicated that it included in its avoided energy costs the gas broker transaction costs and financing costs fees it expected to avoid as a result of purchases from renewable energy suppliers.

The Public Staff in its Initial Statement indicated that it does not believe that the avoided energy costs of the Utilities fully reflected the fuel price hedging benefits that result from the substitution of renewable generation for fossil-fueled generation. It further stated that "avoided energy costs should reflect both projected fuel costs and the fuel price hedging benefits of renewable generation for each year of the contract." As an illustration of this approach, the Public Staff utilized the Black-Scholes Option Pricing Model to evaluate Henry Hub natural gas options, stating that these financial instruments over terms of less than three years are publicly traded in a robust marketplace with transparent prices. Using this evaluation, the Public Staff determined that a net option price, the price of a call option minus the price of a put option, for "at-the-money" Henry Hub natural gas options, is approximately $0.04 per dekatherm for the 12- and 24-month hedge terms used by the Utilities. The Public Staff then converted the $0.04 per dekatherm net option price to a hedge value of 0.028 cents per kWh. The Public Staff recommended that the Commission direct the Utilities to recalculate the value of their current hedging programs using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year that renewable generation helps the utility avoid fuel purchases associated with traditional generation.

NCSEA in its Initial Comments found that the Utilities' hedging calculations substantially understated the hedging benefits of renewable generation and did not comply with the Order on Inputs. NCSEA stated that a different methodology must be used in order to provide a reasonable allowance for hedging consistent with the Commission's directive, and contended that the allowance must be provided in each year of the contract term to reflect the fuel price hedging benefit year to year. It further noted that "a valid analysis of hedging benefits must consider the full level of risk that can be avoided by customers over the appropriate time horizon not simply the portion of that risk against which the utility is actually hedging." SACE noted several similar issues with the hedging calculations proposed by the Utilities, including that the hedge value should be accounted for each year of a QF contract.

In its Reply Comments, SACE evaluated the Public Staff's recommendation that the Utilities use the Black-Scholes Option Pricing Model or a similar method to calculate the hedge value of renewable energy purchases. SACE stated that the input parameters and calculation assumptions for the Black-Scholes Model must be carefully considered. SACE also stated that while some inputs can be easily obtained, the assumed annual volatility rate is a critical parameter for two reasons: (1) small changes in this value have significant effects on the calculated value, and (2) it is impossible to know what the volatility of the spot price of natural gas will be over a future time period. With these parameters in mind, SACE indicated its support of the Public Staff's proposal to use the Black-Scholes Model to determine the hedging value of renewable generation.

NCSEA in its Reply Comments stated that it reviewed the alternative method proposed by the Public Staff, and while it did not take issue with the approach, it did take issue with the "risk-free interest rate" used by the Public Staff in calculating the hedge value. The Public Staff in its hypothetical example used 1% as the rate; and NCSEA proposed that a rate of at least 3.10% be used in the calculation, which it stated is consistent with the range of risk-free interest rates used by the Utilities in developing cost of equity estimates in their respective most recent rate case proceedings. NCSEA agreed with the Public Staff and SACE that the hedge value should be included in each year of the entire term of the QF PPA. In addition, NCSEA noted that the calculation of the fuel price hedging benefit provided by QF generation is a topic being discussed across the country. As such, NCSEA requested that, in addition to approving the Public Staff's proposed methodology (corrected to incorporate NCSEA's recommendation regarding interest rate and hedge value), the Commission indicate its willingness to revisit this issue in future proceeding as further methodologies emerge.

In their Joint Reply Comments, DEC and DEP stated that rather than using a forecasted approach, they "utilized a 10-year liquid market approach, which uses actual, quoted transaction costs rather than forecasted, speculative information." DEC and DEP noted that establishing a hedge value is a difficult exercise, and while many approaches exist, they are the only parties in the proceeding to offer a concrete method using actual prices received from actual market participants, as opposed to the "use of selective input variables inserted into computer models, such as the Black-Scholes."

DNCP in its Reply Comments raised questions regarding the Public Staff's proposed use of an option pricing model such as the Black-Scholes Model, contending that it was a very nebulous and theoretical concept that would require difficult modeling and numerous debatable assumptions. DNCP further stated that it is not aware of any jurisdiction that has employed this methodology for the calculation of avoided costs. DNCP instead proposed an alternative method that estimated the fuel hedging costs, which it described as brokerage charges related to gas financial transactions that could be avoided with increasing amounts of renewable energy purchases. Lastly, DNCP agreed that it is reasonable to include the fuel hedging savings in all years of the forecast, not just the first year.

DISCUSSION AND CONCLUSIONS

The hedging value of renewables was discussed at length in the first phase of this proceeding, and while the Order on Inputs directed the Utilities to include a value for hedging, it did not specify a particular method to be used. The proposals made by the Utilities have merit in that they recognize actual prices in the market for long-term gas prices or the estimated transaction fees that could be avoided, but they fail to capture the full hedging benefits that renewable energy purchases can provide by reducing ratepayers' exposure to fuel price volatility and providing price stability. Furthermore, the Commission is not persuaded that DEC and DEP's use of "ask" prices in forward markets provides a reasonable estimate of the value from hedging. Likewise, the Commission is not persuaded that DNCP's use of transaction fees is the appropriate method to estimate the hedge value of stable fuel prices with solar and renewable generation.

As such, the Commission finds that it is appropriate for the Utilities to utilize the Black-Scholes Model or a similar model to determine the hedging value of renewable generation. The Commission notes that during the late 1990s, DEC and DEP each conducted a request for proposals (RFP) that resulted in various option-based power bids that necessitated the Utilities to incorporate a Black-Scholes Model. These models relied on price volatility estimates, risk-free discounts, and strike prices. DEC incorporated such models in its RFP evaluation in the application of Rockingham Power, LLC, for a CPCN in Docket No. SP-132, Sub 0[1] and in DEP's application to

[1] Public Staff Confidential Report on Duke Energy's Corporation's Bidding Process, pp. 8-11, filed May 19, 1999.

build CT generation capacity in Wayne County in Docket No. E-2, Sub 669.[1] The Commission further finds that the fuel hedge value should be included for each year of the entire term of the QF PPA. With regard to NCSEA's concern over the appropriate risk-free interest rate utilized in the calculation, the Commission does not take a position with regard to a specific percentage, but notes that the appropriate risk-free rate selected for use by the Utilities should reflect the time-value of money related to buying the hedge position, which in turn should be tied to their current natural gas hedging practices.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in Exhibit 4 to the Initial Statements of DEC and DEP, the Initial Statement of the Public Staff, the Initial Comments of NCSEA, and the Reply Comments of NCSEA and DEC and DEP.

In its Initial Statement, the Public Staff noted that DEC, DEP, and DNCP used an allocation process to weight their avoided capacity costs between summer (on-peak) and non-summer (off-peak) months. DEC and DEP have historically included such an allocation in weighting their avoided capacity costs to determine their avoided capacity rates and have designed the allocation to reflect the historical percentage breakdown of annual CT production between the on-peak and off-peak seasons. In response to the Public Staff's data requests, both DEC and DEP provided information indicating that their CT fleets were used more during summer months than winter months. The data supported the 60%/40% weighting for summer and non-summer months for the proposed avoided capacity rates under DEC Option B and DEP Options A and B, and the 80%/20% (summer/non-summer) weighting for DEC Option A.

The Public Staff noted that DNCP also applied a 60%/40% summer/non-summer allocation to its avoided capacity costs for similar reasons to those stated by DEC and DEP. In response to the Public Staff's data request, DNCP further stated that the capacity "value" was more critical during the summer peak load times. However, DNCP also acknowledged the occurrence of winter peak loads and indicated that they tended to be more volatile. DNCP further indicated that PJM has proposed to revise its capacity market rules to address the winter peak loads and fuel issues, recognizing the importance of system reliability during both winter and summer peak seasons. DNCP indicated that the FERC was reviewing PJM's proposal, and that DNCP anticipates reviewing the summer/winter allocation going forward as the PJM capacity market proposal is finalized and approved.

The Public Staff indicated its interest in further evaluating the differences in the winter and summer peak loads, how the Utilities meet their peak load obligations for each season, and the cost impacts associated with the distinct differences in the need for, and character of system capacity. It further noted that given the peak load conditions that have been observed in North Carolina in both the winter and summer seasons, the continued use of a seasonal allocation of avoided capacity costs in the manner proposed by the Utilities may need further review. Therefore, the Public Staff recommended that in the next avoided cost proceeding, the Utilities assemble their

[1] Public Staff Confidential Report on Carolina Power and Light Company's Bidding Process, pp. 5-11, filed October 30, 1998.

hourly CT operational data and marginal cost data on a season-specific basis to determine whether the allocation factors proposed in this proceeding remain reasonable.

NCSEA in its Initial Comments stated that DEP and DEC's proposed changes to the seasonal weighting of capacity rates are closely related to the issues that were presented relating to the modification of Option B in Phase One, noting that the Commission declined to adopt the proposed modifications to Option B at that time. NCSEA stated that to the extent the Commission is willing to consider modifications to the hours and seasonal weighting, it should be deferred until a future proceeding when changes can be evaluated in a comprehensive manner.

In its Reply Comments, NCSEA disagreed with the Public Staff's acceptance of the changed seasonal weightings. It noted that in both the Sub 136 proceeding and Phase One of this proceeding, parties proposed to adjust the hours offered under Option B, but the Commission ultimately concluded that DEC, DEP, and DNCP should continue to calculate and include in their avoided cost rate schedules an Option B, with the avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the Settlement Agreement entered into among DEC, DEP, and the Public Staff in the 2012 biennial proceeding. NCSEA asserted that the Utilities' proposed seasonal weighting based on CT production data is inconsistent with the peaker method, and stated that, to the extent the Commission is willing to consider modifications to the definitions of on-peak and off-peak hours and allocation of capacity cost based on the Utilities' demand, consideration should be deferred until a future proceeding when changes can be evaluated in a comprehensive manner to better tailor rates to the Utilities' needs.

DEC and DEP in their Joint Reply Comments stated that the changes in their seasonal allocation factors were adopted to create a more standardized and uniform methodology to use in their calculation of avoided costs, and to send more consistent price signals across their North Carolina service territories. They stated, however, that individual analyses for DEC Option B and DEP Options A and B based on CT production support the use of the 60% summer and 40% non-summer allocation. As such, DEC and DEP recommended that the Commission find their proposed seasonal allocations to be appropriate and justified.

DISCUSSION AND CONCLUSIONS

With regard to NCSEA's argument that DEC's and DEP's adjustments to the seasonal allocation factor would not comport with the peaker method, the Commission disagrees. The theory underlying the peaker method, as recognized by the Commission in Phase One of this proceeding and in prior proceedings, is that the capacity cost of the peaker plus the marginal system running costs equals the cost of any generating plant, including a baseload plant. Once that initial determination of capacity cost is made, the calculation then leaves the framework of the peaker methodology and becomes a ratemaking question. The actual hours during which that capacity value is allocated may vary based on production data, seasonality, and other factors. The Commission finds that it is appropriate to base the number of hours over which capacity value is allocated on the peak hours when the utility typically operates its fleet of CTs. Second, it is reasonable that similar production costs for the on-peak and off-peak hours be grouped together, and thus the Commission has historically allowed the Utilities to allocate such costs on a seasonal and hourly basis.

For the current proceeding, the Commission finds that the Utilities' proposed seasonal allocations are reasonable, but that it is appropriate to continue to evaluate the seasonal allocation factors used by the Utilities for avoided costs in light of changing seasonal peak load conditions experienced in North Carolina. Therefore, the Commission directs the Utilities in the next biennial proceeding to assemble their hourly CT operational data and marginal cost data on a season-specific basis in order to determine whether the allocation factors utilized in this proceeding remain reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in Exhibit 4 to the Initial Statements of DEC and DEP, the Joint Reply Comments of DEC and DEP, the Reply Comments of NCSEA, and the Initial Statement of the Public Staff.

In their standard contracts filed with their Initial Statements (Exhibit 4), DEP and DEC included language in their PPAs requiring a QF larger than 100 kW to provide notice of annual, monthly, and day-ahead forecasted hourly production. In its Initial Statement, the Public Staff indicated that it had discussed the difficulty and ambiguity of this reporting requirement with DEC and DEP. Both utilities indicated that the requirement was intended to give system operations ample notice of QF operations to allow them to plan generation accordingly, particularly when a QF was experiencing an outage. The Public Staff stated that while it believed such reporting might be appropriate for certain facilities, the threshold for reporting and the detail required appeared onerous and did not provide clear direction to the QF when it was necessary to report such operations.

As a result of these the discussions, the Public Staff, DEC, and DEP agreed to the following language as a substitute for Paragraph 5 of DEC's and DEP's standard contracts:

> Upon request, facilities larger than 3,000 kW may be required to provide prior notice of annual, monthly, and day-ahead forecast of hourly production, as specified by the Company. If the Seller is required to notify the Company of planned or unplanned outages, notification should be made as soon as known. Seller shall include the start time, the time for return to service, the amount of unavailable capacity, and the reason for the outage.

In their Joint Reply Comments, DEC and DEP noted that the information that would be provided by this revised reporting requirement would aid them in procuring alternative resources when a QF plans reduced operations. Further, as a request for planned operational information is unlikely to be necessary for QFs below three MW, exempting QFs below that threshold is deemed to be reasonable based upon current system operations.

In its Reply Comments, NCSEA noted the value of accurate production data for system operations and the purpose of the proposed provision. However, NCSEA expressed concerns regarding the production forecast requirements agreed to by the Public Staff and DEC and DEP. It noted that accurate hourly production forecasts for QFs often require sophisticated meteorological analysis, the cost of which is prohibitive at this time for most small QFs. NCSEA contended that the Utilities have superior forecasting resources and capabilities to those of QFs, and thus the likelihood of reliance by a utility on production forecasts provided by a QF is very low. Therefore, NCSEA recommended that the Commission reject the DEC/DEP/Public Staff proposal as it relates to production forecasting, but that the issue of production forecasting be revisited in a future proceeding when forecasting tools available to QFs have improved and become more cost effective. NCSEA requested that if the Commission is inclined to include the language agreed to by the Public Staff, DEC, and DEP related to production forecasts, that the Commission consider revising the language to make clear that a QF may rely on the production forecasts produced during the design/development process to fulfill its obligations under the contract provision, and that any inaccuracy in the forecasts shall not give rise to a right to terminate by the respective utility.

DISCUSSION AND CONCLUSIONS

The Commission finds that the language agreed to by DEC, DEP, and the Public Staff should allow DEC and DEP to plan system operations without being unduly onerous to the QFs. While the Commission understands NCSEA's concerns regarding the production forecasting requirement, NCSEA's proposal that it be able to use the forecasts developed during its design and development may be sufficient to satisfy the requirement in some cases, and insufficient in others. Further, while the Commission is aware that the Utilities have developed sophisticated forecasting capabilities beyond what should be expected of a small QF, a certain degree of accuracy in a QF's forecast should be expected. Whether repeated inaccuracies rise to the level and degree to merit contract termination would be a subjective determination that would depend on the circumstances. Therefore, the Commission concludes that it is appropriate for DEC's and DEP's Standard Contracts to include the language agreed to by DEC, DEP, and the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is contained in Section 6 of DEC's and DEP's Terms and Conditions (Exhibit 5 to their Initial Statements), NCSEA's Initial Comments, the Reply Comments of the Public Staff, and the Joint Reply Comments of DEC and DEP.

Section 6 of DEC's and DEP's proposed Terms and Conditions states:

> Reduction in Contract Capacity or Energy - If Seller's average energy generated in the on-peak or off-peak periods or capacity during any 12-month period falls significantly below the Contract annual kilowatt-hours or Contract Capacity, the Company may petition the North Carolina Utilities Commission to invoke a Reduction-In-Contract-Energy-Charge or Reduction in Contract Capacity Charge and establish a new Contract Energy and Capacity level. If approved by the Commission, the Reduction-In-Contract-Energy-Charge shall be equal to the total Energy Credits received for all prior years of the current Contract Period, less an amount computed at the new Contract Energy level using the on-peak or off-peak energy credit contained in the Purchase Agreement, less an amount equal to the energy supplied in all prior years of the current Contract Period which is in excess of the new Contract Energy level priced at the Variable Rate for energy which was in effect at the time the energy was delivered as specified in Company's applicable purchased power rate schedule, plus interest. The reduction in Contract Capacity

> Charge shall be a quantity equal to the amount as calculated under the Early Contract Termination clause multiplied by the ratio of the capacity reduction to existing Contract Capacity, plus interest. The interest rate shall be the same interest rate as computed in accordance with the Early Contract Termination provision.

In its Initial comments, NCSEA noted that prior to the Standard Contract approved pursuant to the Sub 136 Order, DEP's Standard Contract had included a similar provision. NCSEA pointed out that in Sub 136, the Commission concluded:

> [T]he provisions in DEP's Terms and Conditions that allow DEP to charge QFs a Reduction-in-Contract-Capacity and a Reduction-in-Contract-Energy starting two years after a QF begins operations are inconsistent with previous rulings of the Commission. Further, such charges are inconsistent with DEP's stated purpose of ensuring that QFs do not decrease production in the later years of levelized QF contracts, as they may apply in both early (after two years) and later years of a contract. Accordingly, such provisions should be removed from the DEP's Terms and Conditions. In lieu thereof, DEP may propose a provision that allows it to take action if the harm it alleges the penalty is designed to fix occurs (i.e., lower production in the later years of a long-term levelized contract) and file it for Commission approval.

NCSEA also noted in that proceeding, the Commission invited DEP to propose an alternative provision to address the harm caused by lower production in the later years of a long-term levelized contract. NCSEA contended that DEC and DEP's current proposal, similar to the provision that was struck in Sub 136, is inconsistent with the purpose of ensuring that QFs do not decrease production in the later years of levelized QF contracts because it can apply in both early and later years of a contract. NCSEA opposes the proposal as being inconsistent with the 2012 Order, unnecessary, and unduly punitive. Additionally, NCSEA challenged the provision based on its being confusing. NCSEA stated that the provision "combines shortfalls in capacity and shortfalls in delivered energy into a single triggering condition" and does not define the phrase "significantly below." It also contended that the definition of the essential term "Contract Energy" is confusing as well, and that the basis for the calculated charge is obscure and does not bear any relation to the harm it is supposed to address. Thus, NCSEA recommended that the Commission reject DEC and DEP's proposal on the same basis that it rejected the provision in its 2012 Order.

In its Reply Comments, the Public Staff noted its initial comments in the Sub 136 proceeding that recognized the Commission's holding in Docket No. E-100, Sub 59, that a utility could require a QF to state the amount of capacity and energy it intends to provide, but the utility could not use the stated amount to penalize the QF, particularly a QF that cannot control its fuel, such as run-of-the-river hydro, solar, or wind, absent an explicit order from the Commission.[1] The Public Staff further stated that QFs, under the standard contracts, are not paid unless they are generating, and, therefore, a penalty is unwarranted. The Public Staff also pointed out that in Phase One of this proceeding, the Commission had received evidence on this issue and concluded that "experience has shown that there is limited risk of nonperformance." The Public Staff recognized that while there may be some risk that a QF could underperform in the later years of a long-term levelized contract after receiving the benefits of a levelized contract in the early years, DEC and

[1] Initial Statement of the Public Staff filed on February 7, 2013, in Docket No. E-100, Sub 136, at p. 30.

DEP's proposal does not address this concern. Thus, the Public Staff recommended that the Commission direct DEC and DEP to refile a proposal that more directly addresses underproduction in later years of a levelized contract, resulting in overpayment during the early years of the contract. The Public Staff also recommended that until such a proposal is approved by the Commission, DEC and DEP should remove the Reduction Contract Energy and Reduction in Contract Capacity charge provisions from their proposed Terms and Conditions. Finally, the Public Staff recommended that in the interim, DEC and DEP may apply to the Commission for approval to impose a charge on a case-by-case basis, at which time the Commission can determine the extent, if any, of the harm that the charge would address.

In their Joint Reply Comments, DEC and DEP maintained that their proposed Reduction in Contract Energy Charge and Reduction in Contract Capacity Charge are reasonable and should be retained. They noted that their filings in Docket No. E-100, Sub 136, contained similar, but not identical, language intended to protect their customers. DEC and DEP noted that long-term levelized rate QF contracts both encourage QF development and run the risk of producing overpayments to QFs. They contended that these rates tend to overpay the QF in the early years and underpay in later years. Thus, a QF's economic incentive to incur the costs of operating and maintaining its facility diminishes over the life of a long-term levelized contract. Therefore, DEC and DEP contended that they and their customers should not have to risk underperformance at the end of a contract with a QF having benefitted by the levelized rates in the early years. DEC and DEP stated that they believe their proposal provides a mechanism to address the situation should the QF's performance falls short of its contractual obligation. They contended that the provision proposed in this proceeding is more narrowly tailored to the harm it is intended to prevent than that proposed in previous proceedings. Further, they argue that their provision is not punitive because they cannot impose a charge without Commission approval.

DISCUSSION AND CONCLUSIONS

The Commission has recognized the potential for levelized contracts to create the risk of underproduction in later years of a contract. Certainly, performance and maintenance issues as reported by Advanced Energy, if they go unaddressed, would increase the likelihood of this risk. However, the Commission found in Phase One that the potential for underperformance is minimal and that QFs' financing offers contain incentives for them to perform fully through the term of the contract. The language proposed by DEC and DEP would unnecessarily apply throughout the term of the contract, when the purpose is to address events only in the later years of the contract. Thus, again, the proposed language is overly broad. Further, the proposed language still requires adjudication by the Commission to determine whether a charge should be imposed, and if so, in what amount. The Commission has previously ruled that the Utilities have the right to apply to the Commission for imposition of a charge. Thus, the proposed language regarding adjudication only serves to note the existence of an action already permitted by the Commission, i.e., for DEC and DEP to file a complaint for Commission adjudication.

The Commission believes the approach recommended by the Public Staff has merit and therefore finds that DEC and DEP should remove the Reduction Contract Energy and Reduction in Contract Capacity Charge provisions from their proposed Terms and Conditions unless and until the Commission approves revised language that more directly addresses underproduction in later years of a levelized contract that results in overpayment during the early years of the contract.

Further, as is already permitted, the Utilities may apply to the Commission for approval to impose a charge on a case-by-case basis.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in Exhibit 4 to the Initial Statements of DEC and DEP; the Initial Comments of NCSEA; the Reply Comments of the Public Staff and DNCP; and the Joint Reply Comments of DEC and DEP.

In its Initial Comments, NCSEA noted that DNCP's Terms and Conditions provide that a QF may assign its rights under DNCP's Standard Contract only with the prior written consent of DNCP, and that DNCP "may withhold such consent if it determines, in its sole discretion, that such assignment would not be in the best interests of DNCP or its customers." NCSEA contended that granting DNCP sole discretion to reject an assignment for any reason is commercially unreasonable, and proposed that DNCP amend this provision to require that it not unreasonably withhold consent to proposed assignment. Similarly, NCSEA pointed out that the assignment provisions in DEC's and DEP's Standard Contracts give them "undue discretion to disapprove or put onerous conditions on the assignment rights, such as the requirement of financial security, which … have the potential to serve as an impediment to QF development." NCSEA recommended that the Commission direct DEC and DEP to revise their assignment provisions to require that they not unreasonably withhold consent to a proposed assignment, and not require commercially unreasonable measures, such as security.

In its Reply Comments, the Public Staff noted that in order to encourage QF development in compliance with PURPA, the Commission has, since Docket No. E-100, Sub 41A, included standard rates, terms, and conditions in its biennial avoided cost proceedings to reduce the transaction costs for smaller project developers who may not have the resources or expertise to negotiate with a utility. The Public Staff stated that the Utilities' proposed assignment provisions could constitute an unreasonable burden on QF development and recommended that the provisions be revised.

In their Joint Reply Comments, DEC and DEP contended that their standard contracts protect customers by providing that PPAs can only be assigned to a third party if the assignee is able to assume the QF's outstanding financial responsibilities. Thus, DEC's and DEP's proposed Standard Contracts provide that the PPA may be assigned to a third party if DEC or DEP is reasonably satisfied that the assignee will fulfill the financial obligations of the QF. DEC and DEP noted that this provision is similar to a provision currently in DEP's Terms and Conditions on file in Sub 136, except that they have added a sentence in reference to the regulatory approvals required by the Commission. DEC and DEP contended that this provision is intended to protect them, and ultimately, the ratepayers from assignment of a PPA to a QF that is unable to pay. DEC and DEP stated that a review of their records indicates that the only assignments they have declined were those that would have required that they accept a bank as a second counterparty.

In its Reply Comments, DNCP stated its agreement to revise Section I of the Schedule 19-FP and Schedule 19-LMP Terms and Conditions to state that it will not unreasonably withhold its consent to assignment of the PPA, provided that the assignment does not require any amendment of the Terms and Conditions of the PPA other than the notice provisions.

The Commission concludes that the Utilities should not unreasonably withhold consent to a proposed assignment of a standard PPA. This holding is consistent with prior Commission precedent keeping QFs' transaction costs to the minimum necessary, while allowing the Utilities to ensure that an assignee has the financial means to assume the obligations of the assignor. The Commission finds that the language DNCP has agreed to include in its Schedules is appropriate, and directs DEC and DEP to include similar language stating that they cannot unreasonably withhold consent to assignment in their standard contracts

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is contained in the Initial Statement and Exhibits of DNCP, the Initial Comments of NCSEA, the Reply Comments of the Public Staff, and the Reply Comments of DNCP.

In its proposed Standard Contract, DNCP included a provision in Article 7(a)(vii) that grants the utility a right to terminate the contract when the FERC grants a petition by the utility under PURPA Section 210(m), relieving the utility of its purchase obligation.

In its Initial Comments, NCSEA disagreed with DNCP's characterization of a grant by the FERC of a PURPA Section 210(m) application as constituting default by a QF, and stated that, to the extent the provision is permissible, it should not be included in Article 7(a), which is titled "Defaults with No Cure Period." NCSEA also noted that DEC's and DEP's proposed Terms and Conditions give the Utilities broad discretion to suspend or terminate contracts without an opportunity to cure. However, the current Terms and Conditions for both DEC and DEP require them to give advance notice to the QF of termination, except in circumstances where there is a dangerous condition or if the QF has engaged in fraudulent or unauthorized use of the utility's meter.

In its Reply Comments, the Public Staff noted that at the time of the filing of its Initial Statement, DNCP had a PURPA Section 210(m) application pending before the FERC,[1] but subsequently the FERC declined to grant that petition.[2] As no petitions were pending, the Public Staff found inclusion of this provision to be unnecessary and recommended that the Commission direct DNCP to remove the provision. If the Commission allowed this provision to remain, the Public Staff recommended that it be moved from the default section of the Standard Contract to a stand-alone clause.

In its Reply Comments, DNCP proposed to move the PURPA Section 210(m) provision from the default section in the 19-FP and 19-LMP PPAs to the end of Article 2 (Term and Commercial Operations Date) in those agreements.

The Commission concludes that DNCP's PURPA Section 210(m) provision is unnecessary. While it is clear that the provision should not be included in the section of DNCP's Standard

[1] Virginia Electric and Power Company, Application to Terminate Purchase Obligation, Docket No. QM15-1-000 (Oct. 31, 2014).

[2] Virginia Electric and Power Co., Order Denying Application to Terminate Mandatory Purchase Obligation. Docket No. QM15-1-000, (April 16, 2015); 151 FERC ¶61,038 (2015).

Contract dealing with default, attempting to address any potential governmental actions that might affect the PPA, including the grant of a PURPA Section 210(m) petition, is unnecessary in a Standard Contract. If Commission intervention is necessary, the Commission will deal with such situations as they arise. As such, DNCP should remove this language from its Standard Contract.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is contained in Exhibit 4 to the Initial Statements of DEC and DEP, the Initial Comments of NCSEA, the Reply Comments of the Public Staff, and the Joint Reply Comments of DEC and DEP.

DEP's Terms and Conditions approved by the Commission in the Sub 136 proceeding included the following statement:

> Company shall give Seller a minimum of 30 calendar days prior written notice before terminating or suspending the Agreement pursuant to provisions 1(h)(l)(default or breach of Agreement by Seller), 1(h)(3)(failure to pay any applicable bill when due and payable) or 1(h)(5)(Seller's inability to deliver to Company the quality and/or quantity of electricity mutually agreed to in the Purchase Agreement), above: however, termination or suspension pursuant to provisions 1(h)(3)(fraudulent or unauthorized use of Company's meter) or 1(h)(4)(presence of dangerous condition) shall be immediate.[1]

In its Initial Comments, NCSEA noted that while DEC's and DEP's Standard Contracts provides a QF advance notice of termination (except where there is a dangerous condition or if the QF has engaged in fraudulent or unauthorized use of the utility's meter), it does not give a QF the opportunity to cure the condition giving rise to termination. NCSEA pointed out that DNCP provides a 30-day cure period for most defaults. NCSEA contended that many circumstances of default are temporary or curable, and that it would be commercially unreasonable if a cure provision were not included. NCSEA recommended that Section 1(i) of DEC's and DEP's Terms and Conditions be modified to provide the QF notice and a reasonable opportunity to cure prior to authorizing termination by the utility.

In its Reply Comments, the Public Staff noted that it generally supports the inclusion of commercially reasonable opportunities to cure in QF PPAs in order to avoid impermissible burdens on QFs in violation of PURPA, and recommended that DEC and DEP amend their Terms and Conditions to provide QFs a reasonable opportunity to cure prior to termination of the contract. The Public Staff also recommended that DEC and DEP provide clearer guidance regarding the circumstances in which termination or suspension is warranted.

In their Joint Reply Comments, DEC and DEP agreed with NCSEA that QFs should be allowed an opportunity to cure before termination (except in dangerous conditions and in cases of fraud). While they acknowledged the 30-day period included in Sub 136 by DEP, they now argue that 30 days is in excess of what is required to cure, as the QF should already be aware of the situation

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[1] DEP, Terms And Conditions For The Purchase Of Electric Power, Sheet 2 of 9, Filed in Docket No. E-100, Sub 136, Effective April 1, 2014.

except for dangerous conditions. They also pointed out that the new Interconnection Agreement approved by the Commission in Docket No. E-100, Sub 101 provides a five-day cure period, and proposed the same period for their Standard Contracts to be consistent and lessen confusion.

In their letter of September 17, 2015, indicating settlement of several issues with NCSEA, DEC and DEP noted that they had agreed that for termination issues that are included in both the interconnection agreements and the PPA, there will be a five-day cure period in Section (i) of its Terms and Conditions. For termination issues that are not covered by the interconnection agreement, the Terms and Conditions will contain a 30-day cure period, except for fraudulent or unauthorized use of Company's meter where termination is immediate. DEC and DEP provided language that they and NCSEA have agreed was appropriate.

The Commission concludes that QFs should have a commercially reasonable opportunity to cure prior to termination of a contract. The language proposed by DEC and DEP in their September 17, 2015 letter provides a reasonable opportunity to cure and should be included in DEC's and DEP's Terms and Conditions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is contained in the Initial Statements of DEC, DEP, and DNCP, the Initial Comments of NCSEA and SACE, and the Reply Comments of DEC, DEP, DNCP, NCSEA, and the Public Staff.

In DNCP's Schedule 19, Section I filed with its Initial Statement, DNCP proposed that standard rates not be available to a QF owned by a developer or affiliate who sells or will sell power to DNCP from another QF located within one mile unless the combined capacity is equal to or less than five MW. DEC and DEP proposed a similar restriction in their Initial Statements, but proposed a one-half mile limitation, as opposed to the one mile proposed by DNCP.

In its Initial Comments, NCSEA pointed out that DEC included a similar provision in the past with a one-half mile limitation and included the same provision in this proceeding. DEP also proposes to include the same provision in this proceeding. NCSEA pointed out that DNCP provided no justification for increasing the limitation to one mile. NCSEA recommended that the Commission approve DEC and DEP's one-half mile proposal and limit DNCP to one-half mile, while maintaining the qualification that two QFs under the same or affiliated ownership are eligible for the standard offer so long as the combined capacity of those facilities does not exceed five MW.

In its Initial Comments, SACE pointed out that under PURPA, a facility is eligible for certification as a QF based on three criteria: the distance between the facilities (measured between the respective facilities' electric-generating equipment), ownership, and the type of energy resource. SACE noted that the requirement that two facilities be located more than one mile apart only applies to facilities under common ownership that use the same type of energy resource. SACE concluded that the one-mile radius restriction and the five MW restriction in DNCP's Schedule 19 should only apply when two proposed facilities under common ownership use the same energy resource. SACE further recommended that the distance between facilities should be measured from the electrical-generating equipment of a facility for purposes of making the one-mile determination.

In their Joint Reply Comments, DEC and DEP noted that their provisions in question are long established and consistent with the five MW threshold set by the Commission in 1997 in Docket No. E-100, Sub 41A. They explained that the intent of this provision was to ensure that larger QF developers could not avoid negotiating with the utility by breaking up larger facilities into multiple, closely-located five MW or less facilities. DEC and DEP argue that SACE's citation of the PURPA rules misses the point and pertains to the FERC requirements for certification of a facility as a QF under the "one mile rule", not to the availability of standardized rates, terms, and conditions to QFs. They maintain that their Terms and Conditions are entirely consistent with the FERC's one mile rule, as a Standard Contract is available to facilities that are certified as QFs as defined by the FERC in 18 C.F.R. §§ 292.203, 292.204, and 292.205. DEC and DEP state that the issue is not whether a facility meets the FERC criteria to be certified as a QF, but whether QFs owned by the same seller or an affiliate that sells power to the utility from another QF within one-half mile are eligible for the Standard Contract. DEC and DEP point out that like the five MW eligibility threshold, the limitation on eligibility for facilities owned by the same seller or an affiliate is a Commission determination, not a FERC determination. Finally, they note that neither the Public Staff nor NCSEA objected to this provision, and that SACE has not presented a compelling reason for the Commission to depart from its prior determination.

In its Reply Comments, DNCP agreed with SACE's comments that the one-mile rule and the five MW restriction in Schedule 19 should only apply when the two proposed facilities are under common ownership and use the same energy resource. DNCP also agreed with SACE that for purposes of the one-mile rule, the distance between facilities is measured from the electrical-generating equipment of each facility. DNCP modified its proposed Schedule 19-FP and Schedule 19-LMP accordingly.

However, DNCP did not agree with NCSEA's recommendation that the Commission reduce the geographical limitation for renewable resource QFs to one-half mile. DNCP pointed out that its proximity limitation had long been contained in Schedule 19, and ensures that Schedule 19 is available only to small QFs with a net capacity not greater than five MW. DNCP noted that the geographic siting limitation for the purpose of determining the size of renewable resource QFs under Schedule 19 is the same one-mile test used by the FERC in 18 C.F.R. § 292.204(a) to determine the size of a small power production QF such as a solar QF.

In its Reply Comments, the Public Staff noted that DNCP has previously limited eligibility for its Schedule 19 tariffs to QFs owned by a seller or affiliate within one-half mile, but proposes increasing the limitation to one mile. The Public Staff also pointed out that DEC has historically included a similar one-half mile availability limitation, and that DEP has proposed to include the same limitation. The Public Staff recommended that the Commission adopt a consistent availability limitation for all three Utilities of one-half mile, while maintaining the qualification that two or more QFs under the same or affiliated ownership are eligible for the standard offer rates and terms so long as the combined capacity of those facilities does not exceed five MW. The Public Staff also agreed with SACE that the one-half mile restriction should only apply to facilities that use the same energy resource, and recommended that the Utilities include language stating that the distance between facilities would be measured from the electrical-generating equipment of a facility.

The Commission concludes that in the interests of consistency and clarity, it is appropriate for each utility to limit the availability of standard rates to facilities within one-half mile, provided two or more QFs under the same or affiliated ownership are eligible for the standard offer rates and terms if the combined capacity of those facilities does not exceed five MW. DNCP has not provided adequate justification for increasing the one-half mile limitation to one mile. Further, there does not appear to be disagreement with SACE's proposal that the one-half mile restriction only to facilities that use the same energy resource, or the requirement to include language stating that the distance between facilities should be measured from the electrical-generating equipment of a facility. Therefore, the Commission finds it appropriate for the Utilities to include this language in their standard rates.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19 – 20

The evidence supporting these findings of fact is contained in the Initial Statements of DEC, DEP, and DNCP; the Initial Comments of NCSEA; and the Reply Comments of DEC, DEP, and the Public Staff.

In its Initial Comments, NCSEA pointed out that in the 2012 Order, the Commission approved a 30-month deadline for achieving commercial operation and provided that the deadline could be extended if the project is progressing and the QF is making a good faith effort to complete the project. NCSEA noted that DNCP had included the deadline extension language in its proposed contract, but DEC and DEP had not. Additionally, NCSEA sought to clarify that the contract term commenced on the date the QF first delivers electricity rather than on the contract date. NCSEA recommended that DEC and DEP include the deadline extension language in their contracts as had been ordered by the Commission in 2012 and clarify that the term commenced upon delivery of electricity.

In its Reply Comments, the Public Staff addressed NCSEA's concern regarding extension of the 30-month deadline and recommended that the Commission direct DEC and DEP to amend their consent provisions to provide that consent to an extension of this initial delivery date shall not be withheld if the project is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner.

In their Joint Reply Comments, DEC and DEP indicated that they had reached agreement with NCSEA to clarify in both Schedule PP and the Purchased Power Contract to indicate that the 30-month deadline can be extended. Further, DEC and DEP indicated that they and NCSEA had reached agreement that the term shall begin upon the first date when energy is generated by the QF and delivered to the utility.

In DEC and DEP's September 17, 2015 letter to Commission advising of their settlement of several issues with NCSEA, DEC and DEP provided language they and NCSEA had agreed upon allowing extension of the 30-month deadline if construction is nearly complete and the QF shows that it is making a good faith effort to complete its project. DEC, DEP, and NCSEA also agreed that the provision allowing termination if the QF does not deliver the quality or quantity of electricity provided in the PPA would not cover a situation where the QF was unable to deliver due to circumstances beyond its control, such as weather conditions, but rather situations within the QF's control such as unrepaired equipment.

It appears that NCSEA, DEC, and DEP have reached agreement that the 30-month deadline may be extended if the project is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner. They have also agreed to clarify that the term begins upon delivery of electricity. The Commission concludes that the language agreed to by these parties is appropriate and should be included in DEC's and DEP's Standard Contracts.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence supporting this finding of fact is contained in Exhibit 6 to the Initial Statements of DEC and DEP; the Initial Comments of NCSEA; and the Reply Comments of DEC, DEP, and the Public Staff.

Section 1(i) of DEC's and DEP's respective proposed Terms and Conditions provides the right to terminate a contract "due to the Seller's inability to deliver to the Company the quality and/or quantity of electricity mutually agreed to in the Purchase Agreement." NCSEA objected to this provision on several bases: (1) it does not clearly define the standard for quantity or quality; (2) it does not indicate what degree of deviation from the standard would be grounds for termination; (3) the utility has absolute discretion to terminate; (4) termination is an excessive remedy for under-delivery of energy or capacity; (5) the provision is duplicative of the "reduction-in-contract-energy" and "reduction-in-contract-capacity" charges discussed above; and (6) the provision is inconsistent with prior orders of the Commission. Thus, NCSEA recommended that the Commission direct DEC and DEP to remove this provision.

In its Reply Comments, the Public Staff again pointed out the Commission's holding in Docket No. E-100, Sub 59, that allowed a utility to require a QF to state the amount of capacity and energy it intended to provide, but also held that the utility could not use this statement to penalize the QF, without an explicit order from the Commission. The Public Staff concluded that since QFs under standard contracts are not paid unless they generate, the provision is unnecessary.

In their Joint Reply Comments, DEC and DEP indicated that they had discussed this matter with NCSEA and had agreed to add to Section 1(i) the following language: "Termination of the contract is at the Company's sole option and is only appropriate when the Seller either cannot or will not cure its default or if the Seller fails to deliver energy to the Company for more than six months."

The Commission concludes that the addition of this language to Section 1(i) of the Terms and Conditions for DEC and DEP addresses the concerns of DEC, DEP, NCSEA, and the Public Staff in that it provides DEC and DEP a remedy for non-performance and is clear as to the standard for such right to terminate to arise. Therefore, DEC and DEP are directed to include this language in section 1(i) of their Terms and Conditions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding of fact is contained in Exhibit 6 to the Initial Statements of DEC and DEP; the Initial Comments of NCSEA; and the Reply Comments of DEC, DEP, and the Public Staff.

In its Initial Comments, NCSEA noted that DEC and DEP have included various provisions in their standard offers related to the interconnection of QFs. NCSEA contended that some of these references to interconnection are unclear, have the potential to mislead, and are contradictory. It provided as examples Section 4 of DEC and DEP's respective Standard Contracts, Section 13 of their respective Terms and Conditions, and DEP's Rate Schedule. NCSEA recommended that the Commission require DEC and DEP to strike all provisions in the power sales documents related to interconnection, include a simple reference to the North Carolina Interconnection Procedures, Forms, and Agreements, and state that an interconnection agreement is necessary in order to deliver output to the utility.

The Public Staff agreed with NCSEA that these provisions related to interconnection should not be included since the Commission has adopted separate procedures, forms, and agreements in Docket No. E-100, Sub 101, related to the interconnection of QFs, and inclusion could cause confusion and result in inconsistencies.

In their Reply Comments, DEC and DEP indicated that they had reached agreement with NCSEA on this issue. DEC, DEP, and NCSEA have agreed that inclusion of the terms regarding interconnection is intended to enhance clarity and transparency, and that if there is any conflict between interconnection terms, the interconnection agreement will control. In their letter of September 17, 2015, noting settlement of certain issues with NCSEA, DEC and DEP included specific language providing that the interconnection agreement controls if in conflict with the Terms and Conditions.

DISCUSSION AND CONCLUSIONS

The Commission concludes that the interconnection agreement should control in the event that there is conflict between the terms of the standard contract and an interconnection agreement. Therefore, the provisions related to interconnection in DEC's and DEP's standard offers may remain, subject to the condition that the interconnection agreement controls if there is a conflict. The Commission finds the language agreed to by DEC, DEP, and NCSEA is appropriate and should be included in the Terms and Conditions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence supporting this finding of fact is contained in Exhibit 6 to the Initial Statements of DEC and DEP; the Initial Comments of NCSEA; and the Reply Comments of DEC, DEP, and the Public Staff.

DEC's Rate Schedule includes the following provision:

> POWER FACTOR CORRECTION
>
> Unless the Seller is required by an Operating Agreement to adjust VAR production to support voltage control, when the Seller consumes VARs supplied by the Company or the Seller delivers VARs to Company, the Company may reduce the purchased energy measured in kilowatt-hours for that month by multiplying by the Average Consumed Power Factor. The Average Consumed Power Factor shall be the calculated on a monthly basis as the average kWh divided the average kVAh,

where average kVAh shall be the square root of the sum of the average kWh squared plus the average consumed and delivered kVARh squared. Company reserves the right to install facilities necessary for the measurement of power factor and to adjust the Interconnection Facilities Charge accordingly, solely at the option of Company.

Similarly, DEP proposed to bill a QF at a rate of $0.34 multiplied by the number of kVARs consumed or supplied by the QF and stated that a QF may enter into an "Operating Agreement" with the utility to adjust VAR production to support voltage control.

In its Initial Comments, NCSEA noted that DEC's provision would allow the utility to reduce the power factor without crediting a QF when it produces reactive power that benefits the utility. NCSEA contends that DEC's and DEP's provisions are unclear and, in effect, penalize QFs by not allowing them to benefit when they provide the Utilities reactive power. It requested that the Commission scrutinize these provisions.

The Public Staff noted that Section 1.8 of the Interconnection Agreement approved by the Commission in Docket No. E-100, Sub 111 provides that an interconnection customer, with the exception of wind generators, must operate within a power factor range of 0.95 leading to 0.95 lagging at continuous rated power output, and that a utility must pay the interconnection customer when the utility requests the customer to operate outside of that range. The Interconnection Agreement also requires a utility to pay an interconnection customer for reactive power to the extent it pays its own or affiliated generator. The Public Staff recommended that the Commission require DEC and DEP to update their rate schedules to reflect their obligation to pay for reactive power that the interconnection customer provides or absorbs at the Utilities' request.

In their Joint Reply Comments, DEC and DEP stated that they had revised the power factor provisions to clarify that a QF should operate its generation so that it will not adversely impact voltage. QFs without specific operating agreements are requested to operate at a unity or 100% power factor without either supplying or consuming VARs. DEC and DEP contend that this approach should prevent potential conflicts with normal system operations that could adversely impact service. DEC and DEP note that an operating agreement may be appropriate for larger QFs that can actively provide direct voltage support, and the agreement would specify the ancillary service requirements and compensation for the service. In regard to smaller QFs without an operating agreement, DEC and DEP indicate that as they must install capacitors if a smaller QF is not operating during a low voltage event, no costs are avoided. DEC and DEP propose to charge QFs not operating at a unity power factor for VAR consumption or supply similarly to their retail customers. DEC and DEP dispute NCSEA's assumption that the provision of VARs benefits the utility, arguing that this reactive power conflicts with their normal operations and may increase the cost of maintaining voltage in the area. They note that a unity power factor should also be desirable from the QF's perspective.

The Commission concludes that as to the issue of reactive power provided or absorbed at the utility's request, it appears that for larger generators with operating agreements, DEC's and DEP's operating agreements would specify the ancillary services and the compensation for such services. To the extent that a smaller generator provides or absorbs reactive power at the utility's request, it is also appropriate for DEC and DEP to pay for such power to the extent they pay their own or affiliated generator. DEC and DEP should, therefore, revise their rate schedules accordingly.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24 – 25

The evidence supporting these findings of fact is contained in the Initial Statements of DEC and DEP, the Initial Statement of DNCP and Exhibit A to Schedules 19-FP and 19-LMP, the Initial Statement of the Public Staff, the Initial Comments of NCSEA, the Joint Reply Comments of DEC and DEP, and the Reply Comments of DNCP.

In Phase One of this proceeding, DNCP witness Roger T. Williams explained that the Commission held in Sub 136 that an LEO is established when a QF has (1) obtained a CPCN (or filed a Report of Proposed Construction (ROPC), if applicable) and (2) indicated to the utility that it seeks to commit itself to sell its output to that utility. He further testified that DNCP believes that the standard is still too vague to be implemented in a fair manner, particularly with regard to the second prong of the LEO test, as there is not enough guidance regarding what it means for a QF to "commit itself to sell its output." DNCP proposed that the Commission adopt a form through which QFs could clearly show their intent to sell their output to a utility, thereby setting the date that a LEO is established (assuming that the first prong of the test has been met).

In its Order on Inputs, the Commission indicated that it was positively inclined towards this proposal. The Commission requested that parties address DNCP's proposal in more detail in Phase Two and listed certain questions that should be addressed:

> How the QF would know it needed to obtain the form, how it would obtain the form (e.g., from a specified place on a utility's website), whether or how the form could be submitted electronically, and the extent to which the utility could change or withdraw the form without prior Commission approval.

In their Initial Statements, DEC and DEP supported DNCP's proposal that a QF complete a simple form stating that it offers to sell its output, thereby setting the date of the LEO, to increase clarity and to "prevent 'gaming' of the LEO date." If a QF has obtained a CPCN or filed an ROPC, DEC and DEP indicated that an LEO form should require the QF to provide the date and docket number in which it received a CPCN or filed an ROPC with the Commission. If the QF has not received a CPCN but has filed an application the form should indicate the date of filing of the CPCN application. Finally, if neither an ROPC nor an application for a CPCN has yet to be filed the form should be supplemented upon filing. DEC and DEP stated that the form should be signed and dated by a person authorized to make a commitment. They indicated that they would make the form available on their websites, and would not object to QFs submitting the forms electronically. Finally, DEC and DEP noted that after initial Commission approval of a form, no further approval would be necessary unless the utility makes material changes to the form or ceases to use it. DEC and DEP did not propose a particular form for approval by the Commission.

In its Initial Statement, DNCP included comments responsive to the Commission's conclusions and questions and included a proposed LEO form as Exhibit A to Schedules 19-FP and 19-LMP (LEO Form). DNCP indicated that the proposed LEO Form should be used to determine the date of a QF's commitment to sell its output to the Company. DNCP's LEO Form contains: a formal request by the QF that DNCP enter into a PPA and purchase its electricity; contact information; certifications that it has received or applied for a CPCN or has filed or will file an ROPC with copies attached, the QF's intended rate schedule, termination provisions; and a survival clause. DNCP also included a section specifying how the LEO date will be determined for each QF. It stated that its LEO Form would be available on its web site as an exhibit to its applicable rate schedules. DNCP also indicated that upon completion of the form and submission by certified mail, courier, hand delivery, or e-mail to its Power Contracts Department, an LEO would be established and that any changes would be made only with Commission approval. Finally, DNCP proposed that use of the form to establish the second prong of the LEO test be mandatory.

In its Initial Comments, NCSEA submitted a proposed LEO form that it contended was much less complicated than the form submitted by DNCP, but contained the information necessary to establish a commitment to sell to the utility. NCSEA also recommended that the Commission make use of the form permissive instead of mandatory, allowing a QF to show it has committed to sell through other actions. However, NCSEA proposed that use of the form be encouraged on a prospective basis by creation of twin rebuttable presumptions regarding use of the form. NCSEA also advocated that the Commission make the establishment of the notice of commitment effective upon submission rather than upon receipt by the utility.

In its Initial Statement, the Public Staff indicated that it supported the creation of a simple form by which QFs and the Utilities could clearly establish the date of a LEO. The Public Staff stated that such a form could help clarify the rights and obligations of each party and avoid disputes that may ultimately have to be brought to the Commission for adjudication or to the Public Staff for informal resolution. The Public Staff recommended that the form be publicly available on each utility's website in sections dealing with interconnection agreements and PPAs, and that the Utilities should make clear to developers on their websites how to establish a LEO and which departments must be contacted to negotiate interconnection agreements and PPAs. Further, the Public Staff proposed that each utility, when confirming receipt of an interconnection request, include a statement as follows:

> The submission of an interconnection request does not constitute an indication of a customer's commitment to sell the output of a facility to the utility. For information on submitting a legally enforceable obligation (LEO) form or requesting a power purchase agreement (PPA), please see the following website: (provide relevant website link).

The Public Staff agreed with DEC and DEP as to the items they indicated should be included on the form. It also reviewed the form submitted by DNCP and agreed that the form should include: (1) the date and docket number of the QF's CPCN, or ROPC, or an update if the CPCN is granted or the ROPC is filed thereafter; (2) the signature and title of an authorized representative for the QF; (3) the QF's contact information; (4) instructions on how the form should be submitted; (5) date of submission; and (6) provisions regarding the termination of the LEO.

In their Joint Reply Comments, DEC and DEP indicated that they agreed with the Initial Statement of the Public Staff regarding development of a LEO Form. In its Reply Comments, DNCP submitted a revised form entitled a "Notice of Commitment" that incorporated a number of the changes recommended by NCSEA and the Public Staff in their initial filings (Revised LEO Form). DNCP agreed to remove the form from its schedules and make it available on its website on the sections dealing with Interconnection Agreements and PPAs, as well as include the language recommended by the Public Staff on its website and in its confirmation of receipt of an interconnection request. In response to NCSEA's and the Public Staff's comments, DNCP agreed to change the title of the form to "Notice of Commitment" and to remove the requirement to provide documentation of the CPCN or ROPC and instead just require the docket number. DNCP also added a place for the QF to indicate the size of its facility. It removed the requirement that a QF list the names and locations of any QFs owned or under development by the developer or its affiliates within one mile of the facility. DNCP also made the form effective upon submission, as recommended by NCSEA. DNCP agreed to remove language acknowledging that a QF cannot enter into a PPA without a CPCN or filing an ROPC as acknowledgement of current Commission policy, on the grounds that it is not necessary for purposes of the LEO Form. DNCP also modified section 5(b) to reflect both FERC requirements and Commission policy. DNCP agreed to revise its termination section, including a definition of "executable PPA," clarifying the potential extension of time allowed to execute a PPA in relation to the tender of an interconnection agreement, and providing that the Commission will set the deadline for execution of a PPA that is the subject of complaint or arbitration proceedings. DNCP also removed the survival clause previously contained at Section 7 of the proposed LEO Form. Finally, the LEO Form was revised to indicate that the person signing is duly authorized to execute the form.

DNCP did not alter its position that use of the form should be mandatory. DNCP pointed out that the point of developing the form was to make the process of satisfying the second prong of the LEO test as clear and simple as possible, and that allowing use to be permissive would lead to further disputes as to the date a LEO was established. DNCP also did not agree with NCSEA's recommendation that its proposed acknowledgements or representations by the QF should be removed. In regard to NCSEA's proposed form, DNCP contended that it does not contain all the information needed in order to determine when a LEO is established or when a LEO is terminated. DNCP argued that NCSEA's form would lead to further disputes instead of clarifying the establishment of a LEO.

In its Reply Comments, the Public Staff stated that it had reviewed DNCP's revised form, and determined that it resolved the specific issues raised by the Public Staff's Initial Statement regarding DNCP's form. The Public Staff also noted that DNCP's revised form was much simpler and recommended that the Commission make its use mandatory, as long as QFs are allowed a reasonable opportunity to cure any errors.

In regard to DNCP's revised form, NCSEA stated in its Reply Comments that it supported the form with one exception, the section regarding termination or expiration of the commitment. NCSEA noted that neither the FERC nor the Commission has issued clear guidance on the issue of when a commitment to sell or an LEO terminates or is no longer valid, and so contended that the provision was premature. NCSEA also reiterated that use of the form should be permissive.

After the submission of Reply Comments, the Public Staff filed a letter indicating that DEC, DEP, DNCP, NCSEA, and the Public Staff had engaged in further discussions and had agreed on the contents of Sections 1 through 4 of DNCP's revised LEO Form, customized as appropriate for use by DEC and DEP. However, the Public Staff noted that these parties had not reached consensus on Sections 5 and 6 of DNCP's revised LEO Form, which involve certain acknowledgements by the QF and termination of the commitment to sell.

On September 17, 2015, DEC and DEP submitted a proposed LEO Form for use by DEC and DEP and a further revised LEO Form on behalf of DNCP.

DISCUSSION AND CONCLUSIONS

The Commission concludes that use of a simple form clearly establishing a QF's commitment to sell its electric output to a utility to establish the notice of commitment to sell prong for creation of an LEO would provide clarity both to QFs and the Utilities and would, therefore, reduce the number of disputes between the parties and the number of complaints brought before the Commission for adjudication as to when an LEO was established. The revised form submitted by DNCP with its Reply Comments contains the information necessary to satisfy the second prong of the LEO test and should not be unduly burdensome for a QF to complete. As such, the Commission finds that use of the form should be mandatory.

In regard to the fifth section of DNCP's revised form, the Commission finds that while the acknowledgements contained therein are not necessary for establishment of a commitment to sell, they provide a QF notice of how the date of an LEO will be established, which should serve to reduce the potential for disagreements between QFs and DNCP. The provisions in Section 6 regarding termination of the Notice of Commitment are reasonable and similarly should serve to reduce the number of disputes. Once a QF and a utility enter into a PPA, the Notice of Commitment should terminate, as the purpose of a LEO, i.e., to ensure a utility enters into a PPA, will have been achieved. Further, the provision that the Notice of Commitment will be effective for up to 30 days after delivery of an "executable" PPA is reasonable. Likewise, the provisions in Section 6.c. for termination of the notice if the QF and utility are negotiating a PPA appear reasonable, as they allow extension by mutual agreement after six months; extension until five days after execution of an interconnection agreement, if it has not been executed; and tolling of the six month deadline if an arbitration or complaint is filed.

In its September 22, 2015 Order Establishing Date of Legally Enforceable Obligation in Docket No. E-22, Sub 521, the Commission determined that the developer in that proceeding was "not required to have obtained QF status in order to satisfy the Commission's two-prong LEO test." The Commission has not previously required a developer to have obtained QF status in order to establish an LEO, however, given the increasing number of disputes over the date of an LEO and the new required use of the LEO Form, to provide a standardized and clearly stated method to establish an LEO the Commission finds good cause to require prospectively that a developer obtain

QF status. Beginning concurrently with the mandatory use of the LEO Form (40 days from the issuance of this Order), a developer will be required to: (1) have self-certified with the FERC as a QF; (2) have made a commitment to sell the facility's output to a utility pursuant to PURPA via the use of an approved LEO Form, and (3) have received a CPCN for the construction of the facility.

The September 17, 2015 forms submitted by the Utilities include added provisions and language that do not appear to be necessary to establish the second prong of the LEO test. Therefore, the Commission finds that the previously submitted revised LEO Form submitted as Exhibit E to DNCP's Reply Comments should be approved for use by the Utilities effective 30 days after the date of this Order. DEC and DEP shall adapt the contents of this form for their use and submit its proposed form to the Commission for approval within 15 days of the issuance of this Order. Further, the Utilities shall place the forms and information on their websites that clearly shows how to establish a LEO, including the above stated change to the LEO test, and which departments must be contacted to negotiate interconnection agreements and PPAs, as well as the Public Staff's proposed language from its initial comments on their websites and on communications acknowledging receipt of the LEO forms. The Utilities shall file within 30 days of the issuance of this Order with the Commission a description of the location of the forms and information on their respective websites and the Public Staff is requested to review this filing and recommend to the Commission if the information is clearly accessible and identifiable within 10 days of the Utilities' filing. Finally, the Utilities should submit revisions to the forms, other than changes in contact information, to the Commission for approval.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence supporting this finding of fact is contained in the Initial Statement of the Public Staff and the Joint Reply Comments of DEC and DEP.

In their Joint Reply Comments, DEC and DEP indicated that they agreed with the Public Staff that Paragraph 5 of their PPAs should be revised to limit the requirement for operational information to those QFs larger than three MW as it is unlikely that DEC and DEP would need planned operational information from QFs below three MW. The Commission finds this revision appropriate and directs DEC and DEP to revise Paragraph 5 of their PPAs as provided in their Joint Reply Comments.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence supporting this finding of fact is contained in the Joint Comments and Proposed Rates of WCU and New River. WCU and New River proposed to offer variable rates based upon their wholesale cost of power and long-term fixed price rates that track DEC's Commission-approved five, ten, and 15-year long-term avoided cost rates for QFs interconnected at distribution. This is the same approach approved by the Commission in its February 21, 2014 Order in Docket No. E-100, Sub 136. No parties filed any comments or objections to WCU's and

New River's proposal. DEC is WCU's requirements supplier, and it is indirectly New River's through Blue Ridge Electric Membership Corporation. The PPA between DEC and Blue Ridge expressly treats New River's native load as if it were Blue Ridge's native load for purposes of DEC's obligations vis à vis Blue Ridge.

The Commission concludes, based upon the foregoing, that WCU's and New River's rate proposals should be accepted and that the changes approved herein with respect to DEC's avoided capacity and energy rates should be reflected in WCU's and New River's long-term avoided cost rates.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP, and DNCP shall offer long-term levelized capacity payments and energy payments for five-year, ten-year, and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity. The standard levelized rate options of ten or more years shall include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. DEC, DEP, and DNCP shall offer their standard five-year levelized rate option to all other QFs contracting to sell three MW or less capacity.

2. That DNCP shall continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's Sub 106 Order.

3. That DEC, DEP, and DNCP shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible

for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation shall be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

4. That the Utilities shall rely on publicly available data sources when calculating the installed cost of a CT for avoided capacity purposes and provide clear justifications for any adjustments made to the publicly available data. DEC and DEP shall recalculate avoided costs utilizing data from publicly available sources. DNCP shall recalculate its avoided capacity costs as shown in Figure 1 of its March 2, 2015 Initial Comments, with the appropriate adjustments as shown, but retaining the turbine costs and capacity rating for a GE Model 7FA CT as originally utilized by the 2014 Brattle Report.

5. That the methodology utilized by DEC and DEP to determine its contingency factor is reasonable for this proceeding, and the contingency factor applied in the 2014 Brattle Report relied on by DNCP is acceptable as applied to its utilization of the GE 7FA unit for determining avoided capacity costs. DEC and DEP shall adjust their contingency factor as necessary to comply with the Commission's directive that they recalculate avoided costs utilizing data from publicly available sources.

6. That DEC, DEP, and DNCP shall recalculate the installed costs of a CT excluding economies of scope and taking into account any carrying costs associated with the economies of scale.

7. That DEC and DEP shall recalculate their avoided energy rates utilizing generation expansion plan scenarios that do not include the costs of CO_2.

8. That DEC, DEP, and DNCP shall recalculate their avoided energy rates using natural gas and coal price forecasts that are constructed in a consistent manner with those utilized in their 2014 IRPs.

9. That to the extent the Utilities wish to adjust the way in which they utilize forward prices and long-term forecasts in future IRP and avoided cost proceedings, those changes shall first be proposed and approved as part of the biennial IRP proceeding before being incorporated in avoided cost calculations.

10. That DEC, DEP, and DNCP shall utilize the Black-Scholes Model or a similar model to determine the hedging value of renewable generation that is consistent with their current natural gas hedging practices. The hedging value shall be included for each year of the entire term of the QF PPA.

11. That the seasonal allocation factors utilized by the Utilities in this proceeding are reasonable. In the next biennial proceeding, the Utilities shall assemble their hourly CT operational data and marginal cost data on a season-specific basis to determine whether the allocation factors proposed in this proceeding remain reasonable.

12. That DEC and DEP shall amend the reporting language in Paragraph 5 of their standard PPAs to be consistent with the language agreed to with the Public Staff.

13. That the Reduction in Contract Capacity and Reduction in Contract Energy provisions in DEC's and DEP's Terms and Conditions are inconsistent with previous rulings of the Commission and are rejected. DEC and DEP shall be allowed to propose a provision that more narrowly addresses the harm for which they assert the penalty is designed, i.e., a reduction in production in later years because of the effect of levelized rates.

14. That the Utilities shall not unreasonably withhold consent to a proposed assignment of a standard PPA.

15. That the provision in Article 7(a)(vii) of DNCP's proposed Standard Contract that grants the utility a right to terminate a contract where the FERC grants a petition by the utility under PURPA 210(m) is unnecessary and shall be deleted.

16. That DEC and DEP shall amend their Terms and Conditions to include the language from their September 17, 2015, letter providing QFs with a reasonable opportunity to cure prior to termination of the contract.

17. That the proposal by each utility to limit the availability of standard rates to facilities within one-half mile is reasonable, with the qualification that two or more QFs under the same or affiliated ownership are eligible for the standard offer rates and terms as long as the combined capacity of those facilities does not exceed five MW. The one-half mile restriction shall only apply to facilities that use the same energy resource, and the Utilities shall include language stating that the distance between facilities will be measured from the electrical generating equipment of a facility.

18. That DEC and DEP shall amend their standard contracts to provide that a utility may terminate a contract after 30 months if a QF has failed to achieve commercial operation at any level by that date, provided that the QF shall be allowed additional time if the project in question is making reasonable progress and the QF is making a good faith effort to complete the project in a timely manner.

19. That DEC and DEP shall clarify in their standard contracts that the term begins upon the first date when electrical output is generated by a QF and delivered to the respective utility.

20. That DEC and DEP shall strike provision 1(i)(5) in their proposed Terms and Conditions, since QFs under the standard contracts are not paid unless they are generating.

21. That DEC and DEP shall delete the provisions related to interconnection in their standard contracts, with the exception of a reference to the North Carolina Interconnection Procedures, Forms, and Agreements adopted in Docket No. E-100, Sub 101, and a statement that an interconnection agreement is necessary in order to deliver output to the utility.

22. That the Utilities shall update their applicable rate schedules to reflect the utility's payment associated with reactive power for interconnection customers.

23. That the Notice of Commitment Form submitted by DNCP with its Reply Comments, shall be used, beginning 30 days after the date of this Order, by all QFs to show their compliance with the test to establish a LEO. DEC and DEP shall adapt DNCP's form their use and file their forms for approval within 15 days of the issuance of this Order.

24. That the Utilities shall place the LEO form and information on their websites that clearly shows how to establish a LEO, as clarified by this Order, and which departments must be contacted to negotiate interconnection agreements and PPAs. The Utilities shall file within 30 days of the issuance of this Order with the Commission a description of the location of the forms and information on their respective websites and the Public Staff is requested to review this filing and recommend to the Commission if the information is clearly accessible and identifiable within 10 days of the Utilities' filing.

25. That DEC and DEP shall revise Paragraph 5 of their respective PPAs to limit their right to request planned operational information to QFs of three MW or larger.

26. That WCU and New River's proposals to offer variable rates based upon their wholesale cost of power and to offer long-term fixed price rates that track DEC's Commission-approved five, ten, and 15-year long-term avoided cost rates for QFs interconnected at distribution are approved. WCU's and New River's compliance filings shall reflect the changes the Commission has approved herein to DEC's proposed five, ten, and 15-year avoided capacity rates.

27. The Utilities are required to file new versions of their rate schedules and standard contracts, in compliance with this Order, within 30 days after the date of this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

ISSUED BY ORDER OF THE COMMISSION.
This the ___17th____ day of December 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

DOCKET NO. E-100, SUB 141

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2014 Biennial Integrated Resource Plans and Related 2014 REPS Compliance Plans	)))	ORDER APPROVING INTEGRATED RESOURCE PLANS AND REPS COMPLIANCE PLANS

HEARD: Monday, March 9, 2015, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding; Chairman Edward S. Finley, Jr., and Commissioners Susan W. Rabon, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

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

E. Brett Breitschwerdt, McGuireWoods LLP, 434 S. Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For Duke Energy Progress, Inc., and Duke Energy Carolinas, LLC:

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For North Carolina Waste Awareness & Reduction Network:

John D. Runkle, 2121 Damascus Church Road, Chapel Hill, North Carolina 27516

For Southern Alliance for Clean Energy and Sierra Club:

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For North Carolina Sustainable Energy Association:

Peter Ledford, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

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

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

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

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

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

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

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

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

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

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

2014 BIENNEIAL REPORTS

This Order addresses the 2014 biennial reports (2014 IRPs) filed in Docket No. E-100, Sub 141, by Duke Energy Progress, Inc. (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (DNCP) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the lOUs.

The following parties have been allowed to intervene in this docket: Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc.

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

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

[3] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of G.S. 62-110.1(c) and G.S. 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

(CUCA); Environmental Defense Fund (EDF); Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); North Carolina Electric Membership Corporation (NCEMC); Sierra Club; and Southern Alliance for Clean Energy (SACE). The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

PROCEDURAL HISTORY

On August 29, 2014, DNCP filed its 2014 biennial IRP report and REPS compliance plan. On September 2, 2014, DEC and DEP filed their 2014 biennial IRP reports and REPS compliance plans.

On September 29, 2014, the Commission issued an Order Establishing Dates for Comments on Integrated Resource Plans and REPS Compliance Plans. That Order set January 30, 2015, as the date for filing petitions to intervene and for filing initial comments. Reply comments were due on February 13, 2015.

On January 20, 2015, the Commission issued an Order Scheduling Public Hearing on 2014 Biennial IRP Reports And Related 2014 REPS Compliance Plans. That Order set the public witness hearing for 7:00 p.m. on March 9, 2015, in Raleigh.

On January 21, 2015, DEP filed a corrected page 174 to its IRP report due to errors discovered in the calculation of the projected cost amounts contained in Table 5.

On January 28, 2015, the Public Staff filed a motion for extension of time for the filing for petitions to intervene and initial comments to February 23, 2015, and the date for reply comments to March 12, 2015. The Commission granted this motion on January 29, 2015.

On February 20, 2015, the Public Staff filed a second motion for extension of time for the filing for petitions to intervene and initial comments to March 2, 2015 and the date for reply comments to March 19, 2015. This motion was granted by the Commission on the same day.

Also on February 20, 2015, NC WARN filed its initial comments and a request for an evidentiary hearing.

On February 27, 2015, initial comments were filed by MAREC.

On March 2, 2015, initial comments were filed by NCSEA, the Public Staff and jointly by SACE and the Sierra Club.

On March 9, 2015, the public witness hearing was held in Raleigh, as scheduled.

On March 10, 2015, DEC, DEP and DNCP filed a joint motion for extension of time to file reply comments to April 9, 2015. This motion was granted on March 11, 2015.

On March 20, 2015, NC WARN filed a correction to paragraph 45 on page 27 of its initial comments filed on February 20, 2015.

On April 7, 2015, DEC, DEP and DNCP filed a joint motion for a second extension of time to file reply comments to April 20, 2015. This motion was granted by the Commission on April 8, 2015.

On April 20, 2015, reply comments were filed by DNCP, and jointly by DEC and DEP.

Public Hearing

Pursuant to G.S. 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, March 9, 2015, at 7:00 p.m., where 13 public witnesses spoke. The witnesses discussed the damage that fossil fuels do to the environment versus the benefits of generating electricity with renewable sources of energy, especially solar. It was noted that we are all stewards of the planet with a responsibility for building a healthy place for people and wildlife to flourish together.

The witnesses offered support for the EPA Clean Power Plan and an overall increase in the use of renewables and energy efficiency programs, including offering incentives to electricity consumers to invest in energy efficiency measures. There was also discussion of various issues related to coal ash cleanup.

Request for Evidentiary Hearing

In NC WARN's comments and request for an evidentiary hearing, filed on February 20, 2015, NC WARN first discusses the purpose of the IRPs and NC WARN's overriding criticism that DEC's and DEP's (collectively, Duke's) IRPs maintain the status quo of heavy reliance on fossil fuel generation. In summary, NC WARN makes four main points: (1) that Duke's growth forecasts are unrealistic; (2) that Duke's IRPs include its continued reliance on expensive and unnecessary new natural gas and nuclear plants; (3) that Duke fails to plan to use strategic purchases and transmission cooperation with other utilities and merchant plants even though Duke and other southeastern electricity providers have significant excess capacity; and (4) that Duke fails to plan for the use of cost-effective and readily available renewable energy, energy efficiency measures, and combined heat and power (CHP) resources.

NC WARN's Comments

NC WARN asserts that both DEC and DEP base their 15-year IRPs on a 1.4% annual growth in peak demand for electricity, even though actual growth in electricity demand has been flat for more than a decade. NC WARN further notes that these projections include the impact of Duke's energy efficiency programs, and estimates that the actual growth in demand projected by Duke is almost 1.9%. NC WARN submits that these projections are unrealistic because they are based on a full economic recovery and a booming growth in population. In contrast, NC WARN forecasts zero growth, which it submits is in line with the most recent growth projections by the United States Energy Information Administration (EIA), and the American Council for an Energy-Efficient Economy (ACEEE), as well as actual growth for the past decade. NC WARN states that projected demand growth is a crucial component in determining the costs for new generation facilities and that the Duke forecast, resulting in a need for 7,282 MW of capacity, will cost ratepayers over $25 billion, potentially doubling electric rates over the IRP planning period. On the other hand, NC WARN’s analysis shows that a zero growth scenario allows for the phase out of all coal plants, eliminates the need to construct new nuclear plants and reduces the need for some existing natural gas generation. According to NC WARN, this can be achieved with strengthened energy efficiency measures, a more rapid development of renewable energy, continued reliance on pumped storage, and the fostering of distributed generation, backed up with purchases from other utilities and merchant plants.

In addition, NC WARN notes that Duke's reserve margins over the IRP planning period are in excess of Duke's goal of 14.5%, with DEC's reserve margins ranging from 15% to 22.7% for summer peak (and 19.4% to 25.7% for winter peak), and DEP's ranging from 15.2% to 21.1% for summer peak (and 22.1 to 31.7% for winter peak). NC WARN opines that all utilities in the southeast region have excess capacity that should be used among the utilities to supplement each other's generation requirements, rather than building unneeded or underutilized generation. NC WARN cites and discusses the North American Electric Reliability Corporation's (NERC's) 2014 Summer Reliability Assessment. NC WARN contends that there are no compelling reasons why Duke and the other southeast utilities should continue to construct new generation without looking at mutual purchasing agreements. According to NC WARN, using average monthly peaks taken from EIA Form-714 for the shoulder months of April, May, October and November, DEC's average reserve capacity during its monthly peak is 40.6%, while DEP's is 36% and for several of these shoulder months, more than 50% of the available capacity was not needed. In addition, the excess capacity would be even more extreme assuming a flat growth rate. NC WARN discusses studies by FERC and the Lawrence Berkeley National Laboratory, and suggests that North Carolina could optimize energy efficiency and reliable distribution by implementation of a regional transmission organization (RTO), or other similar regional strategy.

NC WARN also discusses Duke's plan to build new nuclear plants. It asserts that these projects will be extremely expensive and risky, citing the cost of projects in other states. Further, NC WARN laments the drawbacks of Duke's increased reliance on natural gas plants as a baseload resource, including greenhouse gases and externalized costs of fracking and conventional drilling, refining, transportation and combustion. Further, NC WARN submits that the utilities should include an assessment of the amount of carbon emissions and other pollution as a part of their IRPs, asserting that the externalized costs from fossil fuels, such as the estimated 17 - 27 cents/kWh in health and environmental damages from coal-fired electricity, add tremendously to the cost of generating electricity with fossil fuels. NC WARN states that Duke is expected to emit approximately 34.5 million tons of carbon dioxide annually, and that the coal plants being closed by Duke are old, small coal units rarely used in the years preceding their scheduled closures, noting that the average capacity of the units that Duke has closed or projects to close is 110 MW and the age of the units at the time of retirement ranges from 50 to 89 years.

NC WARN contends that its plan for North Carolina's energy future is competition driven, its primary goal being to maximize efficiencies and thus minimize costs to ratepayers. To do this, NC WARN would increase energy efficiency and renewable energy, and encourage distributed generation to place energy sources near where they are needed. According to NC WARN, this would allow for closure of all coal-fired power plants, eliminate the need for new centralized generating plants and, as a result, decrease electric rates and pollution. NC WARN's Appendix A contains a set of pie charts comparing Duke's forecasts with those in NC WARN's energy proposal -- a zero growth scenario. NC WARN states that the most significant difference between NC

WARN’s plan and Duke’s is NC WARN's proposed increase of energy efficiency and demand-side management (DSM) programs to 19% of capacity and 24% of energy over the planning horizon, far greater than the 5% of capacity and 5.1% of energy in Duke's IRPs. Likewise, CHP and microgrids are increased to 8% of capacity and 10% of energy in the NC WARN plan, while neither is included in Duke's forecasts. Similarly, wind and solar is increased to 18% of capacity and 7% of energy in the NC WARN proposal, far greater than the 4% of capacity and 4% of energy in Duke's plan. Wholesale purchases in the NC WARN plan are 6% capacity and 6% in sales compared to 0.8% capacity and 0.2% in Duke's plan.

Moreover, NC WARN submits that some utility companies, including Florida Power and Light (FPL), argue that energy efficiency has run its course and is no longer the best option. Nevertheless, NC WARN states that a recent report by ACEEE shows that utility energy efficiency programs appear to be holding steady as the least-cost resource. Similarly, in recent long-term predictions the EIA addresses the implications of low electricity demand growth and examines various scenarios to show the effects of future savings. The EIA low electricity demand growth report discusses how variations in the amount of energy efficiency done now can affect the demand in the coming years. In the reference case, which assumes no new efficiency standards beyond those already in place, total electricity use grows by an average of less than 1% per year from 2012-2040. In addition, NC WARN discusses the energy efficiency gains made in lighting, commercial air conditioners, refrigeration units and “smart appliances.”

NC WARN further states that ACEEE’s 2014 State Energy Efficiency Scorecard ranks North Carolina number 24 among the states, with no change from the previous year. NC WARN contends that North Carolina’s utilities should take more initiative to implement energy efficiency programs, as efficiency continues to be the most cost effective option available.

In addition, NC WARN submits that the second main component of a responsible energy future is a renewable energy build-up to account for 7% of total electricity sales and 18% of total capacity in North Carolina over the planning horizon, including both retail and wholesale sales. Within this expansion, NC WARN sees solar photovoltaic (PV) systems as a tremendous resource that can provide reliable electricity, with costs continuing to fall steadily. It discusses several initiatives that are contributing to the growth of solar resources in North Carolina, and studies showing that solar has reached grid parity in ten states, and would reach grid parity in 36 of 50 states by 2016. NC WARN further contends that solar facilities are a positive asset to utility grids, providing resilience, diversity, and a hedge against increased fuel costs. In addition, NC WARN states that further development of storage technology is poised to bolster the rapid growth of distributed renewable energy such as wind and solar and provide additional grid support.

NC WARN states that it also continues to recommend the development of substantial CHP systems for commercial and industrial customers who use both heat and electricity in their facilities, and microgrid technologies putting electricity generation as close as possible to where it is needed. It states that conventional methods of producing heat and power separately have a typical combined efficiency of 45%, while CHP systems often have a total efficiency of 70 – 80%, and are versatile and flexible. Noting that currently in North Carolina there are 167 CHP facilities in operation, with a capacity of 1,541 MW, NC WARN notes that in the United States CHP represents nearly 10% of total generating capacity.

NC WARN submits that at a minimum Duke's business model will in all likelihood cause rates to double from 2009 to 2029, with additional increases in the subsequent decade depending on when new large-scale generation is added. In contrast, NC WARN asserts that its approach can provide billions of dollars in annual savings for North Carolina electricity customers, and is a responsible energy future, one that promotes job creation, a good economy, and a healthier place to live, while also doing North Carolina's share in finding solutions to climate change.

NC WARN concludes its comments with a request for an evidentiary hearing on (1) Duke's 1.5% growth rate forecast; (2) Duke's continued reliance on new natural gas and nuclear plants; (3) Duke's refusal to plan on strategic purchases and transmission cooperation with other utilities and merchant plants; and (4) Duke's failure to plan for cost-effective and readily available renewable energy, energy efficiency measures, and CHP.

Duke's Reply Comments

In its reply comments, Duke states that NC WARN essentially restated the same arguments that NC WARN made in the 2013 IRP docket and notes that those arguments were rejected by the Commission. In summary, Duke asserts that NC WARN advances unsupported positions regarding the resource plans filed by DEC and DEP. In particular, Duke asserts that NC WARN's proposed alternative resource plan is not supported by legitimate data or substantive analysis. Duke states that when it sought information from NC WARN it was informed that NC WARN did not prepare a true load forecast, but simply assumed “zero growth.” Duke states that such an assumption is entirely inconsistent with the actual data utilized to prepare the load forecasts for Duke's 2014 IRPs, and that Duke stands by the reasonableness of the load forecasts contained in its 2014 IRPs. Duke also notes that its load forecasts are supported by the Public Staff.

With regard to NC WARN's comments on Duke's proposed coal retirement and replacement plan, Duke states that NC WARN's responses to data requests indicated that NC WARN did not prepare production cost simulation models and screening models of its plan or model, nor develop any of the inputs listed in the data request, except the cost of coal and natural gas price forecasts. In addition, Duke states that according to NC WARN’s data request responses, the pie charts contained in Appendix A to NC WARN’s report were prepared by NC WARN’s researcher/paralegal. Further, in response to a data request seeking the detailed data assumptions utilized to determine the economic value of the analysis reflected in NC WARN's comments, NC WARN responded, “NC WARN has not conducted PVRR calculations, nor made assumptions associated with those calculations.” (NC WARN Response to Duke Energy’s First Data Request No. 21, March 18, 2015)

Moreover, Duke notes that NC WARN also alleges that, “If the Commission approves the Duke Energy plan, it approves a status quo threatening to bankrupt North Carolina’s economy” (NC WARN Comments, at p. 3). However, Duke states that in response to a data request asking for all workpapers, studies or other documents that were relied upon in forming this statement, NC WARN responded that it did not have any such workpapers or studies, but that its statement is explained in its comments, and based on 0% load growth and the potential that Duke's rate will double in order to pay for new generating plants. Duke maintains that NC WARN has no credible support for its allegation that Commission approval of Duke's 2014 IRP would threaten to bankrupt North Carolina’s economy.

With regard to NC WARN's assertion that Duke can retire all existing coal units and some existing natural gas units, and meet its customers' needs exclusively through a mix of new EE, renewable energy, pumped storage, distributed generation, and purchases from other utilities and merchant plants, Duke states that NC WARN has no legitimate economic analysis to support its proposed resource plan. As an example, Duke cites NC WARN's response to a data request in which NC WARN acknowledges that it has not documented the capital costs, on-going capital streams, fixed and variable O&M costs, life of asset, assumptions of federal/state tax incentives, load profiles, and capacity factors beyond the statements and footnotes in the comments. Further, in response to a data request seeking the EE and demand response costs, program participation and participation studies used to support the NC WARN comments, NC WARN stated that it had not prepared that data beyond NC WARN’s proposal for a Community Enhanced Income Qualified Energy Efficiency and Weatherization Program, as contained in NC WARN’s testimony in Docket No. E-7, Sub 1032. Duke also states that NC WARN has conducted no revenue requirements analysis for its proposed resource portfolio and, therefore, has no legitimate basis to assert that its proposal will be cost effective for Duke's customers. In addition, Duke states that WARN’s alternative resource plan was apparently developed without regard to system reliability concerns. In support of this observation, Duke notes that NC WARN’s data request responses reveal that it conducted no loss of load study. Further, when asked to explain in detail how its proposed plan will provide adequate reliability for Duke's customers, NC WARN responded simply as follows:

> As stated in the Comments, paragraph 6 and accompanying footnotes, the inclusion of a balanced mix of distributed generation and energy efficiency is more reliable than the current generation – transmission – distribution system, and especially if backed up by batteries. Electricity is placed where it is most needed both on the grid and at peak periods, and at the same time, distributed generation provides grid support services. As noted in the Comments, paragraphs 15-16, a wide variety of these sources do not require as high a reserve margin as does a system relying on a limited number of large coal and nuclear plants. In addition, NC WARN recently looked at the value of solar, including reliability, as part of the preparation of [testimony filed by NC WARN in Docket No. E-100, Sub 140].

NC WARN Response to Duke Energy’s First Data Request No. 11, March 18, 2015.

Duke asserts that NC WARN’s responses to its data requests create significant concern with the analysis presented by NC WARN that serves as the basis for NC WARN’s comments.

With respect to NC WARN's contention that Duke's reserve margins are “consistently above average for the industry” and that Duke and “all of the utilities in the Southeast region have excess capacity,” Duke notes that in the last two winters frigid temperatures pushed utility systems throughout the country to their limits. Duke states that its ability to serve its retail customers under these challenging conditions proves that NC WARN's position is wrong and misguided. According to Duke, if it had not been able to access its full portfolio of resources at the current planning reserve margins, the outcome easily could have been rolling blackouts or much higher electricity prices. In addition, NC WARN’s assertion that Duke could simply rely on excess capacity throughout the region also was proven to be incorrect during this period, as Duke's neighboring utilities confronted the same frigid temperatures and peak demands, and had little or no capacity to share with other utilities.

In conclusion, Duke submits that NC WARN's alternative resource plan would not enable North Carolina to ensure that reliable and affordable electricity is available to all customers over the IRP planning horizon. Duke acknowledges that renewable resources, EE and DSM are important and increasingly significant components of its IRPs, but states that they cannot realistically be relied upon in the almost exclusive nature that NC WARN has proposed. In contrast, Duke maintains that its IRPs present robust and balanced portfolios of diverse supply and demand side resources that will cost-effectively and reliably serve customers' needs across a range of many possible future scenarios. Accordingly, Duke requests that NC WARN's comments be disregarded and its request for an evidentiary hearing be denied.

DNCP's Reply Comments

In its reply comments, DNCP notes that NC WARN's concerns are not focused on DNCP's 2014 IRP. In addition, DNCP opines that NC WARN has not presented any compelling issues or reasoning in support of its request for an evidentiary hearing. Finally, DNCP states that if a hearing is held it should be limited to issues regarding Duke's 2014 IRPs.

Discussion

General Statute 62-110.1(c), in pertinent part, requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity." In State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation, 105 N.C. App 136, 141, 412 S.E.2d 166, 170 (1992), the Court of Appeals discussed the nature and scope of the Commission's IRP proceedings. The Court affirmed the Commission's conclusion that

> [t]he Duke and CP&L plans were "reasonable for the purposes of [the] proceeding" before it. That is to say, the plans submitted by Duke and CP&L were reasonable for the purpose of "analy[zing]…the long-range needs for expansion of facilities for the generation of electricity in North Carolina…" See N.C. Gen. Stat. § 62-110.1(c).

The Court further explained that the IRP proceeding is akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific projects at a later time. On the other hand, it is not an appropriate proceeding for the Commission to use in issuing "directives which fundamentally alter a given utility's operations." With regard to the Commission's authority to issue specific directives, the Court cited the availability of the Commission's certificate of public convenience and necessity (CPCN) proceedings and complaint proceedings. Id., at 144, 412 S.E.2d at 173.

In the context of considering whether the utilities' IRPs are reasonable for planning purposes, the Commission gives substantial weight to the underlying data, modeling and analyses presented by the utilities, the Public Staff and the intervenors. With respect to the credibility of Duke's load forecasts, as more fully discussed later in this Order, the Public Staff reviewed Duke's load forecasts and concluded that Duke employed accepted statistical and econometric forecasting practices. Therefore, the Public Staff supports the reasonableness of Duke's load forecasts for planning purposes. Comments of the Public Staff, at 12-18.

Likewise, the Public Staff reviewed Duke's reserve margins and found them to be reasonable for planning purposes. The Public Staff describes the Loss of Load Expectation (LOLE) probabilistic assessment employed by Duke in estimating its reserve margins. The Public Staff also discusses the tight reserve margins experienced by Duke during the unusually cold temperatures in 2014 and 2015, and notes that neighboring utilities were experiencing the same tight supplies. Comments of the Public Staff, at 37-41.

In contrast, it does not appear that NC WARN employed specific data or modeling techniques to support its load forecast of 0% growth and its criticisms of Duke's reserve margins. The Commission appreciates and is interested in the statistics and analyses of EIA, NERC ACEEE and other national organizations. On the other hand, the Commission's charge in this proceeding is to determine whether the utilities' IRPs are reasonable planning tools for North Carolina's electric needs. Regional and national forecasts simply do not carry the weight of the specific, data-based analyses employed by Duke and verified by the Public Staff.

Similarly, in the context of considering whether the utilities' IRPs are reasonable for planning purposes, the Commission gives substantial weight to the goal of adequate and reliable electric service. Planning for adequacy and reliability requires careful analysis that gives due consideration to a myriad of factors, not just cost. NC WARN's proposals rely heavily on renewable resources and energy efficiency programs. However, it does not appear that NC WARN has given due consideration to factors such as load profiles, the future of tax incentives for renewable resources, capacity factors of renewable resources, transmission availability and energy efficiency program participation rates. On the other hand, the Public Staff discusses its review of Duke's extensive resource modeling techniques, including Duke's use of the System Optimizer and Planning and Risks models, and finds Duke's analyses to be reasonable for planning purposes. Comments of the Public Staff, at 46-59. In addition, the Commission notes that in a CPCN proceeding for an electric generating plant G.S. 62-110.1(d) requires the Commission to consider the applicant's arrangements for purchased power, power pooling and other such interchanges. Further, in CPCN proceedings for coal or nuclear plants G.S. 62-110.1(e) requires the applicant to demonstrate that energy efficiency measures, DSM, renewable resources and CHP, or any combination thereof, would not be as reliable or cost-effective as the proposed generating plant. Therefore, NC WARN's proposals can be addressed directly and appropriately at the time that Duke applies for a CPCN to build additional generating facilities in North Carolina.

Pursuant to Commission Rule R8-60(j), an intervenor may file an IRP of its own with respect to any utility. If it chooses to propose an alternative IRP, the intervenor's IRP should conform to the information and analytic requirements of Rule R8-60(c) – (i). To the extent that NC WARN intended for its comments to be construed as an alternative IRP for Duke, the Commission finds and concludes that NC WARN's proposal was inadequate with respect to data, modeling and analysis.

On March 9, 2015, the Commission held a public hearing in Raleigh for the purpose of receiving testimony from Duke's and DNCP's ratepayers. Thirteen witnesses testified regarding their views and concerns on a wide range of topics, including renewable energy, energy efficiency, coal ash disposal, coal plant retirements and CHP. The Commission has fully considered the testimony of these public witnesses, along with numerous statements of position from ratepayers on these and other matters, in arriving at its conclusions in this Order. This information, plus the IRPs and the parties' comments and reply comments, provide the Commission with an extensive record in this docket. Having reviewed the record and considered the parties' arguments, the Commission concludes that the issues raised by ratepayers at the hearing and in their statements of position, as well as those raised by NC WARN in its comments and request for an evidentiary hearing, have been adequately addressed by Duke.

The Commission finds and concludes that the record in this proceeding includes sufficient detail to allow the Commission to decide all contested issues without the necessity of a further evidentiary hearing. As a result, the Commission is not persuaded that there is good cause to grant NC WARN's motion that the Commission hold an evidentiary hearing in this docket. Therefore, the motion should be and is denied.

FINDINGS OF FACT

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

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

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

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

4. DEP, DEC and DNCP have adequately addressed the Public Staff's specific recommendations regarding the 2014 IRPs.

5. The IOUs included a full discussion of REPS compliance and their plans should be approved.

6. DEP, DEC and DNCP have adequately addressed the issues raised by the intervenors.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

PEAK AND ENERGY FORECASTS

The Public Staff has reviewed the 15-year peak and energy forecasts (2015–29) of DEP, DEC, and DNCP. The compound annual growth rates (CAGR) for the forecasts are within the range of 1.0% to 1.4%.

All of the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. As with any forecasting methodology that uses computer modeling, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future.

In assessing the reasonableness of the forecasts, the Public Staff first compared the utilities' most recent weather-normalized peak loads to those forecasted in their 2013 IRPs. The Public Staff then analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2009 IRPs by comparing them to their actual peak demands and energy sales. A review of past forecast errors can identify trends in the IOUs' forecasting and assist in assessing the reasonableness of the utilities' current and future forecasts. Finally, the Public Staff reviewed the forecasts of other adjoining utilities and the SERC Reliability Corporation.

In their 2013 IRPs, all three utilities predicted that their 2014 system peaks would occur in the summer. However, during January 2014, the IOUs reported several hourly peak loads that were greater than the summer peak loads that occurred later that year. Additionally, in February 2015, both DEC and DEP experienced all time system peaks.

DEP

DEP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.3%, as compared to growth rates of 1.2% and 0.9% in its 2013 and 2012 IRPs, respectively. Without the reduction in peak demand resulting from the implementation of its energy efficiency (EE) programs, DEP would expect its summer peaks to grow at a rate of 1.6%. The average annual growth of its summer peak, which DEP considers its system peak, is forecasted to be 190 megawatts (MW) for the next 15 years according to the 2014 IRP, in comparison to a predicted growth of 171 MW in DEP's 2013 IRP. DEP predicts that in 15 years, the load reductions from its new EE programs will reduce its annual peak load by approximately 4%, which is similar to its projection in its 2013 IRP. DEP assumes that it can actively reduce 7% of its peak load by using its demand-side management (DSM) resources, which it considers a capacity resource.

The Public Staff observed that DEP's forecast of its winter peak loads reflects a slightly lower CAGR of 1.2% than that of its summer peaks, with winter peaks approximately 600 MW less than the forecasted summer peaks on average. DEP's energy sales, including the impacts of its EE programs, are predicted to grow at a CAGR of 1.0%, as compared to 1.4% and 1.0% in its 2013 and 2012 IRPs, respectively. DEP predicts that over the next 15 years, the megawatt-hour (MWh) reductions from its EE programs will cause a reduction in annual energy sales of 1% in 2015, increasing to approximately 4% in 2029. This is similar to the projection in DEP's 2013 IRP.

The Public Staff's review of DEP's actual and weather adjusted peak load forecasting accuracy for one year shows that the forecasts in DEP's 2013 IRP overpredicted the 2014 summer peak load by 12% and underpredicted the 2014 winter peak forecast by 12%. However, the forecast errors are reduced to 5% and below when the two peaks are adjusted to remove the impacts of an unusually mild summer peak-day temperature and an abnormally cold peak-day winter temperature.

The Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEP's peak and energy forecasts are reasonable and that DEP has employed accepted statistical and econometric forecasting practices. Accordingly, the Public Staff asserted that DEP's peak load and energy sales forecasts are reasonable for planning purposes.

DEC

Regarding DEC, the Public Staff responded that DEC's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.4%, identical to the 1.4% forecast in its 2013 IRP and similar to the 1.7% growth rate projected in its 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEC would expect its summer peaks to grow at an average of 1.7% each year for the next 15 years. The average annual growth of its summer peak, which DEC considers its system peak, is forecasted to be 286 MW for the next 15 years, as opposed to the 283 MW and 321 MW forecast in its 2013 and 2012 IRPs, respectively. DEC predicts that in the next 15 years, the load reductions from its new EE programs will reduce its annual peak load by approximately 5%, similar to its projection in its 2013 IRP. The plan also assumes that the Company can reduce 5% of its load by 2029 by using its DSM resources, considered a capacity resource. DEC's forecast of its winter peak loads reflects a slightly higher CAGR of 1.5%; however, on average, the winter peaks are approximately 1,180 MW lower than the forecasted summer peaks.

The Public Staff stated that DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 1.0%. This growth rate is less than the 1.5% and 1.7% predicted in its 2013 and 2012 IRPs, respectively. DEC predicts that its EE programs will reduce its energy sales by approximately 6% by 2029.

The Public Staff's review of DEC's actual and weather adjusted peak load forecasting accuracy for one year shows that the forecasts in its 2013 IRP overpredicted its summer peak load by 9% and underpredicted its 2014 winter peak load by 8%. However, the forecast errors are reduced to 3% and below if the two peaks are adjusted to remove an unusually mild summer peak-day temperature and an abnormally cold winter peak-day temperature.

The Public Staff pointed out that, for several years, DEC's forecasts for both peak demand and energy sales have consistently been higher than the actual peak demands and sales. In contrast, DEP's and DNCP's forecasts generally have generated at least one annual peak prediction that was less than the actual peak. The five-year trend of overpredicting DEC's loads is still apparent even when the abnormally high winter peak load in 2014 is used instead of the summer peak load of 2014. Using this calculation, DEC's peak load was overpredicted by an annual average of 435 MW.

According to the Public Staff, the importance of load forecast accuracy cannot be overstated given that the resource expansion plan is designed to serve the forecasted load at the least cost. The adoption of a forecast with a lower growth rate of 1.0%, as opposed to DEC's forecasted 1.4%, would result in the elimination of the need for at least one or more of the planned large baseload units, while maintaining a reasonable reserve margin over the 15-year plan. A 1% growth rate is hypothetical; however, this lower growth rate, in comparison with DEC's estimate of 1.4%, is closer to DEC's recent peak demand growth rate.

Nonetheless, the Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEC's peak and energy forecasts are reasonable and that DEC has employed accepted statistical and econometric forecasting practices. The Public Staff continues to be concerned with DEC's pattern of overforecasting more often than underforecasting its load. As noted in the Public Staff's comments on the 2013 IRPs, after the merger of DEP and DEC, DEP adopted DEC's forecasting methods, even though DEP's forecasting of its energy sales and peak demands before the merger had been more accurate than DEC's forecasting. Before the merger, DEP typically relied on a monthly-based econometric model with end-use data over a span of ten or more years of historical data for its energy sales forecasts. This model was used for over 30 years, and during these years, DEP used the load factor method to forecast its peak demands. DEC has also used econometric models. It has made various modifications to the general econometric equations used for its energy sales and peak demand forecasts over the last 30 years, but is now planning to replace its current model with a monthly peak model. While DEC's 2014 forecasts are reasonable for planning purposes, the Public Staff recommends that DEC continue to review its forecasting models carefully, including planned changes to identify further improvements.

DNCP

The Public Staff observed that DNCP's 15-year forecast predicts that its adjusted summer peaks will grow at a CAGR of 1.0%, a decrease from the 1.2% and 1.5% growth rates projected in its 2013 and 2012 IRPs, respectively. Without the reduction in peak demand resulting from the implementation of its EE programs, DNCP would expect its summer peaks to grow at 1.4%. The average annual growth of its summer peak is forecasted to be 198 MW for the next 15 years, in comparison to the 239 MW forecast in the 2013 IRP. DNCP predicts that in the next 15 years, the load reductions from its EE programs will reduce its annual peak load by approximately 2%, an increase from the 1% forecast in its 2013 IRP. DNCP predicts that load reductions from the activation of its DSM programs will reduce its peak load by approximately 1% by 2029. While DNCP's forecast of its winter peak loads reflects a slightly higher CAGR of 1.1% relative to the 1.0% CAGR for its summer peaks, the winter peaks are approximately 3,382 MW less than the forecasted summer peaks on average.

The Public Staff indicated that DNCP's energy sales are predicted to grow at an average annual rate of 1.1%, a decrease from the 1.4% and 1.6% growth rates predicted in its 2013 and 2012 IRPs, respectively. DNCP predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 3% by 2029.

The Public Staff's review of DNCP's actual peak load forecasting accuracy for one year shows that its 2013 IRP overpredicted the Company's summer peak load by 6% and underpredicted its 2014 winter peak load by 11%. As with DEC and DEP, the forecast errors are somewhat attributable to the mild summer peak- day temperatures and abnormally cold peak-day winter temperatures for 2014.

The Public Staff believes that the economic, weather-related, and demographic assumptions underlying DNCP's peak and energy forecasts are reasonable and that DNCP has employed accepted statistical and econometric forecasting practices; therefore, the Public Staff concludes that DNCP's peak load and energy sales forecasts are reasonable for planning purposes.

PUBLIC STAFF'S CONCLUSIONS ON PEAK LOAD FORECASTS

The five-year forecast errors based on the summer peak forecasts filed in the 2009 IRP have improved from those calculated based on the 2008 IRPs, especially for DEC. Nevertheless, the Public Staff remains concerned with DEC's tendency to overforecast its summer peaks. However, the Public Staff believes that DEC's move to a monthly model may correct this tendency.

A second concern involves the unexpectedly large increases in the demand for electricity at the 2014 system peaks for all three IOUs that occurred in January at abnormally low temperatures. Identifying and properly forecasting the shape of customers' response to abnormally cold conditions can be challenging due to its non-linear nature that may not be fully captured in the current equations in the IOUs' peak forecast models. As such, the Public Staff recommends that the companies review their winter peak equations in order to better quantify the response of customers to abnormally low temperatures.

SUMMARY OF GROWTH RATES

The following table summarizes the growth rates for the IOUs' system peak and energy sales forecasts based on their IRP filings.

2015- 29 Growth Rates

(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	1.3%	1.2%	1.0%	190
DEC	1.4%	1.5%	1.0%	286
DNCP	1.0%	1.1%	1.1%	198

SYSTEM PEAKS AND USE OF DSM RESOURCES

DEP's 2014 annual system peak of 14,159 MW occurred on January 7, 2014, at the hour ending 8:00 a.m., at a system-wide temperature of 11 degrees. The 11 degrees is significantly colder than the 18 degrees assumed in the winter peak load forecast. DEP's 2013 and 2012 peaks were 12,166 MW in August 2013 and 12,770 MW in July 2012. The 2014 peak occurred after several days of abnormally cold temperatures. The Company projected its day-ahead operating reserves at 5.8%. In addition to the abnormal temperatures, several of the Company's generating units were down with forced outages, resulting in available operating reserves of only 0.19% at the time of its actual peak. Due to its low operating reserves, DEP activated all of its DSM resources and reduced its peak demand by 383 MW as follows: EnergyWise Home for 9 MW, Commercial, Industrial, and Government (CIG) Demand Response Automation for 6 MW, Distribution Service Demand Response (DSDR) [1] for 157 MW, and Curtailable Rate programs for 211 MW.

DEC's system peaked at 19,151 MW on January 30, 2014, at the hour ending 8:00 a.m. at a system-wide temperature of 12 degrees. The 12 degrees is significantly colder than the 18 degrees assumed in the winter peak load forecast. Given the forecasted weather conditions and unit availability, DEC had anticipated that its day-ahead operating reserves would be approximately 18%. However, at the actual time of system peak, its operating reserves fell to 2.4%. At this time, the Company did not activate any of its DSM programs. However, during its second highest peak, which occurred on January 7, 2014, the Company did activate its DSM programs, reducing load by 478 MW. At hour ending 8:00 a.m. that day, DEC anticipated having 10% available operating reserve; however, its actual level of operating reserves fell to 0.24%, similar to DEP's 0.19% operating reserves. The Public Staff notes that the extended unusually cold temperatures resulted in higher than projected energy use and that coincident forced outages (also related to the extended abnormally cold temperatures) also contributed to the low reserves available for both DEC and DEP. During the morning hours on January 7, DEC activated its Interruptible Service for 124 MW, Standby Generation Service for 31 MW, PowerShare Mandatory for 310 MW, and Power Share Generators for 13 MW. On the next day, DEC activated the same four programs with similar load reductions. In regard to DSM activations during the Company's highest 15 peak loads, DEC used DSM on three occasions, with its third and final DSM activation on September 2, 2014, obtaining a 202 MW load reduction from its PowerShare Mandatory program. DEC's 2013 IRP projected 561 MW of available DSM capacity, while in actuality only 478 MW, or 85%, of the 2013 projection was available.

DEC has indicated to the Public Staff that its DSM resources are used in near emergency situations to maintain reliability and has pointed to its higher level of available operating reserves at the time of the peak and other near peak events that forestalled the need to use DSM. DEC also stressed two additional important considerations with regard to DSM activations. First, each DSM program has different timing considerations regarding advance notice to participating customers and customer response times that may affect the ability of the utility to call on a particular customer. Second, over-utilization of DSM programs could reduce the willingness of customers to participate in the programs, negatively impacting the long-term availability of those programs for reliability purposes.

The Public Staff recognizes these important considerations and agrees the utilities must take them into account in deciding when and to what extent to activate their DSM programs. Nonetheless, the Public Staff believes that DEC could take greater advantage of its DSM programs by activating them on a more frequent basis, both for reliability and for reduction in fuel costs.

DNCP's 2014 annual system peak of 16,840 MW occurred on January 30, 2014, at the hour ending 8:00 a.m., unlike its 2013 and 2012 system peak loads of 16,366 MW and 16,787 MW, respectively, both of which occurred in the summer. At the time of the 2014 peak, DNCP called on its Distributed Generation Pilot[2] (DG) for a load reduction of 10 MW, which is less than the 34 MW of DSM identified as being available in DNCP's 2013 IRP.

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[1] The Commission has classified DSDR as an EE program, but DEP generally uses it as it would a DSM program.

[2] The Distributed Generation Pilot is approved only in Dominion's Virginia jurisdiction.

THE PUBLIC STAFF'S COMMENTS ON DSM ACTIVATIONS

One area of concern for the Public Staff in its review of the DSM activations at the time of the 15 highest hourly peaks for each utility is the actual DSM load reductions that are realized when system operations call on DSM as a resource. There is a substantial difference between the DSM load reduction actually realized on the 15 days when peak demand was highest for all three utilities and the amount of DSM load reduction forecasted.

As noted previously, despite complete activations of its DSM programs, DEP had only 76% of its projected DSM capacity actually available at the system peak on January 7, 2014. Likewise, DEP's use of Energy Wise in the summer resulted in 107 MW of capacity reduction out of the 230 MW forecasted to be available.

During DEC's two uses of its Power Manager Program during the summer, the program produced a load reduction of 61% of the reduction forecast in the IRP for planning purposes. For DEC's Power Share-Mandatory program and Schedule SG customers, the load reduction realized from both programs was approximately 85% of the reduction forecast in the IRP. However, Schedules IS achieved a load reduction of 95% of the total reduction DEC had indicated to be available.

DNCP's DSM capacity reductions were also below the amount forecast in its IRP, with the Residential Air Conditioning Cycling program achieving 74% of its forecasted amount of capacity reductions, and the Customer Distributed Generation program achieving 65% and 71% of its forecasted winter and summer season capacity reductions, respectively.

A second area of concern for the Public Staff involves differences in DSM resources available in the winter as opposed to the summer because winter season DSM has typically not been found to be cost effective. Each North Carolina utility has a summer air conditioning load control program, customer-owned standby generation, and load curtailment programs. Standby generation and load curtailment resources are available to each utility in the winter season. However, DEP is the only utility that has any dispatchable DSM for use during the winter season (the Heat Strips and Water Heater measures in the EnergyWise program). While DSDR has been classified by the Commission as an EE program, it was used by DEP several times in both the winter and summer seasons to reduce peak demand.

The Public Staff has two recommendations to address these concerns regarding DSM. First, the DSM resources identified in the IRP should represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity. Through evaluation, measurement, and verification (EM&V) of these DSM programs, utilities should identify the enrolled DSM capacity and the reasonably expected level of load reduction that can be reliably called on during a DSM event, winter and summer. Second, the recent rise in winter peak demands suggests that the IOUs should pursue a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands.

RESERVE MARGINS AND RESERVE MARGIN ADEQUACY

In its comments, the Public Staff noted that DEP and DEC use a recommended system reserve margin based on the Loss of Load Expectation (LOLE) probabilistic assessment. The LOLE is a metric that targets the probability of the loss of load on one day in a ten-year period, or one firm load shed event resulting in unserved energy for a firm customer on one day in a ten-year period. The reserve margins that correlate with this LOLE are approximately 14.5% for DEP and DEC. Because generating capacity is added in block amounts, DEP and DEC target as an acceptable reserve margin a range of approximately 14.5% – 17.0%. Additional analysis was performed to verify the adequacy of these target reserve margins following the implementation of the Joint Dispatch Agreement (JDA) between DEP and DEC. Based on this subsequent review, DEC and DEP utilize a 14.5% target planning reserve margin.

DNCP utilizes the PJM capacity planning process for long- and short-term planning of capacity needs. PJM's 2013 Reserve Requirement Study recommends use of a reserve margin of 15.7% to satisfy the reliability criteria required by the North American Electric Reliability Corporation (NERC), Reliability First Corporation, and PJM's Planned Reserve Sharing Group. DNCP utilizes a coincidence factor to account for the historically different peak periods between DNCP and PJM, and therefore its ability to meet its PJM reserve requirements. This coincidence factor reduces the Company's reserve margin requirement to 11.2%. DNCP also includes a 16.2% upper margin that is commensurate with the upper bound where the Reliability Pricing Model (RPM) market auction has historically cleared. The DNCP planning reserve margin remains at 11.2%.

According to the Public Staff, for the planning period 2015 to 2029, the range of summer reserve margins reported by the electric utilities continues to be similar to those used in previous annual reports. For this time period, the planned reserves are:

Electric Utility	Planned Reserve 2015-2029	Target Reserve Margin
DEP	15.2% to 21.1%	14.5%
DEC	15.0% to 21.2%	14.5%
DNCP	11.2% to 17.4%	11.2%

The Public Staff explained that DEP's IRP indicates that DEP will meet its projected reserve margin targets for the planning period and will exceed the minimum 14.5% by three percent or more in 2015-17 due to a decrease in the load forecast. The IRP also states that the reserves exceed the minimum target by three percentage points or more in 2022 and 2023 as a result of the addition of large combined-cycle (CC) facilities.

DEC's IRP indicates that its reserve margins will meet its projected reserve margin targets for the planning period and will exceed the minimum 14.5% by three percent due to a decrease in the load forecast in 2015, and in subsequent years (2020, 2021, 2024, and 2025-2028) coincident with large unit additions.

DNCP participates in the PJM market and, through the RPM auction, has obtained a commitment for additional capacity purchases above and beyond the existing identified firm purchases to ensure that its reserve margins meet the target of 11.2% reserves in 2014 and thereafter.

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

The Public Staff does note that these projected reserve margins are based on the load growth estimates and the projected peaks forecast by the Companies. Actual winter peaks for 2014 and this year have exceeded the estimates by a significant amount due, in part, to abnormally cold weather. Forced outages coincident with the winter peaks resulted in very low available reserves at the time of DEP's system peak on January 7, DEC's peak on January 30, and the most recent peak of DEC and DEP, which occurred on February 20, 2015.[1] This abnormal weather also stressed the available capacity for neighboring utilities. In particular, South Carolina Electric & Gas' shed 300 MW of its load during the polar vortex of 2014. Good system operation, firm and spot purchases, employment of DSM, appeals to the public to reduce load, and sharing of information, forecasts, and resources with neighboring utilities resulted in the utilities meeting their capacity needs to date. With two winters in a row in which the system operators have encountered some level of difficulty securing adequate winter capacity, the Public Staff recommends that DEC and DEP review their load forecasting methodology to ensure the assumptions and inputs remain current and that appropriate models quantifying customers' response to weather, especially abnormally cold winter weather, are employed.

As such, the purpose of the Public Staff's discussion is not to examine the precise reasons for the low operating margins of DEC and DEP on January 7, 2014, but rather to highlight for the Commission how far these operating margins fell. As noted in the previous section on load forecasts, the Pubic Staff recommends that DEC and DEP work to improve their forecasting accuracy, especially with regard to possible abnormally cold weather events. DEC and DEP have indicated in discussions with the Public Staff that rather than calculating an independent winter peak forecast, as they do for the summer peak, they derive the winter peak based on a ratio applied to the summer peak. The Public Staff believes that the use of a monthly peak model, as used by DNCP, may lead to better summer and winter peak forecasts. Secondly, the Public Staff recommends that DEC and DEP assess why their actual DSM capacity was significantly less than expected. Third, the Public Staff recommends that DEC and DEP continue to evaluate modifications to or maintenance of their systems to improve their operations during periods of extreme cold temperatures, so the expected capacity will be available and reserve margins maintained.

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

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[1] Forced outages did not occur at the time of DNCP's peak on January 30, 2014, but both before and after this peak.

DEC'S CARBON NEUTRALITY PLAN

DEC included as Appendix K to its 2014 IRP a Cliffside Unit 6 Carbon Neutrality Plan. This Plan incorporated actions required under the Greenhouse Gas Reduction Plan, as well as DEC's additional obligations related to its Cliffside Unit 6 air permit to: (a) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Table K.1, (b) accommodate, to the extent practicable, the installation and operation of future carbon control technology at Cliffside Unit 6, and (c) take additional actions as necessary to make Cliffside Unit 6 carbon neutral by 2018.

The Carbon Neutrality Plan submitted by DEC in its 2014 IRP is very similar to the one approved in the 2014 IRP Order, and incorporates the same implementation schedule, with updated values for the estimates of conservation, renewable energy, and nuclear uprates. The Public Staff considers this plan update to represent a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.

RELICENSING OF EXISTING NUCLEAR PLANTS

As discussed in the Public Staff's comments on the 2013 IRPs, one of the significant issues faced by the IOUs is the pending expiration of operating licenses for significant nuclear energy resources in the next 20 to 30 years. The following table summarizes the current license expiration dates for the nuclear facilities owned by DEP, DEC, and DNCP.

Potential Nuclear Retirements

Name	Utility	Summer Capacity (MW)	License Expiration Date
Robinson Unit 2	DEP	741	July 2030
Surry Unit 1	DNCP	838	May 2032
Surry Unit 2	DNCP	838	January 2033
Oconee Unit 1	DEC	846	February 2033
Oconee Unit 2	DEC	846	October 2033
Oconee Unit 3	DEC	846	July 2034
Brunswick Unit 2	DEP	938	December 2034
Brunswick Unit 1	DEP	932	September 2036
North Anna Unit 1	DNCP	838	April 2038
North Anna Unit 2	DNCP	835	August 2040
McGuire Unit 1	DEC	1129	June 2041

McGuire Unit 2	DEC	1129	March 2043
Catawba Unit 1	DEC	1129	December 2043
Catawba Unit 2	DEC	1129	December 2043
Harris Unit 1	DEP	928	October 2046

The Public Staff notes that recent draft revisions to technical guidance and regulation by the Nuclear Regulatory Commission (NRC) and others may ultimately provide an option to operators of commercial nuclear power facilities for extension past the current 60-year licenses. Potential extension of licenses would be evaluated based on the specific risks and costs associated with individual units. The NRC has stated that it expects the first extensions beyond 60 years to be filed in the 2018 to 2019 time frame. Relicensing could mitigate the currently expected combined (DNCP, DEP, and DEC) loss of nuclear baseload generation of 7,013 MW in the 2030 to 2034 time frame and the loss of an additional 7,162 MW in the 2038 to 2046 time frame. The Public Staff recommended in its comments filed in response to the 2013 IRPs that in their 2014 IRPs, the IOUs consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing in their IRPs. No scenarios were included in the 2014 IRPs that discussed this issue.

While it acknowledges the uncertainty of this potential, the Public Staff notes reports that DEC's Oconee and DNCP's Surry nuclear plants have been identified as leading candidates for license extension beyond 60 years.[1] Extensions of the licenses for the existing units would dramatically change the utilities' energy needs and therefore the forecasted construction schedule of new generation. The Public Staff repeats its recommendations that the IOUs consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing in their IRPs.

NON-UTILITY GENERATION (NUG)

Commission Rule R8-60(i)(2)(iii) requires each electric utility to provide in its biennial IRP report a list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities. DEC, DEP, and DNCP each provided a list of NUGs in compliance with this requirement.

DEP reported 11 firm wholesale purchase contracts with a combined capacity of 1,749 MW. DEP also reported 856.1 MW of customer-owned generation in North Carolina and 156.4 MW of customer-owned generation in South Carolina. In addition, DEP receives approximately 95 MW from Southeastern Power Administration (SEPA) for wholesale customers located within DEP's control area.

[1] http://www.nytimes.com/2014/10/20/business/power-plants-seek-to-extend-life-of-nuclear-reactors.html?emc=eta1&_r=0

DEC reported 20 firm wholesale purchase contracts with a combined capacity of 231 MW. DEC also reported 316.8 MW of customer-owned generation in North Carolina and 40.6 MW of customer-owned generation in South Carolina as of June 2014.

DNCP reported nine NUGs with a combined capacity of 1,747.4 MW, which it included in its IRP as firm capacity. DNCP also reported ten "behind the meter" (BTM) NUGs in North Carolina with a combined capacity of 30.8 MW, and 19 BTM NUGs in Virginia with a combined capacity of 217.3 MW. These BTM NUGs are considered non-firm and were not included in DNCP's IRP as firm capacity. DNCP also reported other customer-owned generators of 53.4 MW in North Carolina and 2,795.9 MW in Virginia, which also were not included in its IRP as firm capacity.

WHOLESALE CONTRACTS FOR PURCHASE AND SALE OF POWER

Each utility, with the exception of DNCP, provided a list of firm wholesale purchased power contracts; DNCP stated that its contracts with NUGs are considered firm capacity resources and are included in its IRP. In addition, each utility provided a discussion of recent and pending RFPs and a list of firm wholesale power contracts during the planning horizon in compliance with Rule R8-60(i)(4).

TRANSMISSION FACILITIES

Pursuant to the 2014 IRP Order, the electric utilities included a copy of their most recent FERC Form No. 715 (Annual Transmission Planning and Evaluation Report) and discussed with the Public Staff detailed information concerning their transmission line inter-tie capabilities, transmission line loading constraints, planned new construction and upgrades, and NERC compliance within their respective control areas for the planning period under consideration. Each electric utility appears to be in compliance with the Commission's filing requirements and NERC transmission reliability standards.

DSM AND EE

The Public Staff's review of the DSM/EE forecasts and programs indicated that each IOU complied with the requirements of Commission Rule R8-60 and previous Commission orders regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. Each IOU included information about its respective DSM and EE portfolios[1] that is largely the same as reported in the 2013 IRPs. Each IOU's forecast of DSM and EE resources and the forecast of peak demand and energy savings from those programs was slightly different from the forecast in the last IRP, but none changed by more than 10%, so no explanation of the drivers behind those changes was required. Unlike last year, DEP and DEC presented their DSM/EE forecast data in the same manner, allowing a clearer understanding of each utility's DSM/EE projections. Finally, as recommended by the Public Staff in its comments on the 2013 IRPs, all three utilities separately delineated the existing EE savings that were incorporated in the load forecasts.

[1] For purposes of these comments, the Public Staff includes time-of-use (TOU) rate schedules in its discussion of DSM and EE.

According to the Public Staff, the IOUs included a discussion of new initiatives to expand their DSM/EE portfolios. DNCP currently has three new programs before the Virginia State Corporation Commission, which it intends to file in North Carolina later this year. DEP discussed five programs being considered for implementation (three were approved for implementation in December 2014). DEC did not offer any specific programs being considered for future implementation.

The Public Staff also notes that DNCP completed a new market potential study in late 2014, but indicated to the Public Staff that the findings of the study were still being reviewed at this time before being released. Both DEP and DEC updated their studies in 2013.

With respect to TOU and other curtailable service rates, DEC and DEP are both conducting pilot TOU studies to determine the feasibility of new TOU and curtailable rate schedules. Those studies are ongoing and are expected to produce results in the next two years. The Public Staff continues to recommend that the IOUs implement all cost effective DSM and EE, and also TOU rate schedules. As discussed earlier in these comments, greater emphasis on meeting the wintertime peak demands may warrant reevaluation of DSM and TOU resources.

ASSESSMENT OF ALTERNATIVE SUPPLY-SIDE ENERGY RESOURCES

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

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

EVALUATION OF RESOURCE OPTIONS

Commission Rule R8-60(i)(8) requires each utility to include in its IRP a description and summary of the results and analyses of potential resource options and combinations of options. The IOUs indicate in their IRPs that they use accepted models that identify the least-cost mix of resources required to meet the future energy and capacity needs in an efficient and reliable manner. DEP and DEC utilize the System Optimizer and Planning and Risk models to determine the dispatch and production costs for their system; DNCP utilizes the Strategist model.

DEP' S AND DEC' S JOINT PLANNING SCENARIO

The Public Staff noted that DEP and DEC included in their IRPs a Joint Planning Scenario that examines the potential for them to share capacity,[1] as compared to the JDA, which allows non-firm energy transactions. A shared capacity arrangement between DEC and DEP would require approvals from the FERC, as well as the North Carolina and South Carolina utility regulatory commissions. If allowed, the Joint Planning Scenario produces a total present value revenue requirement (PVRR) savings of approximately $300 million over the 2029 planning horizon by delaying the need for two 866 MW combined-cycle units (CC) by one year and eliminating the need for 396 MW from two combustion turbine units (CT). As noted, this portfolio spans a fifty-year period and includes three new nuclear units shared by DEP and DEC, which would help to maintain current nuclear capacity and fleet generation diversity as the existing nuclear units are retired.

QUANTIFICATION OF THE VALUE OF FUEL DIVERSITY AND REDUCED RISK

The Public Staff observed that the evaluation of resource options in the IRP is an ongoing process. Deferring decisions may provide more certainty in resource planning and reduce the likelihood of selecting a resource mix that is not least-cost. A more diverse generation portfolio may mitigate future cost variability and the risk of relatively high energy prices in the future. However, the benefits of avoiding potentially high prices must be weighed against the known costs and the potential for unknown costs of building new generation, particularly nuclear.

The Public Staff recommends that the utilities continue to develop methods of quantifying the benefits of fuel diversity. The Public Staff also recommends that the utilities provide not only the PVRR for the possible resource expansion plans, but also an estimate of the annual rate impacts of such plans levelized over the life of the resource additions. A calculated rate impact on a levelized per kilowatt-hour (kWh) basis would provide a clearer understanding of the ratepayer impacts of future portfolios. If it would make the rate impact study for each portfolio less complicated and burdensome to perform, the utilities could calculate only the impact of the annual revenue requirement on the Company's average overall rates for the last year of the 15-year plan.

NATURAL GAS ISSUES

Ordering Paragraph No. 15 of the 2014 IRP Order, required:

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

[1] Regulatory Conditions imposed in the Merger Order require DEP and DEC each to pursue least-cost integrated resource planning and file separate IRPs until required or allowed to do otherwise by Commission order or until a combination of the utilities is approved by the Commission. The 2014 IRPs filed by DEP and DEC, and specifically the Joint Planning Scenario, appear to comply with this requirement.

In the Commission's May 7, 2013, Order Approving Rules, Requesting Comments, and Establishing Requirements for Electric Integrated Resource Plans to be Filed in 2014 in Docket No. M-100, Sub 135 (*Sub 135 Order*), the Commission detailed these natural gas issues:

- The potential risks inherent in their [the electric utilities'] increasing reliance on natural gas as a generation fuel and the long-term adequacy of North Carolina's gas infrastructure.
- The electric utilities' plans for procuring the additional gas supplies that would be required by the generation proposed in their IRPs.
- The electric utilities' plans to ensure long-term gas supply reliability and adequacy.
- The electric utilities' understanding of how much additional pipeline infrastructure will be needed, and when, due to the combined needs of gas distribution companies and existing and proposed gas-fueled electric generation.
- The advantages and disadvantages of a second major pipeline being built through North Carolina, and the electric utilities' understanding of the steps that would need to occur to effectuate such construction.

In its comments. the Public Staff concluded that DNCP, DEC, and DEP have made a reasonable assessment of their needs for natural gas infrastructure in order to meet their growing dependence on natural gas to provide electric generation. They also have demonstrated their understanding of how an interstate pipeline is planned, approved, and built, including the open season period to determine the market for the pipeline and associated costs. Additionally, the IOUs are knowledgeable about the natural gas supply market, as well as the pipeline planning and build-out in order to move the natural gas supply to their electric generation facilities. It appears that the Atlantic Coast Pipeline (ACP) will be the second major natural gas pipeline into the State of North Carolina. The utilities have adequately set out the benefits of this additional pipeline. The Public Staff recommends that the electric utilities and the natural gas distribution companies continue to work together in planning for adequate pipeline capacity to meet electric generation needs. The Public Staff also recommends that the electric utilities consider natural gas electric generation facilities that also can operate on an alternate fuel.

The Commission finds and concludes that DEC, DEP and DNCP have complied with all Rule R8-60 requirements in their respective 2014 IRPs. Each has provided acceptable 15-year peak and energy forecasts of native load and other firm loan requirements and obligations, as well as supply-side and demand-side resources expected to satisfy these loads. The reserve margins provided by the IOUs are reasonable for planning purposes and are approved.

Each IRP includes a full discussion of the utility's DSM programs and their use as required by Rule R8-60. DEC's Cliffside Unit 6 Carbon Neutrality Plan continues to show a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.

The Public Staff, in its comments submitted on March 2, 2015, provided 11 specific recommendations regarding the utilities' IRPs. They are discussed in the following section of this

Order. Several additional issues, raised by various other intervenors, along with responses by the utilities, appear later in this Order.

DISCUSSION AND CONCLUSION FOR FINDING OF FACT NO. 4

UTILITY RESPONSES TO SPECIFIC PUBLIC STAFF RECOMMENDATIONS REGARDING IRPS

1. In future IRPs, the utilities should include a discussion of the potential implications of the EPA Clean Power Plan, scenarios for possible compliance, and the costs of compliance.

DEC/DEP

Because the Clean Power Plan (CPP) Rule has not been finalized, and the rule is likely to undergo significant changes and clarifications considering the extent of comments filed with the EPA regarding the rule, it is difficult for the Companies to model what the exact impacts of the rule will have on the DEC and DEP IRPs. Answers to questions such as, "will the limits be rate or mass based?" and "which units will be included under the plan?" can have significant impacts on the IRP. For example, there is significant debate over the inclusion of carbon emissions from new natural gas combined cycle units. Given these uncertainties, the five scenarios presented in the DEC and DEP 2014 IRPs were evaluated with and without a carbon tax that coincided with the proposed onset of the CPP in 2020. A discussion of the impacts of the carbon tax on the initial resource needs, new nuclear selection, renewable generation, gas firing technology options, and energy efficiency was included in Appendix A of the IRP.

It must be noted that EPA's proposed CCP Rule is not a rule specific to a utility, but rather a state level rule requiring some form of CO_2 limits at the state level rather than the unit-specific or utility-specific level. Section lll(d) outlines the process by which a State Implementation Plan (SIP) would be developed by each of the states. Ultimately, the SIP will dictate the rules and procedures the state will mandate for each of the effected organizations that emit CO_2. The Companies respectfully submit that it is simply premature to include a proposed CPP compliance plan along with associated costs at this point in time.

DNCP

The Public Staff recognizes DNCP’s inclusion of Plan F: EPA GHG Plan for illustrative purposes in the 2014 Plan. Plan F was designed to illustrate a potential compliance scenario of how the Company could meet the proposed 2030 targets under the proposed Section 111(d) rule. The Public Staff commended DNCP for beginning to evaluate its CPP-compliance options, and recommends that the utilities’ future IRPs “include discussion of the potential implications of the [Section 111(d)] Rule, scenarios for possible compliance, and costs of compliance.”

The Company included the Plan F scenario in its 2014 Plan because it views planning for implementation of a final Section 111(d) rule as a prudent step given the proposed CPP rule’s complexities and timelines for compliance. The Company agrees with Public Staff that its future

IRPs should continue to plan for CPP compliance. During its 2015 Regular Session, the General Assembly of Virginia enacted Senate Bill 1349, which was signed into law by Governor McAuliffe on February 24, 2015. Senate Bill 1349 adjusts the Virginia resource planning process by 1) moving the 2015 IRP filing date to July 1 and requiring IRPs to be filed annually by May 1 beginning in 2016; 2) requiring future Virginia IRPs to address the effect of current and pending state and federal environmental regulations on existing generation facilities and new generation options; and 3) requiring future Virginia IRPs to evaluate the most cost-effective means of complying with state and federal environmental regulations, including options to minimize effects on customer rates. In recognition of the new resource planning obligations imposed by recently-enacted Senate Bill 1349, DNCP expects its future system-wide Plans to respond to the Public Staff's recommendation that future integrated resource planning address CPP compliance and the costs of compliance.

2. DEC should continue to review its forecasting models carefully, including planned changes to identify further improvements.

DEC/DEP

The Public Staff concluded that both DEC and DEP's load forecasts and methodologies were reasonable for planning purposes. The Public Staff nonetheless commented that its review of DEC's five-year peak load forecasting accuracy based upon the DEC forecasts for 2010-2014 filed in DEC's 2009 IRP indicates a forecast error of 5%. The Public Staff recommended that DEC continue to review its forecasting models carefully, including planned changes to identify further improvements. As it has discussed in recent previous IRP reply comments, and in discussions with the Public Staff, DEC's forecasting error rate in the 2008-2009 timeframe mostly resulted from the severe economic downturn that occurred in 2009 and which no one reasonably foresaw. DEC suffered more than DEP and most utilities in the 2009 recession due to its large amount of industrial load, particularly from textiles. In contrast, the DEC peak forecast developed in 2010 projected a 2013 value that was only 131 MW different than the actual weather adjusted value for the year 2013. Thus, DEC acknowledges the anomaly in the load forecast caused by the severe economic downturn, but appreciates the Public Staff's conclusion that the load forecast included in the 2014 IRP is reasonable. The Companies note that their forecasting methodology is always evolving in an effort to further improve the process, as a result of post-merger best practices and otherwise.

3. The companies should review their winter peak equations in order to better quantify the response of customers to abnormally low temperatures.

DEC/DEP

DEC stated that it certainly understands the importance of the long-term peak forecast's impact on future expansion plans. As such, DEC regularly reviews its peak forecasting methodology to ensure adherence to the latest industry standards. Given the increasing importance of efficiency trends on energy usage, DEC now incorporates Statistically Adjusted End Use Models (SAE) in its peak forecasting process. SAE models attempt to incorporate the effects of naturally occurring energy efficiency trends into the forecast as well as the expected impacts of government mandates. This approach also has the advantage of generating a forecast for each month rather than simply a seasonal forecast. In the Spring 2015 Forecast, the SAE methodology appeared to produce a slightly lower summer peak forecast, but a slightly higher winter peak forecast, which matches recent trends.

4. The companies should ensure that DSM resources identified in the IRP represent the reasonably expected load reductions available at the time the resource is called upon as capacity.

DEC/DEP

The Companies include expected summer DSM resources and reasonable corresponding load reductions in the IRP for planning purposes. Furthermore, DEC and DEP calculate expected DSM load reductions on a daily basis, known as the Load Reduction Capability (LRC), and are based on a rolling twelve weeks' worth of historical load data. These daily LRC calculations are utilized by the Companies' system operators in planning and operating the DEC and DEP systems. DEC and DEP utilize DSM programs in conjunction with system planning, not only for economic reasons. Daily system dynamics, including but not limited to weather, customer operational adjustments and interests, day of the week, and time of day, impact the load curtailment actually achieved and therefore will always vary from the summer DSM capacity contained in the IRP for planning purposes. It is important to note that DEC and DEP have contracts in place with customers to curtail their load pursuant to Commission-approved DSM programs, but beyond the monetary penalties that are provided for in the contracts, the Companies cannot control an individual customer's behavior in response to a request to curtail load.

DNCP

Specific to DNCP, the Public Staff asserted that DNCP's realized DSM capacity reductions were below the amount forecast in its 2014 Plan, with the Residential Air Conditioning Cycling program achieving 74% of its forecasted amount of capacity reductions, and the Customer Distributed Generation program achieving 65% and 71% of its forecasted winter and summer season capacity reductions, respectively. The Public Staff recommends that DSM resources identified in the IRP should "represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity" based upon enrolled DSM capacity and evaluation, measurement, and verification (EM&V) data. The Company is generally not opposed to this suggestion and incorporates actual performance and/or EM&V data into its planning process when appropriate and when the Company has sufficient program experience.

5. The Companies should put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands.

DEC/DEP

The Companies continually review potential new DSM programs and seek input on such programs as part of the EE stakeholder collaborative groups in place for both DEC and DEP.

DNCP

The Public Staff's comments highlight the recent winter system peak demands experienced by DNCP and the other utilities, and recommends the Company employ a "renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands." DNCP agrees with the Public Staff that its most recent experience during 2014 and 2015 suggests that renewed planning focus on peak demands experienced during the winter months may be warranted. During the "polar vortex" periods of January and February 2014, the PJM DOM LSE zone experienced a 16,834 MW system peak demand on January 7, 2014. Most recently, on February 21, 2015, at 8:00 a.m., DNCP experienced its all-time system peak of 18,687 MW, which is up from the 16,834 MW prior system peak experienced in 2014. Recognizing this recent winter peaking experience (and that the recent surge of proposed solar photovoltaic generation is of extremely limited capacity value during winter morning peaks), DNCP will evaluate DSM program options that provide reliable capacity to meet peak demands during both the winter and summer periods in future IRPs. Specifically, the Company continues to evaluate options for cost effective DSM programs that provide benefits during peak periods. The Company also notes that its Virginia commercial distributed generation program provides DSM capacity during both summer and winter periods, but was not approved for deployment in North Carolina.

6. The IOUs should consider the potential for relicensing of their existing nuclear units and reflect such potential relicensing in their IRPs.

DEC/DEP

The Companies plan to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of their customers they will pursue second license renewal (SLR) for our plants. At this point, no license extension for the operation of nuclear plants beyond 60 years has been issued.

The NRC has indicated that it plans to use the same process for SLR as it used during the initial license renewal; however, this only addresses the process to review the renewal application and not any additional requirements that the NRC may impose to extend the license from 60 years to 80 years. As for timing, the NRC does not plan to issue its guidance for requirements to extend the license from 60 years to 80 years until the 2017 to 2018 timeframe. The Companies do not anticipate the first SLR applications to be submitted until later this decade, with decisions on SLR not expected until approximately 2022 or 2023.

There is a significant amount of uncertainty regarding the ability to get a license extension as well as the uncertainty of the costs to satisfy NRC requirements should they extend the license. In addition to the uncertainty regarding SLR, there is also uncertainty regarding carbon regulations, environmental regulations, and fuel prices. DEC and DEP believe that the uncertainty combined with the new nuclear long development cycle(10 - 15 years to license and construct) makes it imperative that the Companies plan for these assets as if they will not be available, then adjust the plans as more information becomes available.

DNCP

As described in the 2014 Plan, the Company's customers today benefit substantially from the Company's prior investments in the four nuclear units, at North Anna and Surry, and the Company is mindful of the scheduled license expirations of these units between 2032 and 2040. The feasibility and cost of extending the lives and operating licenses of DNCP's existing nuclear units was similarly an issue of interest in the Company's recent Virginia IRP review proceeding. The State Corporation Commission of Virginia (VSCC) specifically directed DNCP to investigate the relicensing option for DNCP's existing nuclear units in its 2015 IRP filing, including comparing the cost of constructing North Anna 3 to the cost of renewing the licenses of the four existing nuclear units, as well as comparing the cost of retiring the four existing nuclear units to the cost of renewing the licenses for those units.

Accordingly, as the Company plans on a system-wide basis, the Company will provide an analysis of the potential for relicensing its existing nuclear units in its North Carolina IRP update to be filed by September 1, 2015.

7. Each utility should carefully review its projections of solar capacity.

DEC/DEP

In their 2014 IRPs, DEC and DEP assumed full NC REPS compliance, as well as compliance with a placeholder for a potential South Carolina renewable energy portfolio standard. The Companies include all currently signed solar, biomass and hydro contracts and any additional amounts required for full compliance in the later years. Solar providers are rushing to take advantage of the Federal and State tax incentives before their current expiration dates, and as such continue to submit their projects to the interconnection queue. DEC and DEP recently filed their Small Generator Interconnection Consolidated Annual Reports in Docket No. E-100, Sub 113B, which indicate that the projects currently in the interconnection queues for DEC and DEP total over 4,000 MW (nameplate) in both service territories. The vast majority of these projects are solar. Even though there is such a large amount of solar in the queue, the likelihood of these projects coming to fruition is unknown. Typically, only a fraction of these projects actually begin operation. As projects come online, the Companies will continue to sign contracts to ensure full compliance with NC REPS as well as those projects without associated RECs that will not be used for NC REPS compliance, but are qualifying facilities (QFs) under PURPA. The Companies also include the non-compliance renewable projects in the IRP as part of the purchase contracts.

The Companies will continue to monitor the interconnection queue and sign contracts as the facilities actually begin operation.

DNCP

The Company is not opposed to reviewing its solar PV QF projections, similar to all other projections, in developing future Plans. However, as discussed at length in the Commission's recent avoided cost proceeding, Docket No. E-100, Sub 140, the Company's current experience does not support relying on the Company's interconnection queue to determine the solar QF resource capacity that may become commercially operational.

The Company's experience during the recent solar PV QF development surge has been that numerous projects in its interconnection queue are "speculative" and have a low probability of development and commercial operation as a resource that DNCP can rely upon to serve customers. Even where a QF has applied for interconnection, has filed for and obtained a CPCN, and executed a power purchase agreement (PPA), the Company still has little assurance of when or if the facility will be made operational. There are numerous aspects of a typical solar PV development project that will dictate whether it is ultimately constructed, including interconnection costs and constraints, qualification for and monetization of tax credits, securing financing, cost of equipment and construction, and, potentially, finding a buyer for the project. Because the Company has little to no visibility into these variables and little meaningful historical data to assess the percentage of solar QF capacity likely to be deployed, DNCP does not believe it prudent to rely upon the level of solar QF capacity pending in its interconnection queue as a reliable metric for future solar QF deployment in its service territory. In summary, so long as QF developers are not required to make any construction commitments when filing a CPCN or executing a PPA, the Company has very little ability to make meaningful estimates on the volume or timing of such QF development. Therefore, for planning purposes, the Company is limited to using its best estimate about the volume and timing of the QF projects that will ultimately be constructed. As in previous IRPs, the Company will continue to review CPCN filings and PPA status each year at the time of the IRP development and incorporate its best estimate of future QF development.

8. DEP, DEC, and DNCP should maintain their proposed reserve margins as filed.

DEC/DEP

The Companies plan to review their reserve margins in 2015, in response to the recent winter peak loads experienced and the interconnection of increasing amounts of intermittent renewable resources to the DEC and DEP systems. Pending the results of that study, the Companies may seek to update their required minimum planning reserve margin target.

DNCP

DNCP agrees with the Public Staff's recommendation.

9. For future IRPs that foresee substantial nuclear retirements, the planning period, and in particular, the period covered by the Load, Capacity, and Reserve Tables should be extended to 20 years.

DEC/DEP

The Companies believe that the current 15-year planning horizon provides the most reasonable outlook for new generation requirements. Extending the required reported planning horizon to twenty years would add an additional level of uncertainty to the IRP reports, as the further out generation is evaluated, the inherently more uncertain the basis for those additions becomes. Additionally, 10 to 15 years matches the time required for licensing and constructing the longest lead time generation the Companies evaluate. Extending the planning period beyond 15 years would add an unnecessary administrative burden to the planning process, particularly in light of the fact that successive plans will certainly change over that additional timeframe. As such, DEC and DEP respectfully submit that having extensive stakeholder debate over planned resources projected for years 16 through 20 would only serve to complicate the annual IRP process while adding little tangible value to the process.

DNCP

DNCP believes that the Public Staff's specific recommendation "for future IRPs that foresee substantial nuclear retirements, the planning period, and in particular, the period covered by the Load, Capacity, and Reserve Tables should be extended to 20 years" is unnecessary. In the 2013 IRP proceeding, the Company opposed extending its planning period beyond the 15-year period required by Commission Rule R8-60(c) and (h), as well as Va. Code 56-592 *et seq.* and the VSCC's Integrated Resource Planning Guidelines. The 2013 IRP Order stated that the Commission is "satisfied with [the Utilities'] current 15-year planning periods," but that the Utilities "should always supply additional forward looking comments in their IRPs when warranted to provide adequate background concerning critical infrastructure decision-making." Accordingly, DNCP requests the Commission find that its proposal to provide an analysis of the potential for relicensing its existing nuclear units in its 2015 IRP update is adequate and that there is no need to extend the 15-year planning period at this time.

10. The utilities should continue to develop methods of quantifying the benefits of fuel diversity.

DEC/DEP

As discussed in the Companies' 2013 IRP Update Reply Comments, the Companies believe that this recommendation is already captured as part of the existing IRP process commensurate with Commission Rule R8-60. The Companies' current IRP practices include modeling multiple sensitivities around fuel prices. Furthermore, the Companies show how different resource portfolios perform under these varying fuel prices. Both the quantitative impacts and the qualitative benefits of fuel diversity are fully presented in the IRPs. The Public Staff does not provide a specific recommendation as to what other quantitative metric or method they are recommending and as such it is difficult to ascertain the merits of such additional analysis. The Companies believe that the current approach both quantitatively and qualitatively addresses fuel diversity and is fully adequate.

DNCP

At the outset, the Company would note that its 2014 Plan does not select its Fuel Diversity Plan over the least-cost Base Plan. Instead, the Company recommends a path forward based upon the least-cost Base Plan, while concurrently continuing forward with reasonable development efforts of the additional resources identified in the Fuel Diversity Plan. As with any strategic plan, the Company will update its future Plans to incorporate new information as it becomes known.

In response to the Public Staff's Recommendation in the 2013 IRP proceeding, E-100, Sub 137, to establish metrics to quantify the benefits of fuel diversity, the Company's 2014 Plan provides the Section 6.6 "Portfolio Evaluation Scorecard" framework. The Scorecard is designed to evaluate the Base Plan relative to other alternative Plan scenarios based upon the following criteria: Strategist NPV cost results to reflect the least cost option; Rate Stability; fuel and construction cost risk, GHG Emissions, and Fuel Supply Concentration. Figure 6.6.1.1 in the 2014 Plan presents the analysis and criteria scoring under the Scorecard framework, while Figure 6.6.1.2 shows the Scorecard rankings for each planning scenario. The Fuel Diversity and EPA GHG Plans received the most favorable scores on the Scorecard. The results of the 2014 Plan's Scorecard framework supports the Company's planning recommendation to continue following the least-cost Base Plan, while also continuing reasonable development of the Company's Fuel Diversity Plan.

Further, the VSCC's 2013 Virginia IRP Order also requires the Company to "include an analysis of the trade-off between operating cost risk and project development cost risk associated with the Base Plan and the Fuel Diversity Plan" starting in the 2015 Virginia IRP filing. The Company plans to include a probabilistic analysis in the 2015 IRP which will provide a comparative assessment of operating cost risk and project development cost risk for both the Base Plan and the Fuel Diversity Plan. This analysis will further address the value of fuel diversity.

11. The utilities should provide not only the PVRR for the possible resource expansion plans, but also an estimate of the annual rate impacts of such plans levelized over the life of the resource additions.

<u>DEC/DEP</u>

The Companies do not believe that providing an estimate of annual rate impacts of proposed resource plans in future IRPs is warranted. First, the Public Staff's recommendation is not part of the statutory requirement of the IRP filing to assist the Commission in fulfilling its responsibility pursuant to G.S. 62-110.1(c) to "develop, publicize, and keep current an analysis of the long-rage needs" for electricity in the State. The Commission has repeatedly held that its approval of an IRP does not constitute approval of any of the individual generation resources contained therein, but that such individual generation resources are considered separately as part of the Certificate of Public Convenience and Necessity (CPCN) process established by G.S. 62-110.1 and Commission Rule R8-61. The Companies respectfully submit that consideration of rate impacts would be beneficial only after a utility has actually decided to construct a given generation plant. It is in a specific CPCN docket, or in a subsequent cost recovery proceeding, therefore, and not in an IRP docket, where rate impacts are appropriately considered. Indeed, Commission Rule R8-61(b)(3)(viii), which became effective January 1, 2015, now requires the filing of "the anticipated impact the facility will have on customer rates" as part of a utility's CPCN application.

Second, each IRP filing represents a "snapshot in time" view of the Companies' preferred resource plans over the 15-year planning horizon. The myriad inputs to the IRP planning process, including but not limited to cost assumptions, load forecasts, expected plant retirements, wholesale contracts, and evolving regulatory requirements necessarily change annually (if not multiple times within a year), as do the selected resource plans and the timing, size and nature of individual supply and demand side resources included within the resource plans. As a result, even if developed for the IRP filing, such annual rate impacts would be of limited value. Third, calculating such annual rate impacts would be an extremely burdensome and time-consuming effort for the Companies. The Companies' IRP planning process is already a year-round endeavor, and adding the annual rate impact estimation as part of the IRP would only add complexity and burden to the process, for limited, if any, benefit.

DNCP

While an estimate of annual rate impacts of resource additions on a levelized per kWh basis may provide some understanding of ratepayer impacts, the Company believes this value would be limited in comparison to the way bill impacts are provided in base rate, fuel, DSM and other ratemaking proceedings. In addition, the Company is concerned that such an additional requirement may be a source of confusion for customers since the Company is not asking for actual cost recovery in the IRP proceeding. Finally, DNCP notes that the Commission did not agree to this recommendation in the 2013 IRP Order.

In sum, while the Company disagrees with the Public Staff's specific recommendations to present PVRR and annual rate impacts of each planning scenario in analyzing its future Plans, the Company through its Portfolio Evaluation Scorecard framework provides a reasonable approach to quantifying the benefits of fuel diversity in its 2014 Plan and will continue to present the results of this analysis in future Plans.

The Commission has reviewed the responses that were provided by DEC, DEP and DNCP to the eleven specific issues raised by the Public Staff. Those responses appear appropriate and adequate to the issues raised. Based on those answers provided in the IOUs' reply comments, the Commission does not find it necessary to require DEC, DEP and DNCP to make any additional changes to their future IRP filings at the present time, other than those discussed in their individual reply comments.

DISCUSSION AND CONCLUSION FOR FINDING OF FACT NO. 5

REPS COMPLIANCE PLAN REVIEW

G.S. 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and EE through the REPS. One MWh of renewable energy, or its thermal equivalent, equates to one renewable energy certificate (REC), which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction (or through DSM measures, in the case of electric membership corporations (EMCs) and municipalities). The electric public utilities (DEP, DEC, and DNCP) may use EE measures to meet up to 25% of the general requirements in G.S. 62-133.8(b). One MWh of savings from DSM, EE, or demand reduction creates one energy efficiency certificate (EEC), which is similar to a REC and is used to demonstrate compliance with the REPS. EMCs and municipalities may use DSM and EE to meet the requirements in G.S. 62-133.8(c) without any limits. They may also purchase electric energy from a hydroelectric power facility and use allocations from SEPA to meet up to

30% of the overall requirements. All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of the requirements of G.S. 62-133.8(b) and (c), with the exception of DNCP, which can use out-of-state RECs to meet 100% of the requirements. The total amount of renewable energy or EECs that must be provided by an electric power supplier for the year 2014 is equal to 3% of its North Carolina retail sales for the preceding year. For 2015 and 2016, this amount is 6%.

Commission Rule R8-67(b) provides the requirements for REPS compliance plans (Plans). Electric public utilities must file their Plans on or before September 1 of each year, as part of their IRPs, and explain how they will meet the requirements of G.S. 62-133.8(b), (c), (d), (e), and (f). The Plans must cover the current year and the next two calendar years, or in this case 2014, 2015, and 2016 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5). The instant docket includes the plans filed by DEP, DEC, and DNCP, which includes plans for their wholesale customers in North Carolina for which they have contracted to provide REPS compliance services.

All three IOUs filed their 2014 Plans as part of their IRP. Immediately below are the Public Staff's comments on DEP, DEC, and DNCP's plans to comply with G.S. 62-133.8(b), (c), and (d), the general and solar energy requirements, followed by consolidated comments on plans to comply with G.S. 62-133.8(e) and (f), the swine waste and poultry waste resource requirements.

DEP

According to the Public Staff, DEP has contracted for and banked sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for itself and the electric power suppliers for which it is providing REPS compliance services. DEP is contractually obligated to secure resources to meet all the REPS requirements of the City of Waynesville and the Towns of Sharpsburg, Stantonsburg, Black Creek, Lucama, and Winterville (collectively, DEP's Wholesale Customers).

DEP intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities and energy allocations from SEPA will be used to meet up to 30% of the general requirement of the City of Waynesville, the only DEP Wholesale Customer that receives energy from SEPA. Hydroelectric QFs with a capacity of 10 MW or less will also provide RECs for DEP's retail customers. DEP will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement of DEP and its Wholesale Customers will be met by executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are combined heat and power facilities. DEP also plans to use the increased availability of solar energy to help it meet the general requirement.

To meet the solar requirement, DEP will obtain RECs from its residential solar PV program and from other solar PV and solar thermal facilities.

DEP anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEP files its EM&V plan for each EE program as part of its request for Commission approval of the program.

DEC

The Public Staff noted that DEC has contracted for or procured sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the planning period, both for itself and for the electric power suppliers for which it is providing REPS compliance services. DEC is contractually obligated to secure resources to meet all the REPS requirements of the following electric power suppliers: Rutherford EMC, Blue Ridge EMC, the City of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, DEC's Wholesale Customers).

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities and energy allocations from SEPA will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers. Hydroelectric qualifying facilities of 10 MW or less, together with the increased capacity of DEC's Bridgewater hydroelectric facility following its modification in 2012, will provide RECs toward DEC's REPS obligation. DEC will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement of DEC and its Wholesale Customers will be met by executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are combined heat and power facilities. However, DEC has reduced its reliance on biomass for future REPS compliance because of the increased availability of solar energy and other renewable resources. DEC expects to use solar resources to satisfy some of its REPS requirement.

To meet the solar requirement, DEC will obtain RECs from its self-owned distributed solar PV facilities and from other solar PV and solar thermal facilities.

DEC anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEC filed an update to its EM&V plan in its 2014 application for cost recovery of DSM and EE programs in Docket No. E-7, Sub 1050.

DNCP

The Public Staff stated that DNCP has contracted for and banked sufficient RECs to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the planning period for itself and the Town of Windsor (Windsor), for which it is providing REPS compliance services. DNCP plans to use EE, purchased out-of-state wind RECs, and new self-generated renewable energy to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself. For Windsor's general REPS requirement, DNCP plans to use out-of-state wind RECs, in-state biomass and solar

RECs, and Windsor's SEPA allocation. For the solar requirements, DNCP plans to purchase in-state and out-of-state solar RECs for itself and Windsor. DNCP will rely on out-of-state RECs to meet most of its compliance requirements, as allowed by G.S. 62-133.8(b)(2)(e), but will obtain in-state RECs to meet Windsor's 75% in-state requirement.

DNCP anticipates that it will incur relatively high research and development costs in 2014 and 2015 for its Microgrid Project, but these costs should be minimal in 2016. The Microgrid Project consists of wind and solar energy generation and storage at DNCP's Kitty Hawk District Office with fuel cells possibly added in 2015. The high costs in 2014 and 2015 are due to construction costs. DNCP anticipates that the REPS compliance costs for itself and Windsor will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DNCP filed an update to its EM&V plan in its 2014 application for cost recovery of DSM and EE programs in Docket No. E-22, Sub 513.

REPS COMPLIANCE COMPARISON TABLES

The Public Staff prepared the tables in this section from data submitted in the DEP, DEC, and DNCP Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year; for instance, the sales in the 2014 column are projected sales for calendar year 2013. The totals are presented in this manner because each utility's REPS obligation is determined as a percentage of its MWh sales for the preceding year.

The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services.

TABLE 1: MWh Sales for preceding year

	Compliance Year		
Electric Power Supplier	**2014**	**2015**	**2016**
DEP	36,091,870	38,431,441	38,894,821
DEC	58,813,405	60,013,663	60,658,787
DNCP	4,358,551	4,186,914	4,256,454
TOTAL	99,263,826	102,632,018	103,809,062

Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps, which increase significantly in 2015 due to the residential cost cap increasing from $12 per year to $34 per year.

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEP	DEC	DNCP
2014	Incremental Costs	23,630,618	17,768,556	1,103,132
	Cost Cap	43,915,738	63,070,639	4,017,364
	Percent of Cap	54%	28%	27%
2015	Incremental Costs	22,106,981	20,805,290	1,432,489
	Cost Cap	71,350,928	103,084,760	6,246,082
	Percent of Cap	31%	20%	23%
2016	Incremental Costs	28,043,011	24,822,911	1,484,093
	Cost Cap	72,044,678	104,218,833	6,239,114
	Percent of Cap	39%	24%	24%

SWINE WASTE AND POULTRY WASTE REQUIREMENTS IN G.S. 62-133.8(E) AND (F)

In its comments, the Public Staff stated that some electric power suppliers indicated in their Plans filed in 2011 that they were having difficulty in obtaining RECs to comply with the swine and poultry waste requirements in G.S. 62-133.8(e) and (f), which required them, beginning in 2012, to meet a portion of their REPS obligations with energy derived from swine waste and poultry waste.

In May 2012, the Commission issued an order in Docket No. E-100, Sub 113, requiring the electric power suppliers to file an update on their efforts to meet these compliance requirements. Most electric power suppliers responded by filing a joint motion seeking to delay the swine and poultry waste requirements as allowed in G.S. 62-133.8(i)(2). The joint movants claimed that they had had difficulty acquiring RECs to meet the swine and poultry waste requirements because the technology for animal waste-to-energy facilities was still in its infancy and would need more time to reach maturity.

In November 2012, the Commission issued an order that eliminated the swine waste set-aside for 2012 and delayed the poultry waste set-aside until 2013. This order required DEP and DEC to file tri-annual reports describing the state of their compliance with the set-asides and reporting on their negotiations with the developers of swine and poultry waste-to-energy projects. The Order further required them to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities.

On September 16, 2013, many of the electric power suppliers filed another joint motion to delay the swine and poultry waste set-asides, similar to the request they filed in 2012. In this proceeding, the Commission issued a Notice of Decision and Order on December 20, 2013, that delayed the swine and poultry waste set-asides until 2014. The Order extended the tri-annual reporting to DNCP and most other EMCs and municipal electric systems. It also requested that the Public Staff hold stakeholder meetings in 2014 and 2015 to facilitate compliance with the swine and poultry waste requirements. The Commission issued a final Order on March 26, 2014.

On August 28, 2014, many of the electric power suppliers filed a joint request to delay the swine waste requirement for one more year, and the Commission granted the request in an Order dated November 13, 2014. The electric power suppliers did not request to delay the poultry waste requirement, and the Public Staff believes that 2014 will be the first year that the electric power suppliers will be able to comply with this requirement as modified by the Commission. One reason that the electric power suppliers did not request a delay in the poultry waste requirement is the relatively low requirement of 170,000 MWh or equivalent energy in 2014 and the utilities' ability to bank RECs from earlier years. In addition, the availability of poultry waste RECs in the marketplace has been increased due to advances in the technology of power generation from poultry waste, and by the use of thermal energy to meet the requirement as authorized by N.C. Session Law 2011-309, and by the availability of poultry waste RECs from "cleanfields renewable energy demonstration parks," as authorized by N.C. Session Law 2010-195.

On June 23 and December 3, 2014, the Public Staff held stakeholder meetings as requested by the Commission. The attendees included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, state environmental regulators, and the electric power suppliers. The Public Staff believes that the meetings were made productive by allowing the stakeholders to network and voice their concerns to the other parties. The Public Staff intends to hold two more meetings in 2015 as requested and believes that they will be useful. However, the Public Staff believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste requirements for at least the next two years. The poultry waste requirement will more than quadruple from 170,000 to 700,000 MWh in 2015 and rise to 900,000 MWh in 2016. No electric power supplier requested a delay in the poultry waste set-aside for 2014, but both DEP and DEC have stated that they are "uncertain" that they can meet the poultry waste requirement in 2015 and beyond. The Public Staff agrees that the capacity of poultry waste-to-energy facilities may not be sufficient to generate enough RECs for 2015, and possibly not 2016. DNCP is in a better position because it can obtain all of its RECs from out of state.

The swine waste-to-energy industry has a few facilities operating in North Carolina, but its generation is very small relative to the need for approximately 70,000 MWh of in-state swine waste energy per year to meet the Commission's Order of November 13, 2014. Swine waste-to-energy facilities cannot earn RECs from thermal energy as poultry facilities can; however, they would probably be limited in thermal capacity even if thermal energy were allowed to earn RECs for several reasons, including differences in the energy content of each fuel on a volumetric basis and technological differences between the waste-to-energy facilities utilizing each fuel type.

The lack of swine and poultry waste-to-energy facilities is the result of: (1) limited technology development and expertise because currently North Carolina is the only state with swine and poultry waste requirements; (2) the utilities' reluctance to commit to expensive purchase contracts for speculative technologies; (3) limited availability of financing; and (4) uncertainty over REC prices.

PUBLIC STAFF'S CONCLUSIONS ON REPS COMPLIANCE PLANS

In summary, the Public Staff's conclusions regarding the REPS compliance plans of DEP, DEC, and DNCP are as follows:

1. The compliance plans of DEP, DEC, and DNCP indicate that they should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste requirements, without nearing or exceeding their cost caps.

2. DEP, DEC, and DNCP will have difficulty meeting the Commission's revised swine waste requirements in 2015 and 2016, and DEP and DEC will have difficulty meeting the poultry waste requirements. However, they are actively seeking energy and RECs to meet these requirements.

3. The Commission should approve the REPS compliance plans filed by DEP, DEC, and DNCP in 2014.

The preceding pages provide the Public Staff's utility-by-utility review of the REPS compliance plans submitted by the IOUs. Based on the Public Staff's review, it provided its conclusions on these plans as shown above and recommends that the Commission approve the REPS compliance plans filed by DEP, DEC and DNCP in 2014. The Commission concurs with this recommendation and therefore approves the REPS compliance plans submitted by the utilities with their 2014 IRPs.

DISCUSSION AND CONCLUSION FOR FINDING OF FACT NO. 6

ADDITIONAL ISSUES RAISED IN INTERVENOR COMMENTS

NCSEA

Energy Storage

In its initial comments, NCSEA requested that the Commission amend Rule R8-60(e) to include utility-scale energy storage as an alternative supply-side energy resource. NCSEA further requested that the Commission amend Rule R8-60(i)(10) to focus on smaller-scale energy storage. NCSEA proposed the following amendment to Rule R8-60(e):

> Alternative Supply-Side Energy Resources. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of reasonably available alternative supply-side energy resource options. Alternative supply-side energy resources include, but are not limited to, hydro, wind, geothermal, solar thermal, solar photovoltaic, municipal solid waste, fuel cells, ~~and biomass~~. biomass, and utility-scale energy storage.

NCSEA likewise proposed the following amendment to Rule R8-60(i)(10):

> Smart Grid Impacts. -Each utility shall provide information regarding the impacts of its smart grid deployment plan on the overall IRP.
>
> For purposes of this requirement, the term "smart" in smart grid shall be understood to mean, but is not limited to, a system having the ability to receive, process, and send information and/or data - essentially establishing a two-way communication protocol.
>
> For purposes of this requirement, smart grid technologies that are implemented in a smart grid deployment plan may include those that: (1) utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility's distribution or transmission system; (2) optimize grid operations dynamically; (3) improve the operational integration of distributed and/or intermittent generation sources, <u>small-scale</u> energy storage, demand response, demand- side resources and energy efficiency; (4) provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; and/or (5) provide customers with usage information.
>
> The information provided shall include:
>
> (a) A description of the technology installed and for which installation is scheduled to begin in the next five years and the resulting and projected net impacts from installation of that technology, including, if applicable, the potential demand (MW) and energy (MWh) savings resulting from the described technology.
> (b) A comparison to "gross" MW and MWh without installation of the described smart grid technology.
> (c) A description of MW and MWh impacts on a system, North Carolina retail jurisdictional and North Carolina retail customer class basis, including proposed plans for measurement and verification of customer impacts or actual measurement and verification of customer impacts.

NCSEA requested that the Commission direct the utilities to use the best available model to consider energy storage during the IRP process. Because of the current lack of models that best integrate energy storage, at this time the directive would mean that the utilities use their current best practices and existing models. When more appropriate models become available, they should be used by the utilities for future IRPs.

In their joint reply comments, DEC and DEP responded that NCSEA does not appear to have any criticism of the DEC and DEP IRPs, but instead asks the Commission to amend Rule RS-60(e) to include utility-scale energy storage as an alternative supply-side energy resource and amend Rule R8-60(i)(10) to list small-scale energy storage as a smart grid technology.[1] While the benefits of advanced energy storage are obvious, the costs and practical applications of energy storage on a macro-level are less known. As the costs of this technology decline and impacts of energy storage on the grid come into clearer focus in the coming years, it may be a beneficial addition to the Companies' IRPs, but until then, it would not be prudent to include these systems. The Companies continue to monitor advanced energy storage technologies and evaluate potential uses in the Carolinas. However, at this time these technologies are neither economical, nor viable on a macro level for use in the IRP. The Companies will include Li-ion battery storage technology in the economic supply- side screening process as part of the 2015 IRP.

In its reply comments, DNCP explained that it does, in fact, evaluate energy storage in its 2014 Plan (as recognized by NCSEA's comments), finding that while "batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar on the grid the primary challenge facing battery systems is the cost."[2] The Company plans to continue to evaluating energy storage options in future IRPs. However, DNCP does not view NCSEA's anecdotal support for the expected maturation of energy storage to a least-cost resource as trumping reality. Further, as NCSEA concedes, models do not currently exist today to fully evaluate the costs and benefits of energy storage. Therefore, DNCP questions the utility of recommending that the utilities be required to "take their best shot" at modeling energy storage. Instead, energy storage should continue to be evaluated under R8-60(i)(10), as a smart grid resource that can be integrated – if cost effective – to "improve the operational integration of distributed and/or intermittent generation sources." Finally, DNCP objects to NCSEA's procedural approach, which it characterizes as "lobbing its proposed revision to Rule R8-60(e) into this IRP review proceeding." DNCP states that NCSEA's request blurs the purpose of this proceeding, as established by the Commission's September 29, 2014, Order Establishing Dates for Comments on Integrated Resource Plans, REPS Compliance Plans and REPS Compliance Reports. According to DCNP, in past proceedings, both the Company and NCSEA have taken the procedurally-more-appropriate tact of foreshadowing a future request to modify a rule in a separate proceeding or requesting the Commission to initiate a rulemaking and NCSEA should have taken that tact here also. In sum, while DNCP submits there is little merit to NCSEA's recommendation to modify Rule R8-60(e), it argues the more appropriate place to consider such a request (if the Commission is inclined to do so) would be a separate rulemaking proceeding.

The Commission agrees with DEC, DEP and DNCP that these technologies are not economical or viable at this time for mandatory inclusion in the utilities' IRPs. Further, as models do not currently exist for a proper evaluation of energy storage, the Commission does not see a benefit in simply asking the IOUs to take their best shot at a modeling approach at this time.

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[1] NCSEA spends approximately half of its Initial Comments field March 2, 2015, summarizing the DEC and DEP IRPs. The Companies note that NCSEA's Figures 2 and 3 at pp. 15-16 of its Comments omit the Companies' generation facilities located in South Carolina, which also serve the Companies' North Carolina customers.

[2] 2014 Plan, at 62-63.

MAREC

Wind Energy

According to MAREC in its comments, wind energy costs have fallen by 58% over the past five years, and wind energy represents an increasingly competitive form of energy. However, DEC's and DEP's IRPs project very little use of wind energy throughout the planning period.

MAREC recommends that the Commission direct DEP and DEC to revise their IRPs to include additional consideration of cost-effective wind resources in order to provide additional resource diversity both for meeting REPS requirements and in preparation for EPA's Clean Power Plan compliance. MAREC pointed out that, in its order approving DEC's and DEP's 2012 IRPs, the Commission held that the two companies "should continue to assess alternative-supply side resources such as wind energy on an ongoing basis." The Commission further ordered that the utilities "should consider additional resource scenarios that include larger amounts of renewable energy resources and to the extent those scenarios are not selected, discuss why the scenario was not selected."

MAREC concluded its comments with the following recommendations:

- The Commission should direct DEC and DEP to continue to evaluate the market price of all renewable energy resources for REPS compliance, including seeking additional renewable energy diversity when prices of various resources are comparable.
- Given the downward trend in wind energy costs, the Commission should direct DEC and DEP to continually seek feedback from the market on current wind energy prices and evaluate wind energy competitiveness not just for REPS compliance, but for competition with conventional generation resources.
- The Commission should direct DEC and DEP to include wind energy pricing in future cost sensitivity analyses.
- In light of DEC's and DEP's expectation for carbon dioxide legislation and the pending finalization of the Clean Power Plan, the Commission should direct that DEC's and DEP's generation screening alternatives continually evaluate whether renewable energy, energy efficiency and renewable energy/gas hybrid scenarios are a cost effective means to meet CPP goals.

In their joint reply comments, DEC and DEP responded that DEC's 2014 IRP base case includes 860 MW of renewable resources by 2019 and 2,155 MW by 2029, which includes 150 MW of wind. DEP's 2014 IRP base case includes 907 MW of renewable resources by 2019 and 1,187 MW by 2029, which includes 100 MW of wind. DEC and DEP explained that MAREC does not appear to appreciate, however, that both Companies' 2014 IRPs also included a High EE and High Renewables portfolio, which evaluated an assumed requirement to serve approximately 10% of each Company's combined retail load with new renewable resources by 2029—which represents over twice the amount of renewable energy as compared to the base case. The DEC High EE/Renewables portfolio included 427 MW of nameplate wind and the DEP High EE/Renewables included 289 MW of nameplate wind. The purpose of the scenario is to show how the Companies' resource plans would be affected in the event that additional cost-effective renewable and energy efficiency resources are identified or mandated. A key takeaway is that, in such an event, some traditional resources can be eliminated or deferred but significant levels of traditional resources such as new nuclear and natural-gas combined cycle are still needed.

According to DEC and DEP, the main locations for wind energy generation in the Carolinas are the North Carolina mountains and on-shore coastal regions. With ridge laws prohibiting wind turbine construction in the North Carolina mountains and siting issues along the coast, there are real physical limitations to the amount of wind power that could be built in the Carolinas currently. DEC and DEP, collectively, only have one wind project in the interconnection queue: a very small project of only approximately 2.5 kW. While the National Renewable Energy Laboratory study cited by MAREC may have determined a large potential for North Carolina wind projects, the prohibitive laws and siting issues continue to hinder wind facility construction in the North Carolina mountains or coast.

DEC and DEP believe that they have adequately considered wind and all other potential renewable energy resources in preparing their 2014 IRPs. They state that Duke Energy Corporation, the parent company of DEC and DEP, is one of the largest wind energy developers in the United States and recognizes the valuable potential that new wind energy resource development can provide. In their IRPs, however, DEC and DEP analyzed wind and other generation technologies and selected the resource plans that best met the Companies' needs to provide the reliable, least-cost resource mix as required by North Carolina's integrated resource planning and REPS laws. DEC and DEP noted that, it is for these reasons, that they Companies maintain a reasonable total of 250 MW of wind resources in their plans.

The Commission finds that DEC and DEP have adequately responded to the issues raised by MAREC related to wind energy. No further action is necessary at this time.

<u>SACE and Sierra Club</u>

<u>Renewables, Energy Efficiency and Environmental Compliance Costs</u>

The initial comments of SACE and the Sierra Club stated that the 2014 IRPs of DEC and DEP contain limited improvements upon the Companies' previous IRPs, but unfortunately, retain most of the flaws of earlier IRPs. In addition, new assumptions and methods compound the flaws carried over from previous plans, resulting in resource plans that are more costly, more risky, and more polluting than necessary. Key flaws in the 2014 IRPs include the following:

- The Companies are planning to build too much capacity, while underinvesting in resources that would reduce system costs for all customers.
- The Companies do not appear to have evaluated the full range of costs to achieve and maintain compliance with environmental regulations at their coal-fired power plants. For some units, accelerated retirement may be the most economic option.
- As in prior IRPs, the Companies are not planning to capture all cost-effective energy efficiency, the cheapest, cleanest resource. This means system costs for ratepayers will be significantly higher than they need to be.
- The Companies do not plan to maximize cost-effective renewable energy opportunities

that reduce risks to customers from rising fuel costs and anticipated regulatory requirements.

SACE and the Sierra Club asserted that, as discussed in comments on previous IRPs, the Companies use inconsistent criteria to evaluate the risks associated with each resource, using criteria that provide support for favored resources while applying different criteria or analytic methods to undervalue energy efficiency and renewable energy. The concerns raised in prior comments with respect to the Companies' inconsistent consideration of risk are only magnified in the 2014 IRPs. The ever-changing criteria for evaluation seem to track the changing economics of DEC's proposed Lee nuclear plant.

SACE and the Sierra Club maintained that the DEC and DEP 2014 IRPs resulted in the selection of preferred resource portfolios that, if implemented by the Companies, would be unnecessarily costly, risky, and polluting. To correct these flaws and minimize costs and risks to ratepayers and the environment, they recommended that the Commission issue an order directing the Companies to implement the following improvements, which are set forth in greater detail in the various sections of SACE and the Sierra Club's initial comments.

- Evaluate the costs to ratepayers of various resources over both the short- and long term, to accurately assess their risks and benefits;
- Clearly disclose the results of any analyses of changes to coal unit operations necessary to comply with forthcoming air, water and waste regulations;
- Plan to achieve the energy efficiency savings targets agreed to in connection with the Duke Energy-Progress Energy merger, and evaluate energy efficiency as a resource that competes on its own merits with supply-side resources and can grow over the planning horizon;
- Explicitly recognize and incorporate the benefits that renewable energy resources provide in addition to capacity and energy, including hedging against fuel cost and environmental compliance cost risks; and
- Study best practices for modeling utility-scale and distributed solar technologies and integrating such analysis into resource plans, and incorporate those practices into development of future IRPs.

In their joint reply comments, DEC and DEP observed that SACE and Sierra Club note that DEC "led the Southeast in energy savings from efficiency," in both 2011 and 2012, and that DEC ranked 2nd in the Southeast in 2013 and DEP ranked 3rd in the Southeast in 2013 in efficiency savings as a percentage of retail sales. Yet, despite these accolades, as in previous IRP comments, SACE and Sierra Club allege that DEC and DEP are not planning to capture all cost-effective EE and maximize renewable energy opportunities. DEC and DEP maintain that they have, however, included significant levels of EE and renewable resources in their 2014 IRPs, as detailed in Appendix D to the DEC and DEP 2014 IRPs.

DEC and DEP stated that on page 6 of the SACE Comments, SACE and Sierra Club state that "DEC's projection of EE impacts peaks in 2025 . . ." and that "DEP's projection of EE impacts peaks around 2021 ...;" however, these statements are incorrect. The Companies' EE forecasts do not peak as claimed, but continue to grow on a cumulative basis until reaching the full achievable market potential as estimated in the Forefront Economics market potential studies previously provided in this and other IRP dockets.

DEC and DEP argued that, contrary to SACE and Sierra Club's arguments, it would be imprudent for the Companies to include projected impacts from EE beyond the levels estimated in the market potential studies. Furthermore, SACE and Sierra Club leave the false impression that the Companies have excluded consideration of EE from its planning process for half of the PVRR study period. This is not correct because the cumulative projected impacts that capture the estimated market potential have been incorporated into the IRP analysis. The EE savings impacts have not been "terminat[ed]" ... "halfway through the planning horizon" as alleged by SACE and Sierra Club; rather, all EE impacts that are reasonably expected to be achievable have been captured in the overall IRP process.

DEC and DEP further argued that SACE and Sierra Club also ignore the fact that both DEC and DEP evaluated two portfolios with High EE targets in their 2014 IRPs. These aspirational EE portfolios averaged $5 billion higher cost than the base portfolio on a PVRR basis. Thus, while the Companies appropriately accounted for EE up to the market potential studies in the base case for the 2014 IRPs, increasing beyond the market potential EE levels would have resulted in a significantly higher-cost resource plan.

The Companies have included in their 2014 IRPs the level of EE they believe is reasonably achievable and economic. In response to a data request seeking the feasibility assumptions of the increased EE levels asserted in their comments, SACE and Sierra Club admitted that they did not conduct a market potential study or make assumptions regarding participation (penetration) rates, or technology to achieve penetration rates, for purposes of preparing their comments, but that their comments were "informed" by their review of market potential studies performed for DEC and other southeastern electric utilities. DEC and DEP asserted that SACE and Sierra Club do not appear to realize that potential does not equal cost-effective or achievable. In their comments criticizing DEC's EE cost assumptions, SACE and Sierra Club again rely upon the LBNL study by Barbose. While this study does make an attempt to adjust cost projections for size of first year impacts, it does not adjust for cumulative market penetration (i.e., the more that has been achieved on a cumulative basis, the higher must be the costs per kWh achieved). Furthermore, the study essentially relies on past spending and impacts to make its projection, which DEC and DEP assert is a very unreliable methodology.

DEC and DEP submitted that, as they did in their 2013 IRP comments, SACE and Sierra Club complain that the EE costs assumed by the Companies in their 2014 IRPs are too high. On pages 8-11 of their comments, SACE and Sierra Club restate four alleged flaws with DEC's EE cost assumptions and methods. As to SACE and Sierra Club's allegation that DEC's long- term EE cost projection included costs incurred by program participants instead of limiting the costs to those paid by DEC. DEC and DEP reply that this allegation is simply false. As to the use of the 60% market saturation, this is based upon the market potential study prepared for DEC and is consistent with reasonable adoption curves for typical measures. As to the criticism that there is no provision for introduction of new EE technology or for reduction in costs of future EE technology, SACE and Sierra Club's comments ignore that generation technology is treated exactly the same way in the IRP (no assumptions are made that generation technology costs will decrease over time). As to their assertion that economies of scale serve to reduce EE program costs as more customers participate, this ignores the reality of EE program implementation: as less expensive EE measures are depleted (the "low hanging fruit"), more expensive measures must be offered.

In addition, DEC and DEP observed that, in part, SACE and the Sierra Club criticize the Companies for not discussing their solar resource capacity value methodology or why the estimates change over time. The Companies have utilized a methodology to determine the peak contribution of solar resources that has been utilized in the current and past IRPs. This methodology simply overlays the solar load profile with the peak hours to determine how much of a solar facility's output can be counted on during the peak hours. The peak hours are those defined in Option B of the avoided cost filing. The load shape in the peak hours determines the amount of capacity that can counted on during each peak hour in both summer and winter periods. These values are summed to determine the overall contribution to peak percentages. A similar methodology is utilized for wind resources. As for these values changing over the years, the Companies continue to review processes and best practices for all methodologies in the IRP. The solar capacity values in the 2014 IRP actually increased as compared to previous years due to the process improvement, thus giving the solar facilities higher value in peak hours.

DEC and DEP also noted that, in their comments, SACE and Sierra Club also allege that DEC and DEP may not have considered current and future environmental regulations, including specifically EPA's Clean Power Plan. Appendix G to both the DEC and DEP 2014 IRPs contain extensive discussion of potential future environmental requirements that will impact the Companies' operations in the coming years, including those related to the Cross-State Air Pollution Rule (CSAPR) and the Clean Air Interstate Rule, the Mercury and Air Toxics Standards (MATS), National Ambient Air Quality Standards, SO_2 Standards, Particulate Matter Standard, Greenhouse Gas Regulation, Cooling Water Intake Structures (Clean Water Act 316(b)), Steam Electric Effluent Guidelines, and Coal Combustion Residuals. The Companies' maintained that their IRP models build in all known capital and O&M costs for environmental compliance.

DEC and DEP further observed that SACE and Sierra Club focus on the impacts of the Clean Power Plan and their own opinion of which coal plants should be considered for accelerated retirement. At the time of the development of the 2014 IRPs, not enough information was available about the Clean Power Plan and the compliance targets for the Companies to include compliance costs in the analysis. As noted previously, the Clean Power Plan Rule has not been finalized, and the rule is likely to undergo significant changes and clarifications considering the extent of comments filed with the EPA regarding the rule. In addition, the plants in question do have planning retirement dates included in the IRP, based reasonably on the current book value of the plants. As the Clean Power Plan, or any other regulation or legislation becomes more certain, the Companies will perform detailed analysis to determine the impacts to the DEC and DEP systems and to each individual generation plant. The Companies evaluate the retirement dates for all generation units based upon changing circumstances, and update retirement dates accordingly.

DEC and DEP stated that, in response to several data requests, SACE and Sierra Club noted that they "do not purport to offer 'proposed resource additions and mix of resources" in their comments. According to DEC and DEP, “if these parties don't have a proposed alternate resource mix and associated costs to analyze and compare, then it belies the validity of the purported cost-effectiveness of their proposals and frustrates any meaningful consideration of their comments. In conclusion, the Companies assert that their IRPs and REPS compliance plans meet all applicable requirements and any SACE and Sierra Club arguments to the contrary should be dismissed."

The Commission finds that DEC and DEP have satisfactorily addressed the issues raised by SACE and the Sierra Club in their initial comments and that no further action is required.

IT IS, THEREFORE, ORDERED, as follows:

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

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

3. That the 2014 REPS compliance plans filed in this proceeding by the IOUs are hereby approved.

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

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

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

7. That the IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.

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

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

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

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

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

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

14. That future IRP filings by DEP and DEC shall continue to provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

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

16. That NC WARN's motion for an evidentiary hearing shall be, and is hereby, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the _26th_ day of June, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-100, SUB 141

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Smart Grid Technology Plans Pursuant to Commission Rule R8-60.1(c)	) ORDER APPROVING SMART GRID) TECHNOLOGY PLANS, DECLINING) TO SCHEDULE A HEARING, AND) REQUESTING COMMENTS ON RULE) REVISIONS

BY THE COMMISSION: On October 1, 2014, in compliance with Commission Rule R8-60.1, Duke Energy Progress, LLC (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (Dominion) filed smart grid technology plans (SGTPs). After several requests for extensions of time for the filing of comments, which the Commission granted, comments were filed on January 9, 2015, by the Public Staff and jointly by the North Carolina Sustainable Energy Association (NCSEA) and the Environmental Defense Fund (EDF). On January 29, 2015, reply comments were filed jointly by DEP and DEC (Duke), by Dominion, and jointly by NCSEA and EDF (NCSEA/EDF).

On October 1, 2015, DEP and DEC filed updates to their SGTPs as required by Commission Rule R8-60.1(b). On the same date, Dominion submitted a letter stating that it had not made any significant revisions to its initial SGTP and that it would continue to implement its initial plan.

Background

By Orders dated April 11, 2012, and May 6, 2013, in Docket No. E-100, Sub 126, the Commission adopted rules requiring electric utilities that file integrated resource plans (IRPs) to include in those IRPs information on how planned “smart grid” deployment would impact the utility’s resource needs. In addition, the Commission established a new requirement, Rule R8-60.1, for these same utilities to file SGTPs every two years with updates in the intervening years. This is the first proceeding before the Commission to consider the utilities’ SGTPs.

Rule R8-60.1(a) states that the SGTPs are intended to be informational. Rule R8-60.1(c) states, “For purposes of this Rule, smart grid technologies are as set forth in Rule R8-60 ....” Rule R8-60(i)(10) states that

> the term “smart” in smart grid shall be understood to mean, but is not limited to, a system having the ability to receive, process, and send information and/or data – essentially establishing a two-way communication protocol. ... [s]mart grid technologies that are implemented in a smart grid deployment plan may include those that: (1) utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility’s distribution or transmission system; (2) optimize grid operations dynamically; (3) improve the operational integration of distributed and/or intermittent generation sources, energy storage,

> demand response, demand-side resources and energy efficiency; (4) provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; and/or (5) provide customers with usage information.

Rule R8-60.1(c) further states that smart grid technologies

> shall also include those that provide real-time, automated, interactive technologies that enable the optimization and/or operation of consumer devices and appliances, including metering of customer usage and provide customers with control options.

Rule R8-60.1(c) lists the information to be included in each utility's SGTP:

> (1) A description of the technology for which installation is scheduled to begin in the next five years, including the goal and objective of that technology, options for ensuring interoperability of the technology with different technologies and the legacy system, and the life of the technology.
> (2) A smart grid maturity model "roadmap," if applicable, or roadmap from a comparable industry accepted resource suitable for the development of smart grid technology.
> (3) Approximate timing and amount of capital expenditures.
> (4) Cost-benefit analyses for installations that are planned to begin within the next five years, including an explanation of the methodology and inputs used to perform the cost-benefit analyses.
> (5) A description of existing equipment, if any, to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.
> (6) Status of pilot projects and projects, including a description of whether and to what extent these projects are or will be funded by government grants.
> (7) A description, if applicable, of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.
> (8) A description, if applicable, of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.
> (9) A description of how the proposed smart grid technology plan will improve reliability and security of the grid.

Summary of SGTPs

DEC's SGTP

Distribution Automation: In its initial submittal, DEC explained that distribution automation (DA) upgrades would be a smart grid priority through 2014. DA involves installation of intelligent line sensors, supervisory control and data acquisition (SCADA) systems, automated re-closers, relay upgrades, and self-healing technologies that improve the reliability of the distribution network and allow power to be restored quickly after outages. DEC described its distribution management system (DMS) as the control system for the distribution grid and the linchpin that enables DA to function. DEC described efforts through 2014 to upgrade its DMS.

Advanced Metering Infrastructure: In its initial filing, DEC stated that in 2013 it began installing advanced metering infrastructure (AMI) that transmits data over radio-frequency waves. DEC stated that AMI would allow the Company to detect and respond to outages more quickly, connect and disconnect service remotely, and provide faster service by eliminating the need for appointments and for personnel to travel. DEC stated that AMI can minimize the need to estimate customer bills and allow customers to manage energy use by providing them with hourly consumption information. DEC stated that at the time of its initial filing there were about 325,000 advanced meters installed in North Carolina, with two-thirds of these deployed to residential customers. DEC stated that the total cost of its advanced meter project was $102 million, with about 25 percent of those costs reimbursed by a grant from the U.S. Department of Energy (DOE).

In its 2015 update, DEC stated that it had begun a limited-scope AMI project to install about 181,300 advanced meters at residences in the Charlotte area, with all but 4,500 being located in North Carolina. As of August 1, 2015, about 19,000 had been installed, with completion planned for the first quarter of 2016.

DEC further stated that it is in the planning phase to exchange about 4,700 large commercial and industrial and special meters with AMI meters. About 3,100 of these would be located in North Carolina, and completion is planned for the second quarter of 2016.

Also in its 2015 update, DEC stated that it is planning AMI deployment for about 20,000 North Carolina meters that were by-passed in the initial phases of its AMI project due to being located in rural areas that were outside the initial communications mesh. A 4G cellular direct connect meter is now available for deploying AMI to these meters, most of which are located at small to mid-sized commercial and industrial customer sites. DEC expects to complete this deployment in the second quarter of 2016.

Additionally, DEC stated that it expects to incur $27.1 million in capital costs for its AMI deployment through the end of 2015 and another $4.8 million in 2016. DEC's 2015 update included confidential cost-benefit information for the three AMI deployments that are underway/planned for 2015-16.

With regard to new technology installations, such as AMI, Rule R8-60.1(c)(5) requires utilities to file "[a] description of existing equipment, if any, to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment." Rather than provide this accounting-oriented information, DEC noted that some meters are being returned to inventory, some are being scrapped, some are being refurbished, and "the remaining are considered to have reached the end of useful life."

In its initial SGTP, DEC discussed the possibility and practicality of a policy that would allow customers to opt-out of having a smart meter installed, as required by the Commission's September 24, 2013 Order Granting General Rate Increase in Docket No. E-7, Sub 1026. DEC stated that it had met with the Public Staff in April of 2014 and that they had agreed that a formal AMI opt-out policy was not warranted at this time due to the limited scope of current AMI projects: "The parties agreed, however, that when larger scale AMI implementation begins, or when AMI meters become the standard metering solution, the topic should be revisited."

In its 2015 update, DEC discussed a new pilot project called Integrated Voltage/Volt-Ampere Reactive Control (IVVC) Pre-Scale Deployment. DEC stated that IVVC is one of the first advanced DMS functionalities that it is installing. IVVC would reduce system demand by optimizing voltage and reactive power across the distribution grid. DEC is demonstrating the technology at seven substations where the project team had completed most its installation work as of August 2015 and was beginning to commission IVVC in DEC's DMS.

<u>DEP's Smart Grid Technology Plan</u>

<u>Distribution Automation:</u> In its initial SGTP, DEP stated that it, too, is deploying DA on its distribution grid. New, intelligent devices like line sensors, SCADA-enabled re-closers and self-healing technology will allow automated or remote operations. When power outages occur, this field equipment will automatically isolate and reenergize sections of the grid. For DEP, the primary component of DA to date is the distribution system demand response (DSDR) project, which included the deployment of a DMS. The DMS is the control system for the distribution grid. DSDR lowers the distribution system's voltage during peak demand conditions, thus deferring the construction of two peaking combustion turbines. DEP completed DSDR in 2014.

<u>Advanced Metering Infrastructure:</u> In its initial SGTP DEP stated that it had replaced about 58,000 older meters in the Carolinas, primarily for commercial and industrial customers, with AMI meters in 2012-13 at a cost of about $45 million. DEP stated that a DOE grant was expected to fully pay for these costs. DEP stated that it has not initiated any further AMI projects.

<u>Feeder Segmentation and Self-Healing Teams:</u> In its initial SGTP, DEP described its feeder segmentation project, an effort involving the replacement of more than 200 aging, unreliable hydraulic re-closers with new three-phase re-closers, and the installation of almost 300 new re-closers in strategic locations. DEP explained that these re-closers are line protection devices that sectionalize the feeder, isolating the section where a fault has occurred, thereby allowing rapid power restoration to customers on unaffected segments by feeding power to them from another direction. This project also involves the deployment of self-healing teams, a technology that uses distribution switches, programmable re-closers, and circuit breakers that are automated and communicate via an intelligent control system. The control system, communications system, and power line devices work as a team to automatically identify and isolate the portion of the system

that is affected by a fault and to minimize the impacts of a power outage by restoring power to as many customers as possible. DEP planned to commission 20 self-healing teams by the end of 2014. Capital costs were estimated at $23.7 million, the majority of which would be reimbursed from a smart grid investment grant.

Phasor Measurement Unit Pilot: Also in its initial SGTP, DEP stated that it is participating in a pilot to evaluate the benefits of phasor measurement units (PMU). A PMU provides real-time voltage and current phase angle measurements that can be used to determine whether the transmission grid is stable.

Condition-Based Monitoring Pilot: DEP's initial SGTP described a pilot to install and evaluate sensors that allow operating transformers to be monitored remotely and continuously for signs of degradation or imminent failure. Sensors will collect and communicate data about gas and moisture in the main transformer tank, gas in the tap-changer compartment of load tap changing transformers, and the condition of bushings.

In its 2015 SGTP update, DEP described four initiatives: 1) self-healing networks, 2) an urban underground automation pilot in Raleigh, 3) an evaluation of moving to a common DMS across the Duke enterprise, and 4) a pilot deployment of "TripSavers II Re-closers."[1] DEP stated that its self-healing networks project is an expansion of the feeder segmentation and self-healing teams project that was described in its 2014 SGTP; as of August 31, 2015, 50 self-healing networks had been deployed across DEP's service territory. DEP stated that it plans to spend $3.6 million in capital through the end of 2015, $2.4 million in 2016, and $3.3 million in 2017 on self-healing networks and that these networks are integrated with DEP's DMS and SCADA systems.

Also in its 2015 update, DEP described an urban underground automation pilot that is underway in Raleigh. This project will loop together equipment that is housed in nine underground vaults in a manner similar to a self-healing network. Technology will sense a loss of power and reroute supplies around the fault, returning power to most customers very quickly. The project will integrate with DEP's SCADA and DMS via a fiber optic communications system. DEP expects capital costs of $3.6 million in 2015 and $1.9 million in 2016 for this project.

In its 2015 update DEP briefly stated that it is evaluating, via a small-scale deployment, the viability of aligning the entire Duke enterprise with a single DMS vendor and platform for operational efficiency and enhanced functionality. As regards the TripSavers ll Re-Closers pilot, DEP stated that in the fall of 2015 about 125 TripSavers would be installed across Duke's jurisdictions, including 62 in North Carolina. DEP will monitor the devices through 2016, and the data will be used to assess the feasibility of a full-scale deployment.

Other Technologies Being Evaluated: In their initial filings, DEC and DEP (jointly, Duke) stated that the Company is monitoring and testing these smart grid technologies: 1) energy storage for a variety of applications; 2) the "internet of things" and connected end-use devices such as

[1] According to S&C Electric Company's website, TripSaver® II Cutout-Mounted Re-Closer is a self-powered, electronically controlled single-phase re-closer using vacuum fault interrupter technology, and is offered in voltage ratings of 15-kV and 25-kV. That website further stated that "this Smart Grid solution" can eliminate some permanent and momentary outages.

appliances; 3) charging technologies for plug-in electric vehicles; 4) micro-grids, specifically the McAlpine pilot in South Charlotte; 5) distributed intelligence, which could alleviate problems caused by the intermittency of photovoltaic solar generators; 6) low-voltage power electronics, which offers numerous improvements to distribution grid design and operations; and 7) the interoperability of grid field devices through its ‘coalition of the willing’ effort with device vendors.

In terms of micro-grids, Duke’s 2015 updates discussed two pilots. The McAlpine micro-grid allows Charlotte fire stations to remain fully operational during prolonged grid outages. This micro-grid includes islanding switches, solar arrays, and batteries. A second micro-grid pilot at DEC’s Mount Holly facility also uses solar generation and battery energy storage, but adds an “open field message bus distributed intelligence platform” with wireless communications to devices. This pilot will provide an islandable operational micro-grid to test interoperability across devices and applications.

Duke’s 2015 updates described three energy storage projects that are in the planning and development stages and for which field installations are expected by the end of 2016: 1) the Rankin battery storage project pairs a 300-kW high-energy battery and a high-power capacitor with a 402-kW commercial solar installation located three miles away; 2) Duke is partnering with UNCC’s EPIC Center[1] on the Marshall energy storage project. This effort involves a 1.2-MW solar facility and a 250-kW storage system. This project is testing efforts to incorporate weather, circuit and use data to optimize the solar facility’s operations throughout the day and year to reduce voltage regulator operations that result from solar intermittency; and 3) testing of multiple home battery units.

Duke’s 2015 updates also discussed a recently concluded field testing of a low-voltage power electronic system. Duke stated that it had field tested using this system to manage power flow and peak demand, provide volt-VAR[2] optimization, enhance power quality, provide outage and fault detection and smooth solar generation’s intermittency. Duke is evaluating the need for a larger pre-scaled field test prior to committing to deployment.

<u>Dominion’s SGTP</u>

<u>Advanced Metering Infrastructure:</u> The Company installed more than 260,000 smart meters in Virginia starting in 2009. Dominion stated that it has not made a definitive business decision to deploy AMI across its entire service territory, but its preliminary plan is to have about 2 percent of its North Carolina meters converted to smart meters in 2019. Dominion is focusing on AMI’s ability to provide remote meter reading, remote connection and disconnection of service, outage and restoration messaging, dynamic pricing, and voltage conservation.

<u>Synchro-phasor Measurement System:</u> Dominion stated that it is incorporating synchro-phasors into its substations and expects to spend $1 million annually across its system deploying this technology. Dominion stated that synchro-phasors provide precise, high resolution measurements of grid voltage and current, taken at locations over the entire transmission grid.

[1] University of North Carolina Charlotte Energy Production and Infrastructure Center.

[2] VAR or “volt-ampere reactive” is a unit for measuring reactive power.

Measurements are taken at very high speeds such as 30 times a second, which is 100 times faster than the conventional method of monitoring the transmission grid.

Kitty Hawk Micro-Grid Demonstration Project: Dominion is studying the interoperability of distributed generation technologies at its Kitty Hawk service center. The micro-grid demonstration includes a behind-the-meter diesel generator, a utility feed, a five-kW horizontal-axis and three vertical-axis wind turbines (3-, 4- and 5-kW), a lithium ion battery with a 75-kW storage capacity and a 25-kW discharge rate, a 6-kW solar array, protective relays, inverters, control software, metering, circuit breakers, a residential-size fuel cell, and round-the-clock monitoring.

Comments and Reply Comments

Comments of the Public Staff

The Public Staff summarized the initial SGTPs that DEC, DEP, and Dominion had submitted, stating that it had done a general review rather than focusing on strict adherence to the nine requirements of Rule R8-60.1(c), "with the intent of developing recommendations for improvements to future Smart Grid Plans." Those recommendations are as follows.

Smart grid accomplishments and expenditures incurred to date. The Public Staff stated that it would like to see more information about how the installed technologies and the information they provide will "be used in future grid operations or serve as the foundation of future grid improvements or utility services." The Public Staff noted that all three utilities listed AMI as a smart grid project and noted the possible benefits of AMI, but that "little information about how these benefits would be implemented as new customer services or improvements in service quality" was provided. The Public Staff noted that all three utilities had installed AMI meters that contained communication functionality, but that "none of the utilities is using or plans to use this functionality." The Public Staff stated that utilities should continue to seek cost-effective ways to provide customers with more detailed usage data and enhance customers' ability to use this information to manage and control their energy consumption.

Projects and expenditures expected in the next five years. The Public Staff believes future smart grid technology plans should include a more detailed roadmap

> that explains the smart grid projects and pilots underway, how those projects and pilots will inform the IOU's decision-making process regarding future investments in smart grid technologies, a projection of investments under consideration, including any financial impacts related to existing assets, and significant mileposts associated with the project and a schedule of activities.

Cost-benefit analyses. The Public Staff noted that the three utilities did not provide any cost-benefit analyses. The Public Staff stated that

> while the utilities technically complied with the requirements of R8-60.1(c)(4), which requires cost-benefit analyses for projects 'that are planned to begin within the next five years,' the Public Staff believes that future Smart Grid Plans should

> include a discussion of any estimated cost-benefit analyses done to justify the initial investment of funding for research and pilot projects. This would allow the Commission to review the progress of the projects and their intended benefits.

A forecast of impacts to customers, rates, and cost of utility service resulting from smart grid investments. The Public Staff stated that it would be beneficial if future plans include a forecast of how projects would impact customer services, rates, and/or the utility's cost of service. "While each IOU [investor-owned utility] provided an explanation of its smart grid investments ..., the discussion of the benefits and impacts of AMI-related projects could have been more detailed." The Public Staff noted specifically that AMI has the potential of new services in areas such as billing, usage data, energy management, and communications between the utility and customers.

Reliability and grid security. The Public Staff stated that future smart grid plans should identify specific ways the proposed technology would improve grid reliability and security.

State-specific and system-wide programs and impacts. The Public Staff stated that future SGTPs should provide information on implementation, rates, expenditures, and cost-benefit analyses on a State-specific basis.

Other issues. The Public Staff identified other issues that it believes "are a fundamental part of the debate and dialogue associated with the smart grid." In terms of AMI, the Public Staff stated that some customers are concerned about exposure to radio frequencies and privacy. As smart meters are deployed more widely, utilities will need more formal AMI meter opt-out policies that appropriately balance customer desires with AMI benefits. The Public Staff noted that the utilities have significant book value in advanced meter reading (AMR) meters that were installed in the early 2000s. Replacing these AMR meters with AMI meters should be based on robust analyses of the benefits and the rate impacts related to this potentially stranded investment. The Public Staff noted that smart grid technologies can allow customers to reduce their energy bills and that the utilities should continue to investigate cost-effective opportunities for customers to manage their consumption with time-based rates that respond to the hourly cost of energy. The Public Staff stated that smart grid technologies have the potential to "disrupt the current power generation and delivery business model," and these technologies will "likely require examination of the issues of cost-causation and cost allocation." Lastly, the Public Staff said that the Commission might want to require the utilities to

> submit a schedule for smart grid technology development and implementation, including a tentative schedule of critical decisions to be made. ... Particularly in regard to the AMI-related projects, the Smart Grid Plans did not indicate by what date the IOU would finalize any decision to adopt or reject implementation .... While the initial Smart Grid Plans filed by DEC, DEP and DNCP [Dominion] comply with Rule R8-60.1, inclusion in future Smart Grid Plans of the additional information and discussion described in these comments would be beneficial to the Commission and parties.

Comments of NCSEA/EDF

In both their initial and their reply comments, NCSEA/EDF asserted that the SGTPs filed by DEP, DEC, and Dominion are deficient because they failed to provide adequate information on customer and third-party access to energy consumption data, because they failed to provide cost-benefit analyses, and because they failed to provide adequate technology descriptions. NCSEA/EDF stated that the utilities did not comply with the following provisions in Rule R8-60.1:

> (c) ... The plan shall include:
>
> (1) A description of the technology for which installation is scheduled to begin in the next five years, including the goal and objective of that technology, options for ensuring interoperability of the technology with different technologies and the legacy system, and the life of the technology. ...
>
> (4) Cost-benefit analyses for installations that are planned to begin within the next five years, including an explanation of the methodology and inputs used to perform the cost-benefit analyses. ...
>
> (7) A description, if applicable, of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.
>
> (8) A description, if applicable of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties. ...

NCSEA/EDF stated that

> [T]he utilities provided no cost-benefit analyses whatsoever .... Costs were discussed at various points and benefits were discussed at differing points, but nowhere do the filed SGT plans contain cost-benefit analyses. Accordingly, the SGT plans filed by the utilities are necessarily deficient in this regard.

NCSEA/EDF cited an Indiana case in which Duke Energy Indiana had filed much greater detail about its plans to deploy smart grid technologies than DEC and DEP had provided in this proceeding.

NCSEA/EDF requested that the Commission require the utilities to file supplemental information to fully comply with Rule R8-60.1 or hold a hearing on the adequacy of the plans. According to NCSEA/EDF, the Commission should decline to issue an order accepting the plans until the utilities have addressed their deficiencies. NCSEA/EDF said the Commission should require each utility to provide a cost-benefit analysis for full smart grid deployment throughout its territory. NCSEA/EDF also requested that the Commission initiate a rulemaking to adopt clear data access policies for customers. NCSEA/EDF stated that they

> recognize that the Commission will have to confront and resolve the need to facilitate access to energy usage data while safeguarding customer privacy. ... [The Commission should] address whether it is appropriate for the utilities to charge a fee for access to information that belongs to a customer.

NCSEA/EDF noted that in its August 23, 2013 Order Requesting Additional Information and Declining to Initiate Rulemaking,[1] "the Commission indicated that it expects the utilities to include information [in their 2014 SGTPs] about what customer usage data is being collected and how it will be accessed by customers and third parties .... NCSEA and EDF urge the Commission to view this as an appropriate time to open a rulemaking docket to adopt clear data access policies for the State."

<u>Reply Comments of Duke</u>

In its reply comments, Duke addressed NCSEA/EDF's concerns. Duke stated that most of the projects described in the initial plans were initiated prior to the Rule's adoption and that the deployments described in the plans were implemented with "significant U.S. Department of Energy grant funding, and therefore did not undergo a 'cost-benefit analysis'...." Similarly, Duke stated

> As of the time of the filing of the 2014 SGTPs, the Companies did not have any technologies which were scheduled for implementation in the next five years, thereby rendering many of the requirements of Rule R8-60.1 inapplicable .... The Companies respectfully submit that their 2014 SGTPs meet all applicable statutory and Commission requirements and should be approved.

As to NCSEA/EDF's proposal that the utilities be required to analyze a full smart grid deployment, Duke stated that it is not aware of any standard set of equipment or technologies that define a "smart grid," but understands that technologies are ever evolving.

In response to NCSEA/EDF's assertions that the Commission's Order in E-100, Sub 137 required the utilities to file additional information about customer access to usage data in the 2014 SGTPs, Duke said

> the Companies note that existing processes and mechanisms to provide customers' usage data have not changed based on any smart grid technology deployment at this time; therefore, [they] did not believe it was necessary to recount in the 2014 SGTPs the Companies' existing processes as described in their filings in Docket No. E-100, Sub 137, as NCSEA and EDF apparently believe the Companies should have.

Duke's reply comments also addressed the Public Staff's concerns. The Companies agreed to provide information in future plans on new customer services they intend to implement using smart grid technologies once those services are planned and scheduled. While the Public Staff requested a more detailed smart grid roadmap with a schedule of planned deployments, Duke

[1] Docket No. E-100, Sub 137.

stated that a more detailed roadmap with vague assumptions and timelines that would undoubtedly change would "cause confusion for stakeholders:"

> The Companies question the purpose and effectiveness of providing arbitrary dates for decisions to be made, or technologies to be implemented in future SGTPs. The Companies attempted to provide a high level of transparency into the 'Technology Exploration' or research and development area .... Any attempt by the Companies to try and provide a timeline of when those technologies would be feasible for mass deployment would be a guess at best ....

Duke provided a summary of its smart grid investments to date. It stated that DEP invested about $294 million in capital on digital grid technologies since 2007 and received about $68 million in DOE grant funding in partial reimbursement. DEP received another $27 million in DOE grant funding toward operating and maintenance (O&M) costs. Duke stated that DEC invested about $204 million in capital on digital grid technologies since 2007 and received about $51 million in DOE grant funding as partial reimbursement. DEC received another $1-million DOE grant for O&M costs.

Duke said it would be burdensome to provide detailed reporting on smart grid ideas that are determined not to be viable. Duke did agree to include in future plans the cost-benefit analyses for projects that are approved and scheduled for installation:

> However, the Companies believe that research and pilot projects are undertaken for the primary purpose of determining and validating the costs and benefits of a technology to more accurately perform a cost-benefit analysis of a full or larger scale deployment. Therefore, the Companies do not believe it is appropriate to include cost-benefit analyses for research and pilot projects.
>
> ...
>
> The Companies assert that the SGTP, like the IRP, is not designed to be an application for approval of a specific project, nor is it filed as part of a cost recovery proceeding, and therefore would oppose inclusion of rates impact and cost of utility service from smart grid investments in future SGTPs.

While the Public Staff stated that the plans should have included more information about how grid investments would improve reliability and security, Duke stated that they believed they had provided this information in their 2014 SGTPs, but agreed to try to provide more such explanations in future plans. In response to the Public Staff's recommendation that future SGTPs include deployment details on a State-specific (rather than system-wide) basis, Duke stated that this would be burdensome to provide:

> The Companies did, and propose to continue to, provide project expenditure information on an Operating Company basis within their SGTPs, which in some cases also fully captures the scope of the project.

Duke agreed with the Public Staff that additional discussion of AMI meter opt-out policies should be addressed when AMI meters are more widely deployed. They stated that any customer opting-out of an AMI meter installation should be responsible for the reasonable incremental costs incurred by the utility as a result. Duke agreed with the Public Staff that future AMI deployments should consider both the benefits of conversion to AMI technology and the costs, including stranded investments.

Duke stated that both its AMR and AMI meters have two-way communications. Both kinds of meters communicate by sending usage data and other information to the utility, and the utility communicates by sending control signals back to the meter. Duke clarified by stating that

> the advanced meters installed by the Companies also contain an internal radio, which can enable communication between the meter and consumer devices. This is the portion of the [AMI] technology functionality for which the Companies currently have no plans to enable.
>
> The Companies agree that the expansion of AMI meter deployments could enable more products and services to allow customers to manage their energy usage. At such time when those types of investments are planned and scheduled by the Company, and provided to the majority of customers, that information will be appropriately included within the SGTPs.

Duke disagreed with NCSEA/EDF's assertions that the DEC and DEP plans were deficient, stating that NCSEA/EDF's requests for supplemental filings and an evidentiary hearing to provide more information should be denied. As to the provision of customer usage information, Duke stated that on September 23, 2013, DEC and DEP filed a joint verified response to the Commission's August 23, 2013 Order Requesting Additional Information and Declining to Initiate Rulemaking in Docket No. E-100, Sub 137. The response set forth the customer usage information that is available to DEC and DEP's customers as well as the process by which customers can authorize release of that information to third parties. As to the smart grid filings that Duke has made in Indiana and Ohio, they

> were made to the appropriate state commission in cost recovery proceedings, initiated by legislation, for the purpose of obtaining those commissions' approval of cost recovery to implement large smart grid programs. ... The North Carolina 2014 SGTPs filed by DEC and DEP reflect the most complete and accurate information currently available and as required by this Commission's rules, not what is required by the Ohio or Indiana commissions.

As to NCSEA/EDF's request that the Commission initiate a rulemaking to adopt data access policies, Duke explained that this might be premature and that the Commission may instead "want to wait until such time as the Companies have additional details to provide on new types of data collected or used by smart grid technologies in the future."

Reply Comments of Dominion

Dominion also opposed NCSEA/EDF's request for an evidentiary hearing and their proposal that the utilities be required to supplement their filings:

> ...[T]he Company purposefully and methodically addressed each Rule R8-60.1(c) reporting guideline .... As all SGT reporting guidelines were adhered to ..., the Company strongly disagrees with NCSEA/EDF's unsubstantiated request for an evidentiary hearing or additional proceedings ....

Regarding NCSEA/EDF's desire to have more information about customer access to usage data filed with the SGTPs, Dominion referenced Docket No. E-100, Sub 137, as Duke had. As for cost-benefit analyses for smart grid deployment, Dominion stated that it had provided such information "where it currently exists" and also explained that "the Company is still internally evaluating its options regarding timing for deploying certain smart grid projects, such as AMI."

Dominion noted that this is the Commission's first smart grid plan proceeding and stated that as "it is likely that NCSEA/EDF will request evidentiary hearings or supplemental re-writes" of the utilities' plans in the future, "some general guidance in this area may prove valuable to all parties." Dominion went on to state:

> The Company did not interpret the Commission's intent in approving Rule R8-60.1 to create a separate and distinct smart grid resource planning process that places procedural and substantive requirements on the utilities equal to or greater than the full IRP process. DNCP submits that the purpose of the rule is limited to providing more focused "reporting" on the utility's current smart grid plans to support the full Integrated Resource Plan and not to regulate the utilities' smart grid deployment similar to a full IRP process. ... The Commission should make clear that this smart grid resource planning process is not intended to usurp utility management's role in making prudent, least cost business decisions regarding when and how to proceed with smart grid deployment for the benefit of the Company's customers and is not a substitute for rate recovery and/or regulatory approval proceedings.

Dominion also responded to the Public Staff's comments, stating that it agrees

> with the Public Staff that it is reasonable to more broadly track and include sub-projects within future SGT Plans and to report on whether such sub-projects are fully deployed or the Company has pivoted in another direction away from an ongoing smart grid strategy.

In terms of the Public Staff's request that utilities provide a "roadmap" that addresses smart grid projects and pilots and how they will inform future investment decisions, Dominion stated that it can develop a more "high level summary in support of its next SGT Plan and address the more detailed recommendations within the broader SGT Plan itself." As to the Public Staff's desire for more information about smart grid impacts on grid reliability and security, Dominion stated that it will continue to clearly identify ways smart grid technology can improve both in future plans.

Dominion stated that it has concerns with the granularity of the Public Staff's request for the "rates, expenditures, and cost-benefit analyses" of all smart grid efforts to be analyzed on a State-jurisdictional basis, and it requested that the Commission not impose any express requirements in this regard. Especially in the area of AMI, Dominion "requests that the

Commission not impose detailed rate impact reporting requirements" in future smart grid plans, "as the Company continues to study the potential for full AMI deployment for our customers."

Dominion stated that its current smart meter policy provides a clear process for customers to opt-out of an AMI meter. "As AMI is more widely deployed, the Company will continue to evaluate its opt-out policy to ensure it continues to fairly and appropriately serve customer's [sic] interests."

Like Duke, Dominion expressed reservations about the Public Staff's proposal for utilities to file cost-benefit information for pilot projects as such requirements could affect the Company's efforts to innovate on a small scale with new smart grid technologies before moving toward full deployment:

> [R]eporting on the costs and benefits of future pilots should be more qualitative in nature, showing the potential reliability, operational, and/or customer benefits the pilot is designed to achieve. More refined analyses of costs and benefits would then be justified upon full scale deployment of a given smart grid initiative.

Dominion also stated that it "supports certain of the refinements recommended by the Public Staff and will endeavor to incorporate them" in future SGTPs.

Discussion, Findings and Conclusions

NCSEA/EDF were critical of the utilities' smart grid plans, asserting that they did not comply with the Commission's Rules. The Public Staff found that the SGTPs "generally" complied. The utilities argued strongly that they fully complied. Upon review of the plans, as well as the DEC and DEP 2015 updates, the Commission finds that the DEC and DEP plans did not always follow the ordering in the Rule, which made compliance a little difficult to audit. However, the utilities are correct in that some Rule provisions are irrelevant unless the utility has made the decision to deploy a specific smart grid technology in the next five years. Thus, despite NCSEA/EDF's criticisms, the Commission finds that the plans comply with the Rule, and the Commission will approve them, noting the utilities' willingness to provide additional information in future plans.

Notwithstanding the requests for more information, the Commission finds that the SGTPs on the whole were instructive and helpful. It appears that both Duke and Dominion are playing leadership roles in the smart grid arena, gaining expertise and encouraging vendors to develop applications that could someday be cost-effective and beneficial for customers. As discussed later in this Order, the Commission will seek comments on whether and how to amend its smart grid rules to better leverage the information in the SGTPs to the benefit of the Commission and parties. First, however, the Commission will address several specific concerns raised by the SGTPs.

Metering

While the utilities all discussed their AMI deployments and pilots, the Commission finds that it would be helpful to have a "big picture" summary of the status of metering technologies in the State. Therefore, the Commission will require the utilities in their 2016 SGTPs to submit a clear accounting of the extent to which AMI meters have been installed in North Carolina and the classes and/or tariffs of customers that now have AMI. In addition, the Commission will require the utilities to provide in their 2016 SGTPs a recap of how many meters in North Carolina use traditional metering technology and/or AMR technology. As appropriate, all three utilities should provide information on any adjustments they have made to their capital accounting due to AMI, including the dollar amount of write-downs of their meter inventories. They should also provide a discussion of what services or functions the AMI meters facilitate, which of these services or functions have been activated, and whether there are any plans for pursuing others. Finally, the utilities should provide the predicted life-spans of the AMI installations that have been made.

Customer Opt-Out of AMI

In its 2014 SGTP, DEC stated that it began deploying advanced meters in 2013 and that at the time of that filing the Company planned to install about 382,000 advanced meters in its North and South Carolina territories. In its 2015 update, DEC stated that it plans to install almost 200,000 AMI meters in North Carolina via a deployment that is underway now and that is slated to be complete by the middle of 2016. While Duke and the Public Staff have in the past agreed that there was no need to address smart meter opt-outs until there is a large deployment in the State, the Commission finds that DEC's AMI installations are significant enough to warrant further discussion of this issue now. Therefore, the Commission will require DEC to submit information explaining how it is handling or proposes to handle AMI opt-out requests during the deployments described in its 2015 SGTP update. The Commission is especially interested to know whether the Company is allowing or proposes to allow opt-outs, its rationale for the approach chosen, and whether it would commit to honor those opt-outs indefinitely.

Distribution Voltage Control

DEC and DEP are considering at least two approaches to managing voltage on the distribution grid: low-voltage power electronics and IVVC. In addition, DEP has already installed DSDR, and Dominion is evaluating smart meters as a means of controlling distribution system voltage. In their 2016 smart grid plans, DEC, DEP, and Dominion should compare these approaches (and others as appropriate) in terms of costs and benefits, both of which may be expressed, if necessary, in very broad and qualitative terms.

Common DMS

In its 2015 update, DEP stated that it is evaluating the viability of aligning the entire Duke enterprise with a single DMS vendor and platform. In their 2016 SGTPs, DEC and DEP should discuss whether the Companies intend to pursue moving the DEC and DEP distribution grids toward a common operating platform and, if so, over what time horizon. To the extent that no decision has been made on this question when the SGTPs are filed, they should nonetheless provide the Commission with a discussion of the issues involved, including a high-level, indicative range of the possible costs, the benefits and possible disadvantages of a common platform, and approximately how long it would take to accomplish if the utilities were to pursue it.

DEC's Residential Energy Research Pilot Project

On October 22, 2013, DEC notified the Commission of its intent to begin a pilot involving up to 60 residential customers served by the McAlpine substation in Charlotte to research new grid optimization tools that could lead to lower costs and higher reliability. DEC stated that it would use "data loggers" to understand which appliances drive energy use and demand and to document how weather or grid conditions impact customer usage. DEC's notification stated that the Company would collect data for two years, ending in December of 2015. DEC should provide summary results of this pilot in its 2016 SGTP if it has not otherwise provided them to the Commission by that time.

<u>NCSEA/EDF's Concerns</u>

NCSEA/EDF asserted that the utilities' SGTPs should have included more information about plans for providing customers with additional information about their electricity use. NCSEA/EDF stated that the plans should have included more information about how usage information can be transferred to third parties. In addition, NCSEA/EDF complained that the utilities neglected to file cost/benefit analyses for smart grid technologies. NCSEA/EDF requested that the Commission require the utilities to file supplemental information or hold an evidentiary hearing. They also requested that the Commission initiate a rulemaking to establish clear data access policies. The utilities argued that they had filed all of the required information and, to the extent that they did not, it was because they did not have smart grid installations scheduled to begin "in the next five years" at the time they filed their first smart grid plans in 2014.

Rule R8-60.1(c) lists the information to be included in each utility's SGTP:

> (1) A description of the technology for which installation is scheduled to begin in the next five years, including the goal and objective of that technology, options for ensuring interoperability of the technology with different technologies and the legacy system, and the life of the technology.
> (2) A smart grid maturity model "roadmap," if applicable, or roadmap from a comparable industry accepted resource suitable for the development of smart grid technology.
> (3) Approximate timing and amount of capital expenditures.
> (4) <u>Cost-benefit analyses for installations that are planned to begin within the next five years</u>, including an explanation of the methodology and inputs used to perform the cost-benefit analyses.
> (5) A description of existing equipment, if any, to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.
> (6) Status of pilot projects and projects, including a description of whether and to what extent these projects are or will be funded by government grants.
> (7) A description, <u>if applicable, of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.</u>
> (8) A description, <u>if applicable, of how third parties will implement or utilize any portion of the technology</u>, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.
> [Emphasis added.]

The Commission agrees with the utilities; a strict reading of the Rule indicates that the additional information that NCSEA/EDF wanted pursuant to the Rule is not required. However, NCSEA/EDF correctly pointed out that the utilities failed to file the information required by the Commission's August 23, 2013 Order in Docket No. E-100, Sub 137. In that proceeding, NCSEA requested that the Commission initiate a rulemaking to address the accessibility of customer data. The August 23, 2013 Order states

> The Commission is persuaded that there may be a need for clarification of the manner in which Rule R8-51 and the IOUs' codes of conduct are applied in granting access to customer information. Therefore, the Commission requests that the IOUs provide detailed verified responses to the questions included in Appendix A attached to this Order. However, the Commission is not persuaded that it is appropriate at this time to initiate a rulemaking to address the accessibility of customer usage data .... Instead, it will be a more efficient use of time and resources to utilize the information provided in the IOUs' SGT plans to assist in determining whether a rulemaking is needed and, if so, the parameters of any proposed new rules. Thus, the Commission is inclined to allow the IOUs to address these issues in their SGT reports to be filed on October 1, 2014. Those reports should provide information about the customer usage data currently being collected and contemplated to be collected. Given that information, the Commission and parties will be better equipped to address the need for new guidelines for access by customers and third parties to this information.

Subsequently, DEC, DEP and Dominion filed the answers to the questions as required by the Order. However, DEC and DEP did not specifically "address these issues in the SGT reports," because their "processes and mechanisms to provide customers' usage data have not changed." Duke stated in its reply comments that the Commission might want to delay such a rule proceeding until the Companies can provide more information on the kinds of data collected or used by smart grid technologies. Similarly, Dominion did not address the need for rulemaking, and instead asserted that its "SGT Plan generally addresses how both customers and third parties may access customer data."

Therefore, while the Commission will not require the utilities to supplement their 2014 filings as NCSEA/EDF proposed, the Commission will nonetheless require them to update their responses to the questions posed in the Commission's August 23, 2013 Order and include those responses in their 2016 SGTPs. In addition, they are to address in their 2016 SGTPs whether the Commission's rules should be updated at that time in order to address customer and third party access to usage data. Finally, if any party believes that rule changes are needed, they should file their proposed rule changes in the 2016 SGTP docket.

NCSEA/EDF also requested that a hearing be scheduled to address the adequacy of the 2014 SGTPs. Rule R8-60.1(d) states that a hearing "may be scheduled at the discretion of the Commission." Since the Commission has concluded that the smart grid plans filed by the utilities comply with the Rules and that the issue of amending the Commission's Rules relative to customer and third party access to usage data will be addressed in the 2016 SGTPs, there is no need for a hearing at this time.

The Public Staff and NCSEA/EDF had several requests for additional information to be filed in the SGTPs. The utilities shall address these requests for additional information in future plans if they are able to do so.

Future Smart Grid Proceedings

Several parties noted that this is the first round of SGTPs, and all anticipated that future plans would be refined to better address the Rule's requirements and the interests of the parties and the Commission. As noted earlier, Dominion requested guidance as to the scope and intent of future smart grid proceedings. Dominion stated that the purpose of the smart grid rules "is limited to providing more focused 'reporting' on the utility's current smart grid plans ... not to regulate the utilities' smart grid deployment similar to a full IRP process." Duke asserted that "the SGTP, like the IRP, is not designed to be an application for approval of a specific project, nor is it filed as part of a cost recovery proceeding ...." The Commission agrees that these proceedings are intended to be informative, and the Commission does not anticipate using them to order utilities to make specific smart grid investments[1] nor are they a means by which utilities should seek to secure advance prudency reviews of smart grid investments.

The Commission has found the SGTPs filed by DEC, DEP, and Dominion to be informative. The utilities are expending considerable resources to understand, demonstrate, and deploy new technology to better serve their customers, to more effectively manage the grid, and to better manage intermittent generation. The Commission has a need to understand new technology and its economic and policy implications. As a means of expanding the Commission's understanding of new grid technologies, this first smart grid proceeding has had some limitations. Short of presiding over an evidentiary hearing, there is no mechanism in the current rules for the Commission to pose questions or dialogue with the utilities and parties about the issues posed by technology choices. The Public Staff's numerous recommendations that future SGTPs contain additional information inform the Commission's finding that the current rules are deficient. While the Commission could increase the SGTP filing requirements, this approach could become burdensome for the utilities because of the wide range of questions that the Commission and parties might want addressed. In addition, while evidentiary hearings can be valuable, that aspect of the current rule appears to invite litigation, which in this sphere the Commission believes is unproductive. Therefore, the Commission requests that parties file comments suggesting ways the smart grid rules could be amended to enhance the informative aspects of future smart grid proceedings while reducing the litigious aspects of the current rules.

IT IS, THEREFORE, ORDERED as follows:

1. That NCSEA/EDF's requests that DEC, DEP, and Dominion be required to supplement their 2014 SGTPs and that an evidentiary hearing be scheduled regarding the adequacy of those plans are hereby denied;

[1] It should be noted however that General Statute 62-42 grants the Commission authority to order an investor-owned utility to make equipment improvements if necessary to assure that customers receive adequate and sufficient electric service.

2. That DEC, and DEP and Dominion as appropriate due to their limited AMI deployments in North Carolina, shall include in their 2016 SGTPs summaries of their metering technologies and plans, including the accounting implications of any stranded costs, as discussed in this Order;

3. That DEC shall address the issue of AMI opt-outs relative to its current and planned AMI deployments by December 1, 2015, and parties may file reply comments by January 22, 2016;

4. That DEC, DEP, and Dominion shall include in their 2016 SGTPs a discussion of the variety of technologies for controlling voltage on the distribution grid as discussed in this Order;

5. That DEC and DEP shall include in their 2016 SGTPs a discussion of moving to a common distribution grid operating platform, as discussed in this Order;

6. That DEC, DEP, and Dominion shall update their responses to the questions posed in the Commission's August 23, 2013 Order and include those responses in their 2016 SGTPs;

7. That DEC, DEP, and Dominion shall address in their 2016 SGTPs whether the Commission's Rules require updating in order to address customer and third party access to usage data; and

8. That parties are requested to file comments proposing amendments to Commission Rule R8-60.1 so that future smart grid proceedings are more informative, as discussed in this Order. Comments shall be filed by December 1, 2015, and reply comments shall be filed by January 8, 2016. Comments should be filed in Docket No. E-100, Sub 126.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of November, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

Commissioner Susan Warren Rabon did not participate in this decision.

DOCKET NO. E-100, SUB 144

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Consider	)	ORDER ADOPTING
the Adoption of Proposed Commission	)	COMMISSION RULE R8-70
Rule R8-70	)	

BY THE COMMISSION: On April 1, 2015, the North Carolina General Assembly ratified Senate Bill 305, and the Governor signed it into law the following day. See N.C. Session Law 2015-3. Among other things, Senate Bill 305 enacted G.S. 62-133.14, a new section of Chapter 62, the Public Utilities Act. In summary, G.S. 62-133.14 provides for the cost recovery of costs incurred by an electric utility to acquire, operate and maintain interests in electric generating facilities purchased from a joint municipal agency. Pursuant to G.S. 62-133.14(a), the Commission is required to adopt rules to implement the provisions of the new statute.

On June 12, 2015, Duke Energy Progress, Inc. (DEP) and the Public Staff (collectively, Movants) jointly filed an application for adoption of proposed Commission Rule R8-70 in the above-captioned docket. In summary, Movants stated that the proposed rule would implement the cost recovery provisions of G.S. 62-133.14. Further, Movants stated that proposed Rule R8-70 was developed through a deliberate and lengthy process by DEP and the Public Staff, and reflects input from the Carolina Industrial Group for Fair Utility Rates II (CIGFUR) and the Carolina Utility Customers Association, Inc. (CUCA). In addition, Movants noted that on May 12, 2015, the Commission issued its related Order Approving Transfer of Certificate and Ownership Interests in Generating Facilities in Docket Nos. E-2, Sub 1067 and E-48, Sub 8, in connection with the transaction contemplated by G.S. 62-133.14. Finally, DEP requested expedited approval of the proposed rule on or before June 24, 2015, in order to facilitate the closing of the transaction between DEP and the North Carolina Eastern Municipal Power Agency on July 1, 2015.

On June 16, 2015, the Commission issued an Order Requesting Comments Regarding Proposed Rule R8-70. The Order allowed petitions to intervene and initial comments to be filed by June 30, 2015, and reply comments to be filed by July 7, 2015.

On June 17, 2015, CIGFUR filed a petition to intervene. On June 23, 2015, the Commission issued an Order granting CIGFUR's petition.

No other persons intervened in the docket and no comments or reply comments were filed.

Based on the foregoing and the record, the Commission is of the opinion that Rule R8-70 as proposed by DEP and the Public Staff is consistent with the provisions of G.S. 62-133.14, will assist the Commission to properly implement the statute, and will serve the public interest. In addition, the Commission concludes that there is good cause to adopt proposed Rule R8-70. Therefore, Commission Rule R8-70, attached hereto as Attachment A, shall be, and is hereby, adopted effective the date of this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of July, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

ATTACHMENT A

RULE R8-70

Rule R8-70 COST RECOVERY FOR COSTS INCURRED BY AN ELECTRIC PUBLIC UTILITY TO ACQUIRE, OPERATE AND MAINTAIN INTEREST IN ELECTRIC GENERATING FACILITIES PURCHASED FROM A JOINT MUNICIPAL POWER AGENCY

(a) Definitions.

(1) Unless listed below, the definitions of all terms used in this rule shall be as set forth in G.S. 62-133.14.

(2) "Acquired plant" means a joint agency's proportional ownership interest in electric generating facilities purchased by an electric public utility prior to December 31, 2016.

(3) "Acquisition costs" means the amount paid by an electric public utility on or before December 31, 2016, to acquire the proportional ownership interest in electric generating facilities from a joint agency, including the amount paid above the net book value of the generating facilities. Acquisition costs include the amounts recorded by the joint agency in its accounting records for plant, accumulated depreciation, net nuclear fuel, spare parts, fuel and materials and supplies inventories, construction work in progress, and any other items related to the acquired plant, plus the amount paid by an electric public utility above the net book value of the generating facilities.

(4) "Financing costs" means the debt and equity return on the electric public utility's average rate base investment determined using the weighted average net of tax cost of capital as authorized by the Commission in the electric public utility's most recent general rate case, including gross-up for income taxes.

(5) "Joint agency" means a joint agency established under Chapter 159B of the General Statutes.

(6) "Levelized" means an even amount of revenue requirement over a period of time that is equivalent to the present value of the stream of revenue requirements that would be determined for the same period of time based upon the declining book value of the items subject to the levelization. The return to be used in the present value calculations is based on the net of tax rate of return authorized by the Commission in the utility's last general rate case.

(7) "Non-fuel operating costs" means the reasonable and prudent costs incurred to operate and maintain electric plant in service and the related depreciation and amortization expense, nuclear decommissioning expense, Commission regulatory fee, income taxes and property taxes, but excluding costs recoverable under G.S. 62-133.2.

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(8) "Joint Agency Asset rider" means a charge or rate established by the Commission annually pursuant to G.S. 62-133.14 to allow an electric public utility to recover the North Carolina retail portion of all reasonable and prudent costs incurred by the electric public utility to acquire, operate and maintain the acquired plant, as well as reasonable and prudent financing costs and non-fuel operating costs related to capital investments in the acquired plant.

(9) "Rate period" means the period during which the Joint Agency Asset rider established under this rule will be in effect. For each public utility, this period will be the same as the period during which the rider established under Rule R8-55 is in effect, unless otherwise ordered by the Commission.

(10) "Test period" shall be the calendar year that precedes the end of the test period for each electric public utility for purposes of Rule R8-55, unless otherwise ordered by the Commission.

(b) Recovery of Costs.

(1) In determining the amount of the Joint Agency Asset rider, the Commission shall include the following:

i. The financing costs and depreciation and amortization expenses associated with the acquired plant, including the amount paid over book value, levelized over the remaining useful life of the electric generating facilities. The remaining useful life will be determined at the time of the acquisition.

ii. The financing costs associated with coal inventory and the acquisition costs not included in amounts being levelized in (b)(1)(i), including net nuclear fuel, fuel inventory, and materials and supplies inventory, but excluding construction work in progress.

iii. The estimated non-fuel operating costs for the acquired plant, not recovered through (b)(1)(i), based on the experience of the test period and the costs projected for the next 12 month rate period.

iv. The estimated financing costs and non-fuel operating costs associated with the reasonable and prudent proportional capital investments including allowance for funds used during construction (AFUDC) in the acquired plant that are placed in service subsequent to the acquisition date.

v. Adjustments to reflect changes in the North Carolina retail portion of financing and non-fuel operating costs related to the electric public utility's other used and useful generating facilities owned at the time of the acquisition to properly account for changes in the jurisdictional allocation factors that result from the addition of the joint agency to the load served by those other facilities.

ATTACHMENT A

vi. A Joint Agency Asset rolling recovery factor (Joint Agency Asset RRF) to reflect the under or over recovery balance. The electric public utility will maintain an under or over recovery balance and add to the balance the difference between the reasonable and prudent financing and non-fuel operating costs incurred by the electric public utility during the test period and the revenues to recover these costs during the test period that were actually realized.

vii. Upon request by the electric public utility, the experienced under or over recovery of financing and non-fuel operating costs incurred after the test period and up to thirty (30) days prior to the date of the hearing in its determination of the Joint Agency Asset rider, provided that the reasonableness and prudence of these costs shall be subject to review in the utility’s next annual Joint Agency Asset rider hearing.

(2) In determining cost recovery allocation, the Commission shall utilize the jurisdictional and customer class allocation methodology used in the electric public utility’s most recent general rate case.

(3) Each electric public utility shall utilize deferral accounting for costs considered for recovery through the Joint Agency Asset rider. The balance in the deferral account, net of tax, shall accrue a monthly return at the net-of-tax rate of return, grossed up for income taxes, as approved in the electric public utility’s most recent general rate proceeding.

(4) The provisions of this Rule shall not relieve the Commission of its responsibility to determine the reasonableness and prudence of the cost of capital additions or operating costs incurred related to the acquired plant in a general rate proceeding.

(5) The burden of proof as to the correctness, reasonableness, and prudence of the cost of capital additions or operating costs sought to be included in the Joint Agency Asset rider, including the Joint Agency Asset RRF, shall be on the electric public utility.

(c) Annual Proceeding.

(1) Each year the Commission shall hold a hearing pursuant to G.S. 62-133.14 to establish an annual Joint Agency Asset rider for the applicable electric public utility.

(2) The annual rider hearing will be scheduled as soon as practicable after the hearing held by the Commission for the electric public utility under Rule R8-55. Each electric public utility shall file its application for recovery of costs under this Rule at the same time that it files the information required by Rule R8-55.

(3) After the initial establishment, the Joint Agency Asset rider will remain in effect, subject to annual updates as provided in this rule, until the end of the useful life of

the acquired plant, with any remaining unrecovered costs deferred until the electric public utility's next general rate proceeding.

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(d) Initial Rider.

(1) For the initial filing to establish the Joint Agency Asset rider pursuant to this rule, the electric public utility shall submit an application no later than 60 days after the date of acquisition containing such information as the Commission may require to recover all estimated financing and non-fuel operating costs which the utility expects to incur during the period from the date of acquisition until the effective date of the rates approved by the Commission in the Company's next annual Joint Agency Asset Rider. After hearing, the Commission shall approve an initial Joint Agency Asset rider to the electric public utility's rates.

(2) The initial filing should include a special fuel rider to be implemented on the same date as the initial Joint Agency Asset rider that reflects the estimated fuel savings to be experienced by the utility when the purchased Joint Agency assets are included in the utility's system fuel costs. This special fuel rider is eliminated at the effective date of the implementation of a fuel cost rate per Rule R8-55 which reflects a system fuel costs including the acquired plant assets.

(e) Filing Requirements and Procedure.

(1) The electric public utility filing proposed adjustments to the Joint Agency Asset rider shall submit to the Commission the following information:

i. The deferred balance at the beginning of the test year plus any under or over recovery resulting from the operation of the Joint Agency Asset rider during the test period.

ii. Any rate changes necessary to recover costs forecasted for the rate period.

iii. The weighted average cost of capital as authorized by the Commission in the electric public utility's most recent general rate case, grossed-up for income taxes and Commission regulatory fee, applicable to the test period and rate period, after the initial establishment of the rider. This weighted average cost of capital should be applied to both the remaining acquisition costs and any additional capital investment placed in service made by the electric utility in the acquired electric generating facilities.

iv. Any changes to the customer allocation methodology determined in any general rate proceeding of the electric public utility occurring after the initial establishment of the rider.

v. The acquisition costs of the generating facilities and accumulated depreciation and amortization reserve as of the end of the test period.

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vi. For each of the first ten years of the rider, the total test period fuel savings for the North Carolina retail jurisdiction, by customer class, arising as a result of the electric public utility's acquisition of the acquired plant.

(2) The Commission shall require the electric public utility to file a monthly report, which shall contain such information as may be agreed to by the Public Staff and the electric public utility and approved by the Commission.

(f) The electric public utility shall publish notice for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least 30 days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-133.14 and setting forth the time and place of hearing.

(g) If the Commission has not issued an Order within 180 days after the electric utility has filed the proposed changes under this rule, then the electric utility may place such proposed changes into effect, subject to later refund of any amount collected plus interest that the Commission might determine to be in excess of the amount ultimately approved by the Commission.

DOCKET NO. P-100, SUB 99
DOCKET NO. P-100, SUB 99a

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. P-100, SUB 99 In the Matter of Quality of Service Objectives for Local Exchange Telephone Companies DOCKET NO. P-100, SUB 99a In the Matter of Quality of Service Reports Pursuant to Rule R9-8	)	ORDER SUSPENDING REPORTING REQUIREMENT SET FORTH IN COMMISSION RULE R9-8(d)

BY THE COMMISSION: On September 8, 2015, the Public Staff filed a motion in these dockets requesting that the Commission issue an order suspending the quarterly compliance reporting required for incumbent local exchange companies (ILECs) and competing local providers (CLPs) pursuant to Commission Rule R9-8(d).

On September 10, 2015, the Commission issued an Order requesting comments on the Public Staff's motion. Initial comments were due by September 23, 2015 and reply comments were due by September 30, 2015. Initial comments were filed by: (1) Barnardsville Telephone Company, Saluda Mountain Telephone Company, and Service Telephone Company (collectively, RiverStreet) and Citizens Telephone Company (Comporium), (RiverStreet and Comporium filed their comments jointly); and (2) MCImetro Access Transmission Services, LLC, d/b/a Verizon Transmission Services LLC (Verizon). No party filed reply comments.

PUBLIC STAFF'S MOTION

In its motion, the Public Staff noted that Commission Rule R9-8, which was adopted by the Commission in 1988, requires all ILECs and CLPs regulated by the Commission to perform and provide service in accordance with fourteen uniform service objectives. The Public Staff stated that in 2000, the Commission added subsection (d) to Rule R9-8 to enable it to better monitor compliance with the Rule. The Public Staff stated that Commission Rule R9-8(d) requires ILECs and CLPs actually providing basic local residential and/or business exchange service within North Carolina[1] to make quarterly filings with the Commission detailing the results of their compliance with ten service objectives outlined in Commission Rule R9-8 as listed in the table below.

[1] Companies not providing basic local residential and/or business exchange service in North Carolina are required to file a letter, in lieu of a report, each quarter specifying why a report does not have to be filed.

Measure No.	Description	Objective
5	Operator "0" answertime	90% or more of calls answered within 10 seconds or ASA of 6 seconds
6	Directory assistance answertime	85% or more of calls answered within 10 seconds or ASA of 6 seconds
7	Business office answertime	ASA of 30 seconds
8	Repair service answertime	ASA of 30 seconds
9	Initial customer trouble reports	4.75 or less per 100 total access lines
10	Repeat reports	1.0 report or less per 100 total access lines
11	Out-of-service troubles cleared within 24 Hours	95% or more
12	Regular service orders completed within 5 working days	90% or more
13	New service installation appointments not met for Company reasons	5% or less
14	New service held orders not completed within 30 days	0.1% or less of total access lines

The Public Staff maintained that over the past fifteen years since imposing the reporting requirement, the Commission has issued various orders modifying the original reporting requirements, with the most recent order being issued on May 13, 2014.

The Public Staff noted that it tabulates the reports filed by ILECs and CLPs and produces a summary that is placed on the Commission's website. The Public Staff stated that this summary gives an indication of those companies that are consistently meeting the various service quality standards, thus providing a quality of service measure that is available to consumers when making a decision concerning a preferred local service provider.

The Public Staff noted that in 2009, the General Assembly enacted G.S. 62-133.5(h), which created a new category of price plan under which ILECs and CLPs could elect to operate. The Public Staff stated that in an Order issued on March 30, 2010, in Docket No. P-100, Sub 165, the Commission determined that ILECs and CLPs opting into regulation under this new category of price plan, referred to as Subsection (h) price plan, were not subject to the service quality requirements in Commission Rule R9-8, including the reporting requirements.

Further, the Public Staff stated that in 2011, the General Assembly enacted G.S. 62-133.5(m), creating yet another category of price plan under which ILECs and CLPs could elect to operate. The Public Staff noted that in an Order issued on November 22, 2011, in Docket No. P-100, Sub 165a, the Commission determined that ILECs and CLPs opting into this price plan category, referred to as Subsection (m) price plans, were not subject to the service quality requirements in Commission Rule R9-8, including the reporting requirements.

The Public Staff maintained that, subsequent to the issuance of the Commission Orders regarding Subsection (h) and (m) price plans, many ILECs and CLPs have filed letters with the Commission opting into one of the two price plans. The Public Staff provided a table as shown below which lists those companies that have opted into either a Subsection (h) or a Subsection (m) price plan.

Company	**Classification**
BellSouth Telecommunications, LLC	ILEC
Carolina Telephone and Telegraph Company	ILEC
Central Telephone Company	ILEC
Ellerbe Telephone Company	ILEC
Frontier Communications of the Carolinas Inc.	ILEC
MebTel, Inc.	ILEC
North State Telephone Company	ILEC
Town of Pineville	ILEC
Verizon South, Inc.	ILEC
Windstream Concord Telephone, LLC	ILEC
Windstream Lexcom Communications, LLC	ILEC
Windstream North Carolina, LLC	ILEC
AT&T Corp.	CLP
CenturyLink Communications, LLC	CLP
Crosstel Tandem, Inc.	CLP
dishNET Wireline, L.L.C.	CLP
ETC Communications, LLC	CLP
Frontier Communications of America, Inc.	CLP
North State Communications Advanced Services, LLC	CLP
Onvoy, Inc.	CLP
Rosebud Telephone, LLC	CLP
SCTG Communications	CLP
Smithville Telecom, Inc.	CLP
Teleport Communications America, LLC	CLP
Time Warner Cable Information Services, Inc.	CLP
Tri-County Communications, Inc.	CLP
Wide Voice, LLC	CLP

The Public Staff noted that of the 16 ILECs, Barnardsville Telephone Company, Citizens Telephone Company, Saluda Mountain Telephone Company, and Service Telephone Company are the only ILECs still subject to the reporting requirements of Commission Rule R9-8(d). The

Public Staff maintained that, thus, the major ILECs operating in North Carolina are currently exempt from Rule R9-8(d).

In addition, the Public Staff noted that 15 CLPs have chosen price plans that are exempt from Rule R9-8(d) as well, and many of the CLPs still subject to the reporting requirements of Rule R9-8(d) are reselling the services of an underlying carrier. The Public Staff asserted that the continued reporting by local resellers whose service quality results depend on their underlying carrier does not appear to provide useful information to the Commission or to consumers.

In summary, the Public Staff noted that the adoption of Subsection (h) and (m) price plan regulation by local providers has greatly diminished the purpose and effect of the reporting requirements in Commission Rule R-9-8(d). The Public Staff asserted that instead of modifying or repealing subsection (d), however, the Public Staff believes the public interest would be served by simply suspending the reporting requirements indefinitely. Therefore, the Public Staff requested that the Commission suspend until further order the quarterly reporting requirements in Commission Rule R9-8(d) as to those few ILECs and CLPs still subject to Rule R9-8.

INITIAL COMMENTS

RiverStreet and Comporium stated that they support the Public Staff's motion and join in requesting that the Commission suspend those reporting requirements. RiverStreet and Comporium stated that, as noted by the Public Staff, they are the only ILECs that are still subject to the reporting requirements set forth in Commission Rule R9-8(d). RiverStreet and Comporium maintained that by virtue of their election of Subsection (h) or Subsection (m) price plans, all of the other ILECs operating in North Carolina have exempted themselves from Rule R9-8(d).

RiverStreet and Comporium asserted that Rule R9-8(d) no longer effectively serves its underlying purpose. RiverStreet and Comporium maintained that suspending these requirements for the few carriers that still provide these reports will conserve the time and resources of those carriers, the Public Staff, and the Commission. RiverStreet and Comporium stated that they agree that the relief requested by the Public Staff is in the public interest, and therefore, they requested that the Commission grant the Public Staff's motion.

Verizon stated that it supports the Public Staff's motion. Verizon maintained that, as the Public Staff noted, many local providers are now exempt from the reporting requirements in Rule R9-8(d), which means the rule no longer effectively serves its underlying purpose. Verizon asserted that suspending these requirements for the carriers that still provide these reports would conserve the time and resources of those carriers, the Public Staff, and the Commission. Verizon asserted that the requested relief therefore is in the public interest and that the Public Staff's motion should be granted.

REPLY COMMENTS

No party filed reply comments.

DISCUSSION AND CONCLUSIONS

As noted by the Public Staff in its motion and the comments of the parties, many local providers are currently exempt from Rule R9-8, including the reporting requirements specified in Rule R9-8(d) due to their election of either a Subsection (h) or Subsection (m) price plan. After reviewing the record on this matter, the Commission agrees with the Public Staff and the commenting parties that Rule R9-8(d) no longer effectively serves its underlying purpose. Further, the Commission agrees with RiverStreet, Comporium, and Verizon that suspending the Rule R9-8(d) reporting requirements would conserve the time and resources of the affected carriers, the Public Staff, and the Commission. Therefore, the Commission finds and concludes that it is appropriate to grant the Public Staff's motion, thereby suspending until further order the quarterly reporting requirements outlined in Commission Rule R9-8(d), effective the date of this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the ___16th___ day of October, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Telecommunications Relay Service (TRS), Relay North Carolina	)))	ORDER DECREASING THE TELECOMMUNICATIONS RELAY SERVICE SURCHARGE

BY THE COMMISSION: On July 23, 2015, the North Carolina Department of Health and Human Services (DHHS) filed a petition requesting that the Commission approve a decrease in the monthly Telecommunications Relay Service (TRS) surcharge pursuant to G.S. 62-157(b) and (c) from $0.14 to $0.10. TRS enables an individual with a hearing or speech disability to communicate by telephone with a person without such a disability. G.S. 62-157(b) and (c) direct the Commission to require local service providers to impose a monthly surcharge (set by the Commission) on qualified access lines to fund the implementation and operation of a relay service and an equipment distribution program, including a "reasonable margin for reserve."[1] The relay service and equipment distribution service comprise the Telecommunications Resources Program (TRP), which is administered by the Division of Services for the Deaf and Hard of Hearing, a division of DHHS. G.S. 62-157 provides that the funds from the surcharge on access lines are available to DHHS to operate and promote the service. In addition to funding from access lines, TRP receives funding through a surcharge pursuant to G.S. 62-157(i), which is collected by wireless providers and remitted to the Wireless 911 Board, which, in turn, remits the funds to DHHS. Under G.S. 62-157(i), the amount of the wireless surcharge is the same as the access line surcharge set by the Commission.

The Commission set the current surcharge by Order dated January 29, 2013, in which the Commission approved an increase in the surcharge to the current rate of $0.14 per access line.

DHHS stated in its petition that the reserve margin, as of the date of its filing, is approximately $6.2 million above the $6.5 million set by the Commission, due to actual expenditures being less than had been projected. In addition, DHHS projects that, under the current surcharge, TRP will continue to experience an increase of revenues versus expenditures, thus resulting in the continuing increase in the reserve over the authorized margin. DHHS requested that the surcharge be decreased to $0.10 to allow continued operations and reduce the reserve to the required amount.

On July 31, 2015, the Commission issued an *Order Seeking Comments Regarding Surcharge Decrease* in which it requested interested parties to file comments regarding the proposed reduction in the TRS surcharge as requested by DHHS. No comments were filed.

The Public Staff presented this matter at the Commission's Regular Staff Conference on September 21, 2015. The Public Staff stated that it has reviewed the petition and that based on an analysis of current and projected expenditures and of projected access line and wireless line growth, the Public Staff believes that the $0.14 will result in continued growth of the excess over

[1] The current reserve margin of $6.5 million was approved by the Commission on July 7, 2010.

the $6.5 million reserve margin set by the Commission, and recommended approval of the decrease to $0.10, as requested by DHHS.

However, the Public Staff noted that time between issuance of a Commission order and DHHS's proposed implementation date of November 1, 2015, was limited. Therefore, the Public Staff recommends that the effective date be set for December 1, 2015, to ensure carriers have sufficient time to implement the rate change.

Based on the foregoing, and entire record in this matter, the Commission is of the opinion that the TRS surcharge should be decreased as requested by DHHS effective December 1, 2015, and that notice should be given to customers of this decrease.

IT IS, THEREFORE, ORDERED as follows:

1. That the monthly TRS surcharge shall be decreased from $0.14 per access line to $0.10 per access line effective for bills issued on or after December 1, 2015. The decrease shall be reflected on customers' bills issued on or after December 1, 2015.

2. That the bill message/insert as set forth in Appendix A shall appear on all customers' bills issued in the billing cycle immediately prior to the December 1, 2015 increase.

3. That DHHS shall revise the TRS surcharge remittance form to reflect the decrease in the surcharge and shall post the revised form on the Telecommunications Resource Program website so as to make it available for downloading.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of September, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner Susan W. Rabon did not participate in this decision.

APPENDIX A

NOTICE OF TELECOMMUNICATIONS RELAY SERVICE (TRS)
SURCHARGE DECREASE

Effective with telephone bills issued on or after December 1, 2015, the Telecommunications Relay Service (TRS) surcharge is $0.10 per access line, per month. On September 21, 2015, the North Carolina Utilities Commission authorized a decrease in the monthly TRS surcharge amount from $0.14 to $0.10 to maintain adequate funding for Division of Services for the Deaf and Hard of Hearing (DSDHH), including the Telecommunications Resource Program

(TRP) and the Regional Resource Centers within DSDHH. TRP is a program within the North Carolina Department of Health and Human Services consisting of a telecommunications relay service that enables persons with hearing, speech, and vision impairments to communicate with others by telephone and an equipment distribution program. Regional Resource Centers provide a wide spectrum of services, including: (1) advocacy, consultation, workshops and training on a wide variety of topics pertaining to hearing loss; (2) communication support; (3) information and referral services; (4) assistance with selection, application for and set-up of equipment, training, and technical assistance as part of the equipment distribution service; and (5) outreach regarding available resources.

DOCKET NO. P-100, SUB 133K

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
CenturyLink's Petition for Relief from	)	ORDER GRANTING CENTURYLINK'S
Interim Performance Measurement	)	MOTION TO WITHDRAW PETITION
Plan Obligations Adopted in Docket	)	WITHOUT PREJUDICE
No. P-100, Sub 133K	)	

BY THE CHAIRMAN: On March 4, 2015, Carolina Telephone and Telegraph Company LLC d/b/a CenturyLink and Central Telephone Company d/b/a CenturyLink (CenturyLink), filed a Petition requesting relief as to CenturyLink's interim, yet long-standing, obligations related to its performance plans. Specifically, CenturyLink requested that the Commission eliminate all OSS performance reporting requirements for CenturyLink, including its OSS performance data collection efforts.

On March 4, 2015, the Commission issued an Order requesting that the Public Staff, the Attorney General, ILECs, CLPs, and/or any other party file comments about CenturyLink's request that it be relieved of all OSS performance reporting requirements by March 26, 2015. CenturyLink was required to file reply comments by April 16, 2015.

On March 26, 2015, the Commission granted the Public Staff's motion to extend the time to file initial comments from March 26, 2015 until April 2, 2015, and reply comments from April 16, 2015 until April 23, 2015.

On April 2, 2015, the Competitive Carriers of the South (CompSouth) and the North Carolina Cable Telecommunications Association (NCCTA) each filed comments opposing CenturyLink's request to be relieved of its OSS performance reporting requirements. The Public Staff also filed comments on that date.

The Public Staff did not take a position on the merits of CenturyLink's request in its comments. Instead, it proposed that the Public Staff, CenturyLink, and interested Competing Local Providers (CLPs) "closely examine the current requirements and determine whether there are modifications that could be made that would allow CLPs to receive sufficient information to ensure that they are receiving nondiscriminatory treatment, while reducing the cost and burden on CenturyLink." (Public Staff Comments).

On April 21, 2015, CenturyLink filed a Motion to Withdraw Petition (Motion). In support of the Motion, CenturyLink noted that, in view of the concerns identified in the filings of CompSouth and NCCTA, it intended to more fully examine its OSS performance requirements and to engage those parties, as well as the Public Staff, in an effort to determine if the parties can agree on modifications of the current requirements which will address CenturyLink's concerns while still providing information which will address CompSouth's and NCCTA's concerns. Further, CenturyLink noted that it would continue to report the required OSS performance information in the same manner as it reports that information today.

CenturyLink thereafter requested that the Commission permit it to withdraw the petition without prejudice to its ability to refile it in the future or, in the alternative, if the Commission chooses to deny the Motion, that the Commission extends the time for CenturyLink to file reply comments for seven days from the issue date of the order.

After carefully considering the Motion and the record proper, the Chairman finds that good cause exists to grant CenturyLink's Motion to withdraw the petition without prejudice.[1]

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _22nd_ day of April, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

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[1] Since the Commission has granted CenturyLink's motion to withdraw the petition without prejudice, there is no need to address CenturyLink's alternative request that the Commission extend its time to file reply comments.

DOCKET NO. P-100, SUB 170

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Tariff Filings Made by Local Exchange Carriers in Compliance with the Federal Communications Commission's Connect America Fund Order	)))	ORDER GRANTING THE PUBLIC STAFF'S MOTION WITH AN EXTENSION OF TIME FOR FILINGS

BY THE COMMISSION: On June 9, 2015, the Public Staff filed a Motion for Order Requiring Filing of Information Regarding July 1, 2015, Access Rate Changes.

In its Motion, the Public Staff requested that the Commission order certain local exchange carriers to make certain filings showing their compliance with the fourth set of intrastate access rate changes, effective July 1, 2015, mandated by the Federal Communications Commission's (FCC's) November 18, 2011 Universal Service Fund (USF) / Intercarrier Compensation (ICC) Transformation Order by no later than June 16, 2015.

The Public Staff further noted that it has reviewed last year's responses and compiled a list of carriers as reflected in Appendix A to its Motion that the Public Staff believes should make an appropriate filing regarding their 2015 switched access rate changes. The Public Staff stated that, additionally, any carrier that is not listed in Appendix A, but whose status has changed from last year should also be required to make an appropriate filing.

On June 11, 2015, the Commission issued an Order Requesting Comments on the Public Staff's Motion. No party filed initial comments on the Public Staff's Motion.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission finds it appropriate to grant the Public Staff's Motion, however, carriers shall have until June 23, 2015 to make the required filings.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _17th_ day of June, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-22, SUB 526

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Costs Adjustments for Electric Utilities	)))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Monday, November 2, 2015, beginning at 1:30 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioner Bryan E. Beatty, Commissioner ToNola D. Brown-Bland, Commissioner Don M. Bailey, Commissioner Jerry C. Dockham, and Commissioner James G. Patterson

APPEARANCES:

For Carolina Utility Customers Association, Inc.

Robert F. Page, Crisp, Page & Currin, L.L.P., 4010 Barrett Drive, Suite 205, Raleigh, NC 27609

For Dominion North Carolina Power:

Mary Lynne Grigg, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

Horace P. Payne, Jr., Dominion Resources Services, Inc., 120 Tredegar Street, Riverside 2, Richmond, Virginia 23219

For the Public Staff:

Lucy E. Edmondson, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On August 19, 2015, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP or Company), filed its application for a fuel charge adjustment, along with accompanying testimony and exhibits, pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities (Application).[1] The Application was accompanied by the testimony and exhibits of Edward J.

[1] Pursuant to G.S. 62-133.2(a3), DNCP is not eligible to recover non-fuel (but still fuel-related) costs through the annual rate adjustments authorized pursuant to G.S. 62-133.2, except for certain costs authorized by G.S. 62-133.2(a1)(6), which DNCP did not incur during the test period and is not projected to incur during the rate

Anderson, Regulatory Advisor; Kelly K. Conway, Director of Accounting for Dominion Generation; Bruce E. Petrie, Manager of Generation System Planning; Tom A. Brookmire, Manager of Nuclear Fuel Procurement; Gregory A. Workman, Director - Fuels; and Alan L. Meekins, Director - Electric Market Operations.

On August 26, 2015, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice.

Petitions to intervene were filed by the Carolina Industrial Group for Fair Utility Rates I (CIGFUR) on August 24, 2015, Nucor Steel-Hertford (Nucor) on August 27, 2015, and Carolina Utility Customers Association, Inc., on September 2, 2015. These petitions were granted by Orders dated August 27, 2015, September 2, 2015, and September 3, 2015, respectively. The Public Staff's participation and intervention was recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

The Company filed its Affidavit of Publication on October 14, 2015. On October 16, 2015, the Public Staff filed the affidavits of Jay B. Lucas, Engineer, Public Staff Electric Division; and Darlene P. Peedin, Supervisor, Electric Section, Public Staff Accounting Division.

On October 20, 2015, DNCP and the Public Staff filed a joint motion requesting that the Commission issue an order excusing the appearance of all witnesses at the hearing. The Commission granted the motion by Order dated October 21, 2015.

The matter came on for evidentiary hearing on November 2, 2015, as scheduled. No public witnesses appeared at the hearing. The parties waived cross-examination of all witnesses, and all of their testimony was received into evidence as if given orally from the stand.

Based upon the verified application, the evidence received at the hearing, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. DNCP is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. DNCP is lawfully before this Commission based on its application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the twelve months ended June 30, 2015.

3. The Company's fuel procurement and power purchasing practices during the test period were reasonable and prudent.

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period. Therefore, throughout this Order, the costs being considered for recovery shall be termed "fuel costs," and the proceeding shall be termed the "fuel charge proceeding."

4. The test period per book system sales are 84,334,207,510 kilowatt-hours (kWh).

5. The test period per book system generation is 84,630,345 megawatt-hours (MWh), which includes various types of generation as follows:

Generation Types	MWh
Nuclear	27,639,833
Coal (including wood and natural gas steam)	25,151,296
Heavy Oil	468,031
Combined Cycle and Combustion Turbine	16,907,346
Hydro – Conventional and Pumped Storage	3,005,995
Net Power Transactions	14,297,007
Less: Energy for Pumping	(2,839,163)

6. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

7. The nuclear capacity factor appropriate for use in this proceeding is 94.10%, which is the estimated nuclear capacity factor for the 12 months beginning January 1, 2016.

8. The adjusted test period system sales for use in this proceeding are 82,842,129,429 kWh.

9. The adjusted test period system generation for use in this proceeding is 83,066,285 MWh, which is categorized as follows:

Generation Types	MWh
Nuclear	27,717,019
Coal (including wood and natural gas steam)	24,438,338
Heavy Oil	454,784
Combined Cycle and Combustion Turbine	16,428,087
Hydro – Conventional and Pumped Storage	3,005,995
Net Power Transactions	13,861,225
Less: Energy for Pumping	(2,839,163)

10. Only actual fuel costs associated with power purchases can be recovered by DNCP through its fuel charge proceeding and, therefore, a marketer percentage has to be derived to serve as a proxy for fuel costs when actual fuel costs are not available. In this proceeding, a marketer percentage of 85%, to be applied to appropriately determine purchase power expense, should continue to be used.

11. The adjusted test period system fuel expense for use in this proceeding is $1,883,772,194.

12. The proper fuel factors for Rider A for this proceeding, including the regulatory fee, are as follows:

Customer Class	Rider A
Residential	(0.154) ¢/kWh
SGS & PA	(0.154) ¢/kWh
LGS	(0.149) ¢/kWh
NS	(0.148) ¢/kWh
6VP	(0.149) ¢/kWh
Outdoor Lighting	(0.154) ¢/kWh
Traffic	(0.154) ¢/kWh

13. The study submitted by the Company to demonstrate that it has complied with Ordering Paragraph 1(e) of the Commission's *Order Approving Transfer with Conditions* issued April 19, 2005, in Docket No. E-22, Sub 418 (PJM Order), is reasonable for use in this proceeding.

14. The appropriate North Carolina test period jurisdictional fuel expense undercollection is $1,982,942 and the adjusted North Carolina jurisdictional test period sales are 4,385,892,621 kWh.

15. The appropriate Experience Modification Factors (EMF or Rider B) for this proceeding, including the regulatory fee, are as follows:

Customer Class	EMF Billing Factor
Residential	0.045 ¢/kWh
SGS & PA	0.045 ¢/kWh
LGS	0.045 ¢/kWh
NS	0.044 ¢/kWh
6VP	0.044 ¢/kWh
Outdoor Lighting	0.045 ¢/kWh
Traffic	0.045 ¢/kWh

16. It is appropriate to implement the second step of the Company's mitigation proposal to have rates established in this proceeding to recover the remaining 50% of the 2014 test period fuel expense undercollection in the 2016 fuel year, without interest. The appropriate fuel expense underrecovery related to the approved mitigation plan is $8,301,335. The appropriate Rider B2 EMF factors, including the current regulatory fee of .00148%, are as follows:

Customer Class	Rider B2 EMF Billing Factor
Residential	0.191 ¢/kWh
SGS & PA	0.191 ¢/kWh
LGS	0.189 ¢/kWh

NS	0.184 ¢/kWh
6VP	0.187 ¢/kWh
Outdoor Lighting	0.191 ¢/kWh
Traffic	0.191 ¢/kWh

17. The base fuel component as approved in Docket No. E-22, Sub 479 in the amount of 2.455 ¢/kWh for the Residential class, 2.454 ¢/kWh for the SGS & PA class, 2.432 ¢/kWh for the LGS class, 2.360 ¢/kWh for Schedule NS, 2.405 ¢/kWh for 6VP, 2.455 ¢/kWh for Outdoor Lighting, and 2.455 ¢/kWh for Traffic, should be adjusted by Rider A for each class as set forth in Finding of Fact No. 12 and further adjusted by EMF Rider B and Rider B2 increments for each class as set forth in Finding of Fact Nos. 15 and 16, respectively. The final net fuel factors to be billed to DNCP's retail customers during the 2016 fuel charge billing period, including the regulatory fee, are as follows:

Customer Class	Total Net Fuel Factor
Residential	2.537 ¢/kWh
SGS & PA	2.536 ¢/kWh
LGS	2.517 ¢/kWh
Schedule NS	2.440 ¢/kWh
6VP	2.487 ¢/kWh
Outdoor Lighting	2.537 ¢/kWh
Traffic	2.537 ¢/kWh

18. It is appropriate to grant DNCP's request to waive the requirement for it to perform an annual PJM Integration Study; however, the Commission may, upon its own motion or upon a showing of good cause by a party, require DNCP to perform the study in the future.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending June 30 as the test period for DNCP. The Company's filing was based on the 12 months ended June 30, 2015.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every ten years and each time the utility's fuel procurement practices change. The Company's current fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, on December 20, 2013.

In his direct testimony, Company witness Workman discussed commodity prices, the Company's fuel procurement policy, and coal, natural gas, oil, and biomass procurement. He explained that commodity prices (including coal, natural gas, and crude oil) worldwide fell considerably during the test period. Witness Workman described the Company's fossil fuel procurement practices and explained that the Company continues to follow the same procurement practices it has in the past in accordance with its report filed in Docket No. E-100, Sub 47A.

In regard to coal procurement, Witness Workman noted that the Company followed a multi-year plan accomplished primarily through periodic solicitations and secondarily on the open market, allowing the Company to layer in coal contracts of staggered terms and blended prices to mitigate exposure to significant price swings.

Company witness Workman noted that the Company had determined that it was prudent to modify its gas procurement practices to include more firm transportation agreements from diverse locations and for longer terms (terms greater than day-ahead or intra-day) as compared to the current approach of terms of only day-ahead or intra-day. Witness Workman explained that this approach would promote greater certainty of supply and is consistent with the Company's approach to coal procurement. As with coal, the Company will issue periodic solicitations and use the open market to meet its requirements. Further, when appropriate, the Company will use financial hedging instruments to mitigate price volatility. Additionally, DNCP evaluates its diverse portfolio of pipeline and storage contracts and participates in the interstate pipeline capacity release and physical supply markets as well as longer-term, pipeline expansion projects to enhance reliability at a reasonable cost.

Witness Workman pointed out the increasing importance of natural gas as a percentage of the Company's energy requirements. He noted that while during the test period the Company met approximately 20% of its annual energy requirements with natural gas, this percentage is expected to grow to as much as 40% by 2019 as new gas-fired generation becomes operational.

Company witness Workman indicated that the Company used a price hedging program as one way to stabilize fuel rates. Under the Company's Marginal Fuel Hedging Program for natural gas, the Company has hedged using 25% of the forecasted volumes during the summer and winter months in the low load case. In addition, the Company has hedged on-peak power using the forecasted volumes for all twelve months in the low load case. While the Company expects purchased power volumes to decrease over time, the Company plans to continue its financial hedges of a portion of these volumes when beneficial for customers.

DNCP also plans to expand its forward price hedging activity for natural gas from one year up to three years and to increase price hedging levels to a target range of 20% to 50% of forecasted volumes to be purchased in the first year of a three-year period. The Company expects to achieve these targets through the pricing associated with the gas supply and transportation procurement activities as described above, as well as the use of derivative instruments to financially hedge a portion of these volumes.

Witness Workman further testified that the Company procures its No. 2 fuel oil and No. 6 oil requirements on the spot market. Wood chips and other woody material for four biomass-fired plants are procured via long-term contracts, supplemented with short-term contracts, and the Company procures biomass for its Virginia City Hybrid Energy Center (VCHEC) facility via short-term contracts.

With respect to the nuclear fuel market, Company witness Brookmire testified that in the past year prices have remained soft for both the spot and long-term price for uranium and enrichment due to continued demand reductions resulting from delayed returns to operation following the 2011 tsunami and its effects on Japan's nuclear fleet, other reductions in demand worldwide, and the strength of the dollar. However, some decreases in supply have somewhat offset the downward trend in demand. Prices for spot conversion services remain soft, though prices for long-term supply remain higher. Domestic fabrication prices are generally expected to continue to increase. Further, several reactors in Japan are expected to restart in 2015, which may increase prices of front-end components. Witness Brookmire further testified that these changes had not significantly impacted the Company's near-term costs because the current mix of longer-term front-end component contracts has reduced the near-term impact of changes in market prices. In addition, the Company has continued to see the effect of lower prices as older, legacy contracts were replaced with market-based contracts at current lower prices. Witness Brookmire also noted that the Company continues to follow the same nuclear fuel procurement practices as it has in the past, in accordance with its procedures filed in Docket No. E-100, Sub 47A.

No party offered testimony contesting the Company's fuel procurement and power purchasing practices. Based on the foregoing, the Commission concludes that the Company's fuel procurement and power purchasing practices during the test period were reasonable and prudent.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 - 5

The evidence for these findings of fact is contained in the direct testimony and exhibits of DNCP witnesses Anderson and Petrie.

DNCP witness Anderson testified that the Company's test period per book system sales were 84,334,207,510 kWh, and witness Petrie testified that the Company's test period per book system generation was 84,630,345 MWh. Witness Petrie stated that the test period per book system generation is categorized as follows:

Generation Types	MWh
Nuclear	27,639,833
Coal (including wood and natural gas steam)	25,151,296
Heavy Oil	468,031
Combined Cycle and Combustion Turbine	16,907,346
Hydro – Conventional and Pumped Storage	3,005,995
Net Power Transactions	14,297,007
Less Energy for Pumping	(2,839,163)

No other party offered or elicited testimony on the level of test period per book system MWh sales or generation. The Commission thus concludes that the foregoing test period per books levels of sales and generation are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is contained in the testimony of Company witnesses Petrie and Workman.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC) Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Petrie testified that the Company's four nuclear units operated at a system average capacity factor of 94.3% during the test period, which exceeded the five-year industry weighted average capacity factor of 87.8% for the period 2009-2013 for 800 to 999 megawatt (MW) units, as reported by NERC in its latest Generating Availability Report.

Company witness Petrie testified that the Company's generating fleet performed well during the test period winter peak. The January 14, 2014, record demand of 19,785 MW was broken on February 20, 2015 with a new record demand of 21,651 MW.

During the test period, the Company made significant changes to its generation fleet that resulted in fuel benefits. In December 2014, the Company retired the four base load coal-fired units at its Chesapeake Energy Center, which had a combined capacity of 595 MW. Also in December 2014, the Company placed into service its Warren County natural gas-fired combined cycle plant with a capacity of 1,329 MW.

Based upon the evidence in the record, the Commission concludes that DNCP managed its baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is contained in the direct testimony of DNCP witness Petrie and the affidavit of Public Staff witness Lucas.

Company witness Petrie testified in his direct testimony that, for the 12 months ending December 31, 2016, North Anna Unit 1 is projected to operate at a net capacity factor of 90.5%, North Anna Unit 2 is projected to operate at a net capacity factor of 92.2%, Surry Unit 1 is projected to operate at a net capacity factor of 94.0%, and Surry Unit 2 is projected to operate a net capacity factor of 100.2%. Based on this projection, the Company normalized expected nuclear generation and fuel expenses in developing the proposed fuel cost rider. DNCP's projected fuel costs are based on a 94.10% nuclear capacity factor, which is what DNCP anticipates for the twelve months from January 1, 2016, through December 31, 2016, the period the new rates will be in effect.

Based on the foregoing evidence, the Commission concludes that a projected normalized system nuclear capacity factor of 94.10% is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is contained in the direct testimony of DNCP witness Anderson and the affidavit of Public staff witness Lucas.

Witness Anderson testified that he was sponsoring the calculation of the adjustment to the Company's system sales for the twelve months ended June 30, 2015, due to changes in usage, weather normalization, and customer growth, in accordance with Commission Rule R8-55(d)(2). The Company's filing further states that the methodology used for the normalization is the same as adopted by the Commission in Docket No. E-22, Sub 479, the Company's last general rate case. Witness Anderson adjusted total Company sales by (1,492,078,081) kWh. This adjustment is the sum of adjustments for changes in usage, weather normalization, and customer growth. The Public Staff reviewed and accepted these adjustments. No other party offered or elicited testimony on these adjustments.

Based on the foregoing, the Commission concludes that the adjustments for changes in usage, weather normalization, and customer growth are reasonable and appropriate adjustments for use in this proceeding. The adjusted system sales for the twelve months ended June 30, 2015, are 82,842,129,429 kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is contained in the direct testimony of Company witness Petrie.

DNCP witness Petrie presented an adjustment to per book MWh generation for the 12-month period ended June 30, 2015, to incorporate nuclear generation based upon the expected future operating parameters for each unit. Other sources of generation were then normalized, including an adjustment for weather, customer growth, and increased usage. This methodology for normalizing test period generation resulted in an adjusted generation level of 83,066,285 MWh. The Public Staff accepted this adjusted generation level, which includes various types of generation as follows:

Generation Types	MWh
Nuclear	27,717,019
Coal (including wood and natural gas steam)	24,438,338
Heavy Oil	454,784
Combined Cycle and Combustion Turbine	16,428,087
Hydro – Conventional and Pumped Storage	3,005,995
Net Power Transactions	13,861,225
Less Energy for Pumping	(2,839,163)

No other party offered or elicited testimony on the adjusted test period system generation for use in this proceeding. Thus, based on the foregoing, the Commission concludes that the adjusted test period system generation level of 83,066,285 MWh is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the direct testimony of DNCP witness Conway and the affidavit of Public Staff witness Peedin.

Company witness Conway explained that for dispatchable NUGs that do not provide actual fuel costs, the Company continues to include 85% of the reasonable and prudent energy costs in the EMF calculation. She also noted that 85% of the reasonable and prudent energy costs of market-based energy were included in the EMF calculation.

Public Staff witness Peedin explained that during the test period DNCP purchased power through markets administered by PJM Interconnection, LLC (PJM) and from two dispatchable NUGs that did not provide DNCP with the actual fuel costs associated with the purchases. As a result, a proxy marketer percentage was determined and applied to the total energy costs of the purchases. Witness Peedin also explained that the use of a “proxy” has been accepted by this Commission as reasonable in every fuel proceeding since 1997. She explained that the most current marketer percentage was approved by the Commission in the Order Granting General Rate Increase Approving Fuel Charge Adjustment, and Approving Stipulation and Supplemental Agreement (Order), issued in Docket No. E-22, Sub 479, which provided that 85% of the reasonable and prudent energy costs incurred during the fuel charge adjustment proceeding test period are to be recovered through DNCP’s fuel factor. The 85% marketer percentage was to remain in effect until the sooner of DNCP’s next general rate case or the fuel charge adjustment proceeding held in 2015 (with rates effective January 1, 2016).

Witness Peedin stated that the Company did not propose a change to the marketer percentage for this fuel adjustment proceeding and that the Public Staff believes that the continued use of the 85% fuel proxy is reasonable for this fuel adjustment proceeding. The Public Staff recommends that the percentage be reviewed in the context of DNCP’s next general rate case, which is anticipated to be filed in 2016, or its 2016 fuel charge adjustment proceeding, whichever occurs first. No party disputed the use of 85% in this proceeding or the use of actual fuel costs as described by the Company.

Based upon the foregoing, the Commission concludes that it is reasonable to apply an 85% fuel-to-energy percentage to DNCP’s purchases from suppliers that do not provide the Company with actual fuel costs as the proxy for actual fuel costs associated with such purchases in this proceeding, and that the percentage should be reviewed in the context of DNCP’s next general rate case or its 2016 fuel charge adjustment proceeding, whichever occurs first.

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

The evidence for these findings of fact is contained in the direct testimony of Company witnesses Petrie and Anderson, and the affidavit of Public Staff witness Lucas.

Company witness Petrie presented the Company's system fuel expense for the test period and the normalized system fuel expenses projected for the calendar year 2016 rate period of $1,883,772,194. He further testified that the fuel underrecovery experienced by the Company was driven by severe cold weather, particularly during February 2015. He testified that he normalized fuel expenses using a methodology approved in previous North Carolina fuel rate cases. More specifically, the expense rates for nuclear, coal, oil, and NUGs were based on the actual 12-month average expense rates incurred during the test period. The expense rates for natural gas and purchased power were adjusted downward to account for the effect of the abnormally cold weather and resulting gas daily price spikes during the first quarter of 2015. Various other adjustments were made, as itemized in witness Petrie's testimony.

Company witness Anderson presented the Company's calculation of the Fuel Cost Rider A applicable for each North Carolina retail jurisdiction customer class. He first determined the average system fuel factor of 2.277 ¢/kWh, based on system fuel expenses of $1,883,772,194, and system sales of 82,842,129,429, that reflected adjustments for changes in usage, weather normalization, and customer growth. Witness Anderson then used customer class expansion factors to determine the North Carolina retail jurisdictional voltage differentiated prospective fuel factors at the sales level applicable to each customer class. For each customer class, the appropriate factor was then compared to its corresponding base fuel factor to determine the appropriate Fuel Cost Rider A rate. In his affidavit, Public Staff witness Lucas stated that, based upon its investigation, the Public Staff determined that the projected fuel costs and the prospective components of the total fuel factor (Rider A), as set forth in the application, were calculated appropriately for this proceeding.

No other party offered or elicited testimony on the adjusted test period system fuel expense for use in this proceeding. Based upon the foregoing, the Commission concludes that the appropriate level of fuel expenses to be used to set the prospective, or forward-looking, fuel factor in this proceeding is $1,883,772,194.

The Commission further concludes that the proper fuel factors (Rider A) for use in this proceeding, including the regulatory fee, are as follows:

Customer Class	Rider A
Residential	(0.154) ¢/kWh
SGS & PA	(0.154) ¢/kWh
LGS	(0.149) ¢/kWh
NS	(0.148) ¢/kWh
6VP	(0.149) ¢/kWh
Outdoor Lighting	(0.154) ¢/kWh
Traffic	(0.154) ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is contained in the direct testimony of DNCP witness Meekins and the affidavit of Public Staff witness Lucas.

Company witness Meekins testified that pursuant to the Commission's conditional approval of DNCP's joining PJM on April 19, 2005, in Docket No. E-22, Sub 418 (Sub 418), the Company has been required to show the impact of its integration into PJM on the Company's North Carolina fuel cost, and therefore has filed a PJM Integration Study in the current proceeding. He stated that the study submitted for the 12-month period ending June 30, 2015, shows that the Company's purchase of economy energy from the PJM market was economical and beneficial compared to how the Company would have operated as a stand-alone entity. The Company has been able to purchase and import significantly more energy from the PJM market than it was historically able to do as an independent Balancing Authority.

Public Staff witness Lucas noted in his affidavit that he reviewed the PJM Integration Study filed by the Company in this proceeding and accepts its finding that for the test period, DNCP's fuel costs incurred as a member of PJM are less than the fuel costs that would have been incurred if DNCP had not joined PJM.

Based on Witness Meekins' testimony and Witness Lucas' affidavit, the Commission concludes that no adjustment is necessary to account for the Company's integration into PJM.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14 -16

The evidence supporting these findings of fact is contained in the direct testimony and exhibits of DNCP witnesses Anderson and Petrie and the affidavits of Public Staff witnesses Lucas and Peedin.

The Company testified that severe cold weather and high commodity and power prices during the first quarter of 2015 resulted in an underrecovery of fuel costs of $1,982,942. To determine the EMF (Rider B), Company witness Anderson divided this fuel costs underrecovery by the adjusted jurisdictional test period sales of 4,385,892,62 kWh. He then used customer class expansion factors to differentiate the uniform factor by voltage to determine the North Carolina retail jurisdictional voltage differentiated EMF fuel factors at the sales level applicable to each customer class. The Public Staff agreed with the Company's calculations of test period fuel costs and adjusted sales.

Based upon the findings and conclusion herein, the Commission concludes that the appropriate North Carolina test period jurisdictional fuel expense undercollection is $1,982,942 and that the adjusted North Carolina jurisdictional test period sales are 4,385,892,621 kWh for computing the EMF (Rider B).

In the 2014 fuel charge proceeding in Docket No. E-22, Sub 515, the Commission found that it was appropriate to accept the Company's mitigation proposal to have rates established in the 2014 proceeding to recover 50% of the test period fuel expense undercollection in the 2015 fuel year and 50% in the 2016 fuel year, without interest. In his Exhibits, Company witness Anderson set forth the appropriate fuel expense underrecovery related to the approved mitigation plan in the amount of $8,301,335, which will be divided by the North Carolina jurisdictional test period sales of 4,385,892,621 kWh to determine the EMF Rider B2. Witness Anderson then used customer class expansion factors to differentiate the uniform factor by voltage to determine the North Carolina retail jurisdictional voltage differentiated EMF Rider B2 fuel factors at the sales level applicable to each customer class. The Commission concludes that it is appropriate to implement the second step of this mitigation proposal EMF Rider B2 in this docket.

The appropriate Experience Modification Factors (EMF) (Rider B) for this proceeding, including the regulatory fee, are as follows:

Customer Class	EMF Billing Factor
Residential	0.045 ¢/kWh
SGS & PA	0.045 ¢/kWh
LGS	0.045 ¢/kWh
NS	0.044 ¢/kWh
6VP	0.044 ¢/kWh
Outdoor Lighting	0.045 ¢/kWh
Traffic	0.045 ¢/kWh

The appropriate Experience Modification Factors (EMF) (Rider B2) for this proceeding, including the current regulatory fee of .00148%, are as follows:

Customer Class	EMF Billing Factor
Residential	0.191 ¢/kWh
SGS & PA	0.191 ¢/kWh
LGS	0.189 ¢/kWh
NS	0.184 ¢/kWh
6VP	0.187 ¢/kWh
Outdoor Lighting	0.191 ¢/kWh
Traffic	0.191 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is cumulative and is contained in the direct testimony and exhibits of DNCP witnesses Anderson, Petrie, Conway, Brookmire, Workman, and Meekins, and the affidavits of Public Staff witnesses Lucas and Peedin.

Based upon the foregoing findings and conclusions, the Commission finds and concludes that the final net fuel factors (¢/kWh) are determined as follows (with Regulatory Fee):

Customer Class	Total Net Fuel Factor
Residential	2.537 ¢/kWh
SGS & PA	2.536 ¢/kWh
LGS	2.517 ¢/kWh
Schedule NS	2.440 ¢/kWh
6VP	2.487 ¢/kWh
Outdoor Lighting	2.537 ¢/kWh
Traffic	2.537 ¢/kWh

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is contained in the direct testimony of DNCP witness Meekins and the affidavit of Public Staff witness Lucas.

Paragraph 1 of the Sub 418 Order states that "Dominion's North Carolina retail ratepayers shall be held harmless from all direct and indirect effects and costs, either related to operations, quality of service, reliability, or rates, arising from its integration with PJM . . ." The Commission stated that this condition shall "remain in effect for a period of not less than ten years from the date of Dominion's integration into PJM and shall continue thereafter indefinitely and until further Order of the Commission." In Docket No. E-22, Sub 428, DNCP's 2005 fuel charge adjustment proceeding, the Commission ordered DNCP to perform a study to determine what fuel costs would have been incurred had it not joined PJM beginning with the next fuel proceeding (PJM Integration Study). Accordingly, beginning in 2006, DNCP has submitted a PJM Integration Study as part of its fuel charge adjustment application in each of its annual fuel dockets.

On June 5, 2015, in Sub 418, DNCP filed a Petition for Relief from the PJM Integration Study Requirement. DNCP stated that the PJM Integration Study has consistently demonstrated that DNCP's integration into PJM has provided significant system benefits through access to larger quantities of less expensive generation than would have been available had DNCP remained an independent entity. On July 21, 2015, the Public Staff filed a Notice of Agreement between DNCP, Nucor, and the Public Staff under which DNCP would file the PJM Integration Study in this proceeding, and these parties would further discuss the relevance of the study and make recommendations whether DNCP should be relieved from conducting the study in future fuel charge proceedings. The Commission approved this agreement by Order issued August 14, 2015.

Company witness Meekins testified that the PJM Integration Studies have consistently shown that ratepayers have benefited from the Company's integration into PJM. He pointed out that it has become difficult after ten years to determine what fuel costs the Company would have incurred without participating in PJM and proposed that a better analysis would be an evaluation of whether the Company has operated in a prudent manner, as is already done, such as reviewing power plant performance measures, evaluating customer service metrics, analyzing fuel procurement decisions, and conducting financial audits. Witness Meekins also pointed out that PJM has an independent market monitor who evaluates the overall competitiveness of the operation of PJM's multiple markets and who produces multiple analytical reports throughout the year that address the efficiency and operation of the markets.

Witness Lucas stated in his affidavit that based on the results of all ten annual studies, the Public Staff believes the Company has sufficiently demonstrated that the results of future studies would continue to show that DNCP's annual fuel costs incurred as a member of PJM are likely to be less than the annual fuel costs that would have been incurred had it not joined PJM. Thus, the Public Staff did not oppose waiving the requirement for an annual PJM Integration Study, provided that the Commission reserved its right to require DNCP to perform the study in the future upon its own motion, or for good cause shown by a party. Further, the Public Staff noted that DNCP remains fully obligated to comply with Sub 418 Condition 1(e), until relieved of that requirement by the Commission.

The Commission finds and concludes that DNCP is no longer required to perform an annual PJM Integration Study, but may be required in the future to perform the study upon order of the Commission. Further, Sub 418 Condition 1(e) remains in full force and effect.

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on and after January 1, 2016, DNCP shall implement a Rider A decrement as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 11 and 12 above;

2. That an EMF Rider increment (Rider B) as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 14 -16 above, shall be instituted and remain in effect for usage from January 1, 2016, through December 31, 2016;

3. That an EMF Rider increment (Rider B2) related to the mitigation plan as approved and set forth in the Evidence and Conclusions for Findings of Fact Nos. 14-16 above, shall be instituted and remain in effect for usage from January 1, 2016, through December 31, 2016;

4. That DNCP shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustments approved herein no later than five working days from the date of receipt of this Order;

5. That DNCP shall work with the Public Staff to prepare a joint proposed Notice to Customers of the rate adjustments ordered by the Commission in Docket Nos. E-22 Subs 524, 525, and 526, and the Company shall file such proposed notice for Commission approval as soon as practicable, and

6. That, with respect to the study required to determine compliance with Ordering Paragraph 1(e) of the PJM Order, DNCP shall not be required to perform and file further PJM Integration Studies unless directed by the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the _8th_ day of December, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-7, SUB 1072

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Cost Adjustments for Electric Utilities	))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, June 2, 2015, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioner Bryan E. Beatty, Commissioner ToNola D. Brown-Bland, Commissioner Don M. Bailey, Commissioner Jerry C. Dockham, and Commissioner James G. Patterson

APPEARANCES:

For Duke Energy Carolinas, LLC:

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolina Industrial Group for Fair Utility Rates III:

Adam Olls, Bailey & Dixon, L.L.P., 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, L.L.P., 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For North Carolina Sustainable Energy Association:

Peter H. Ledford, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Dianna W. Downey, Staff Attorney, Public Staff, North Carolina Utilities Commission, 430 N. Salisbury Street, 4326 MSC, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On March 4, 2015, Duke Energy Carolinas, LLC (Duke Energy Carolinas, DEC, or the Company), filed an application pursuant to G.S. 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Kim H. Smith, Swati V. Daji, Joseph A. Miller, Jr., T. Preston Gillespie, Jr., and David C. Culp.

Petitions to intervene were filed by the Carolina Industrial Group for Fair Utility Rates III (CIGFUR III) on March 5, 2015, by the North Carolina Sustainable Energy Association (NCSEA) on March 17, 2015, and by the Carolina Utility Customers Association, Inc. (CUCA) on March 23, 2015. The Commission granted these three petitions to intervene by separate orders issued on March 24, 2015.

On March 12, 2015, the Commission entered an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. That Order provided that direct testimony of intervenors should be filed on May 18, 2015, that rebuttal testimony should be filed on May 28, 2015, and that a hearing on this matter would be held on June 2, 2015.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On May 12, 2015, DEC filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

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On May 18, 2015, the Public Staff made a verbal request that all intervenors be granted a one day extension of time to May 19, 2015, to file testimony, and on May 19, 2015, the Commission granted the motion, extending the time for filing Public Staff and intervenor testimony to May 19, 2015.

On May 19, 2015, the Public Staff filed the affidavits of Darlene P. Peedin and Jay B. Lucas.

On May 21, 2015, DEC and the Public Staff filed a motion requesting that all witnesses be excused from appearance at the evidentiary hearing. On May 27, 2015, the Commission granted the motion, excusing DEC witnesses Smith, Daji, Miller, Gillespie, and Culp, and Public Staff witnesses Peedin and Lucas from appearing at the evidentiary hearing.

The case came on for hearing as scheduled on June 2, 2015. The prefiled direct testimony of DEC's witnesses and the prefiled affidavits and appendices of the Public Staff's witnesses were received into evidence. Two exhibits offered by NCSEA were received into evidence by stipulation of the parties. No other party presented witnesses, and no public witnesses appeared at the hearing.

The Public Staff and DEC filed a joint proposed order and NCSEA filed a brief on July 2, 2015.

Based upon the Company's verified application, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Carolinas is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. Duke Energy Carolinas is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended December 31, 2014 (test period).

3. In its application and direct testimony in this proceeding, DEC requested a total decrease of $15.3 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEC included Experience Modification Factor (EMF) riders to take into account fuel and fuel-related cost under-recoveries and over-recoveries experienced during the test period, with an overall under-recovery of approximately $10.0 million. Interest applicable to the over-recovery was $60,883.

4. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

5. The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

6. The Company's merger-related fuel savings for the test period as reported in Schedule 11 of the Company's Merger Fuel-Related Savings Report are reasonable.

7. The test period per book system sales are 84,869,637 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 92,394,459 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	31,596,676
Natural Gas, Oil and Biomass	7,878,015
Nuclear	42,380,803
Hydro – Conventional	1,916,588
Hydro Pumped Storage	(732,113)
Solar DG	13,175
Purchased Power – subject to economic dispatch or curtailment	7,200,567
Other Purchased Power	1,393,722

Catawba Interchange	747,026
Total Net Generation	92,394,459

8. The appropriate nuclear capacity factor for use in this proceeding is 93.56%.

9. The N.C. retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 57,252,194 MWh. The adjusted N.C. retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	21,274,670
General Service/Lighting	23,163,092
Industrial	12,814,433
Total	57,252,194[1]

10. The projected billing period (September 2015-August 2016) sales for use in this proceeding are 86,360,640 MWh on a system basis and 57,374,468 MWh on a N.C. retail basis. The projected billing period N.C. retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,436,638
General Service/Lighting	23,280,005
Industrial	12,657,825
Total	57,374,468

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 93,046,731 MWh and is categorized as follows:

Generation Type	MWh
Coal	32,149,466
Gas Combustion Turbine (CT) and Combined Cycle (CC)	8,963,548
Nuclear	44,609,541
Hydro	1,694,430
Net Pumped Storage Hydro	(721,819)
Solar Distributed Generation (DG)	13,544
Purchased Power	6,338,021
Total	93,046,731

12. The appropriate fuel and fuel-related prices and expenses for use in this proceeding to determine projected system fuel expense are as follows:

[1] Rounding difference of 1.

A. The coal fuel price is $32.413/MWh.

B. The gas CT and CC fuel price is $33.16/MWh.

C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $44,250,039.

D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.369/MWh.

E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $208,963,940.

F. System fuel expense recovered through intersystem sales is $24,886,424.

G. The system avoided fuel benefit related to solar distributed generation is $194,114.

13. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,230,584,963.

14. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $9,980,917, consisting of an under-recovery for the residential and general service/lighting classes of $6,335,555 and $4,010,658, respectively, and an over-recovery for the industrial customer class of $365,295. The over-collection resulted in interest of $60,883 for the industrial class.

15. The decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1051, should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

16. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 2.0884¢/kilowatt-hour (kWh) for the Residential class; 2.1578¢/kWh for the General Service/Lighting class; and 2.2153¢/kWh for the Industrial class.

17. The appropriate increment/(decrement) EMFs established in this proceeding, excluding the regulatory fee, are as follows: 0.0298¢/kWh for the Residential class; 0.0173¢/kWh for the General Service/Lighting class; and (0.0029)¢/kWh for the Industrial class.

18. The appropriate EMF interest decrement established in this proceeding, excluding the regulatory fee, is 0.0005¢/kWh for the Industrial class.

19. The total net fuel and fuel-related costs factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 2.1182¢/kWh for the Residential class; 2.1751¢/kWh for the General Service/Lighting class; and 2.2119¢/kWh for the Industrial class.

20. The base fuel and fuel-related costs as approved in Docket No. E-7, Sub 1026 of 2.3182¢/kWh will be adjusted by amounts equal to (0.2298)¢/kWh, (0.1604)¢/kWh, and

(0.1029)¢/kWh for the Residential, General Service/Lighting and Industrial customer classes, respectively. The resulting approved fuel and fuel-related costs will be further adjusted by EMF and EMF interest increments/(decrements) totaling 0.0298¢/kWh, 0.0173¢/kWh, and (0.0034)¢/kWh for the Residential, General Service/Lighting and Industrial customer classes, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending December 31st as the test period for DEC. The Company's filing in this proceeding was based on the 12 months ended December 31, 2014.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the application, the direct and supplemental testimony of Company witness Smith, and the entire record in this proceeding. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the testimony of Company witnesses Gillespie and Miller and the affidavit of Public Staff witness Lucas.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC) Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Gillespie testified that the Company's seven nuclear units operated at a system average capacity factor of 92.14% during the test period. This capacity factor, as well as the Company's 2-year average nuclear capacity factor of 93.88%, exceeded the five-year industry weighted average nuclear capacity factor of 87.56% for the period 2009-2013 for comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Witness Gillespie testified that for the fifteenth consecutive year, DEC's seven nuclear units achieved a system average capacity factor exceeding 90%, ending the year, which included five refueling outages, with an average of 92.14%. Oconee set a site capacity factor record for the year with 94.73%, beating the 2013 record of 94.55%. For continuous operating days leading into

2014 refueling activities, Catawba Unit 1 achieved a run of 493 days, McGuire Unit 2 achieved a run of 474 days, and Oconee Unit 3 achieved a run of 385 days.

Company witness Gillespie testified that there were five refueling and maintenance outages during the test period beginning with the spring 2014 refueling and maintenance outage on McGuire Unit 2. Along with refueling, major work efforts included a replacement for the third of eight reactor coolant pump motors with a more robust stator design. Improved glow coil design hydrogen igniters were also replaced for improved reliability and engineering changes for component cooling thermal barrier flow were installed, cyber security changes were implemented, and the final connection of the reactor coolant cross-over skid was completed. A required increase of two and a half days over the outage allocation was required as a result of emergent work to address a boron injection line repair. In total, DEC successfully completed 13,123 work order tasks within this outage.

Company witness Gillespie also testified that in the spring, Oconee Unit 3 completed a refueling and maintenance outage. Major work along with refueling included a 10-year reactor vessel in-service inspection, cleaning of the air and water sides of reactor building cooling unit coils, steam generator eddy current testing, and installation of a redundant bus line differential relaying for the CT-3 transformer. Work was completed within a day of the scheduled allocation. In total, DEC successfully completed 11,455 work order tasks within this outage.

Company witness Gillespie testified that the final spring 2014 refueling and maintenance outage was for Catawba Unit 1. In addition to refueling efforts, major work involved installation of a measurement system in the feedwater lines that included spool assemblies with transducers welded in the feed flow stream in preparation for the scheduled power uprate project. Containment integrated leak rate testing was performed, along with volumetric inspection of the reactor vessel internals. In addition, the B service water system strainer, main generator high voltage bushings, and fire detection panels were replaced. Flow accelerated corrosion was also addressed during the outage by replacing the main feedwater and steam drain piping and lines. The outage was extended ten days over the time allocated for the outage to address a bearing issue on the A emergency diesel generator. Extent of condition efforts were completed and resulted in the required emergent replacement of eight main bearings for the A and B emergency diesel generators. In total, DEC successfully completed 14,410 work order tasks within this outage.

Company witness Gillespie further testified that McGuire Unit 1 was the first of the Company’s fall refueling and maintenance outages. In addition to refueling, major work efforts included significant inspection and maintenance efforts on various pumps, electrical, and valve components along with pump seal and rotating assembly replacements, and several in-service inspections. Other efforts included replacing the 1A reactor cooling pump motor with a more robust stator design, source, and intermediate range instrumentation, and replacing the 1B chemical and volume control pump rotating assembly. Additionally, the outage involved significant major project work with the replacement of the main generator stator and exciter, upgrading the main power relaying, installation of a cross-over manway to allow for cleaning of the main condenser circulating water system supply header, and completion of both mechanical and electrical connections associated with Fukushima-related modifications. Also notable was completion of the measurement uncertainty recapture power uprate on Unit 1, which allows for more accurate flow. This outage required a 22-day extension, most notably due to manufacturing defects associated with the generator stator, thermal fatigue requiring weld repairs, and excessive primary check valve leakage identified during startup testing. In total, DEC completed 18,187 work order tasks during this refueling outage.

Company witness Gillespie testified that Oconee Unit 1 was the final unit to be taken offline for a refueling and maintenance outage in 2014. In addition to refueling, major work activities included mechanical seal replacement on the high pressure injection pump, replacement of the 1B condensate pump motor, and replacement of 1D1 and 1E2 heater drain pumps. In addition, several inspections were performed on piping for thickness and weld quality, on the high pressure injection nozzles, on the primary and secondary valves, and on the feedwater heaters and pressurizer components. The outage was completed two days under the outage allocation time and, in total, DEC successfully completed 12,171 work order tasks within this outage.

Company witness Miller testified concerning the performance of DEC's fossil/hydro assets. He stated that the primary objective of the Company's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEC's customers, and that it achieves this objective by focusing on a number of key areas. Witness Miller further stated that environmental compliance is a "first principle" and that DEC achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers.

Company witness Miller testified that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate operational performance, depending on the generator type: (1) equivalent availability factor (EAF), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (*i.e.*, forced) outage time); (2) net capacity factor (NCF), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF is affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate (EFOR), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated [1] hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and (4) starting reliability (SR), which represents the percentage of successful starts.

Company witness Miller presented the following chart, which shows operation results, as well as results from the most recently published NERC Generating Availability Brochure for the period 2009 through 2013, and is categorized by generator type:

[1] Derated hours are hours the unit operation was less than full capacity.

Generator Type	Measure	Review Period	2009-2013	Nbr of Units
		DEC Operational Results	NERC Average	
Coal-fired Test Period	EAF	79.6%	81.6%	820
	NCF	50.4%	63.1%	
	EFOR	14.7%	7.9%	
Coal-fired Summer Peak	EAF	86.1%	n/a	n/a
Total CC Average	EAF	90.1%	85.3%	323
	NCF	67.5%	47.7%	
	EFOR	0.7%	6.3%	
Total CT	EAF	95.7%	87.9%	934
Average	SR	99.4%	97.5%	
Hydro	EAF	94.3%	83.7%	1077

Company witness Miller testified that the NERC data reported for the coal-fired units represents an average of comparable units based on capacity rating along with the EAF for the peak summer period of June through August. He also testified that although coal-fired metrics for the test period were impacted by an extended outage at Marshall Unit 4 in 2014, the Company's coal fleet has a long history of better than industry average availability. Excluding Marshall Unit 4, operational results for the remainder of the coal fleet were significantly better, with an EAF of 85.1% and EFOR of 6.0%.

Concerning the Marshall Unit 4 outage, witness Miller testified that on April 21, 2014, Marshall Unit 4 was forced off line with a generator ground. Testing indicated significant damage to the generator stator core. Company personnel, supported by the original equipment manufacturer (OEM), evaluated repair versus replacement options. The recommended option for long-term generator reliability included full stator core replacement and a stator and rotor rewind.

All stator work was completed on site in parallel with the rotor rewinding at an off-site facility. The full stator core replacement required extensive rigging and lifting from a horizontal orientation to a vertical orientation to facilitate the installation. In addition, the stator was moved outside the powerhouse to a temporary 5000 square-foot structure constructed to house and install the stator core.

The duration for generator activities was projected to be six to seven months and included estimates for procurement of materials, fabrication, construction of the on-site temporary facility for the core replacement, lifting and rigging efforts, installation of the new core, stator rewind, generator reassembly, and testing. The 11-week turbine boiler maintenance outage, originally planned for spring 2015, was moved into the generator outage window. Outage activities included turbine inspection, pulverizer rebuilds, boiler feed pump turbine rotor replacement, and replacement of the front and rear boiler waterwalls.

Witness Miller testified that the Company, along with the OEM and industry experts, performed an extensive evaluation of the cause of the generator failure. A 1998 maintenance activity (1998 Over Flux Event), which caused the voltage regulator to produce excessive field current as well as a stator overvoltage condition for approximately five minutes, has been identified as the likely initiating cause that created a long-term failure mode through chronic localized heating between stator core laminations. Witness Miller testified that factors that could have contributed to the generator remaining operational for 16 years after the initiating 1998 Over Flux Event were also reviewed as part of the root cause investigation. The Marshall Unit 4 generator stator was rewound in 2006, and stator insulation was upgraded from a Class B (90 degree C) to a Class F (105 degree C) rated insulation. Witness Miller testified that it is probable that the 2006 generator winding insulation upgrade contributed to the reliable operation of the generator from the 1998 Over Flux Event to failure in 2014. The spread rate and intensity of the hot spot was a gradual process that deteriorated the core over time. The 2006 generator rewind with upgraded insulation likely delayed the eventual failure of the generator.

Company witness Miller also testified that the Company performed the industry standard core condition testing including the Electromagnetic Core Imperfection Detection (EL-CID) test with no signs of core anomalies. EL-CID testing is an industry standard core fitness testing, and DEC performed the test in 2006 at the time of the rewinds without negative indication on the core iron.

Concerning significant planned outages occurring at the Company's fossil and hydroelectric facilities during the test period, Company witness Miller testified that in general, planned maintenance outages for all fossil and larger hydroelectric units are scheduled for the spring and fall to maximize the units' availability during periods of peak demand. During the test period, most of these units had at least one small planned outage to inspect and maintain plant equipment.

Public Staff witness Lucas testified that the Public Staff did not recommend any adjustment related to the portion of the Marshall 4 outage occurring during the current test year; however, since the total outage time extended beyond the current test year, the Public Staff reserved the right to continue its investigation and make recommendations on this outage, as appropriate, in future proceedings.

Based upon the evidence in the record, the Commission concludes that DEC managed its baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in December 2014, and, in combination with the Company's prior fuel procurement practices filed with the Commission in July 2004, were in effect throughout the 12 months ending December 31, 2014. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses Smith, Daji, Miller, and Culp.

Company witness Smith testified that DEC's fuel procurement strategies that mitigate volatility in supply costs are a key factor in DEC's ability to maintain lower fuel and fuel-related rates. Other key factors include DEC's diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; the combination of DEP's and DEC's respective skills in procuring, transporting, managing and blending fuels and procuring reagents; the increased and broader purchasing ability of the combined Company; and the joint dispatch of DEP's and DEC's generation resources.

Company witness Daji described DEC's fossil fuel procurement practices, set forth in Daji Exhibit 1. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, and conducting short-term and spot purchases to supplement term supply.

According to witness Daji, the Company's average delivered coal cost per ton decreased 8.6%, from $100.30 per ton in the prior test period to $91.72 per ton in the test period. The Company's transportation costs increased approximately 1.2%, from $31.72 per ton in the prior test period to $32.11 per ton in the test period. Witness Daji stated that coal markets continue to be in a state of flux due to a number of factors, including (1) recent U.S. Environmental Protection Agency regulations for power plants that result in utilities retiring or modifying plants, which lowers total domestic steam coal demand, and can result in some plants shifting coal sources to different basins; (2) softening demand in global markets for both steam and metallurgical coal; (3) low natural gas prices and increased volatility due to continued increase in gas supply combined with installation of new combined cycle (CC) generation by utilities, especially in the Southeast, which also lowers overall coal demand; and (4) increasingly stringent safety regulations for mining operations, which result in higher costs and lower productivity.

Witness Daji stated that due to increasing competitiveness between natural gas and coal for low cost electricity, DEC's coal generation will fluctuate with prevailing market conditions. She further stated that as natural gas prices have declined in response to strong supply, and as coal generation has decreased due to planned outages of key coal-fired generating units, the actual coal burn of 12.0 million tons for the test year represents an 8.6% decline compared to DEC's average annual coal burn over the prior five-year period of over 13 million tons. DEC's current coal burn projection for the billing period is 12.1 million tons, which is about the same as the 12.0 million tons DEC consumed during the test period. DEC's billing period projections for coal generation may be impacted by changes in natural gas prices, volatile power prices, and demand. Coal inventory levels were above target at the end of 2014, and future actual inventory levels may be above target levels at the end of 2015 as well. She also testified that combining coal and transportation costs, DEC projects average delivered coal costs of approximately $80.40 per ton for the billing period. This represents a 12.3% decrease compared to the 2014 actual cost.

According to witness Daji, DEC continues to maintain a comprehensive coal procurement strategy that has proven successful over many years in limiting average annual coal price increases and maintaining average coal costs at or well below those seen in the marketplace. Aspects of this procurement strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, and pursuing contract extension options that provide flexibility to extend terms within a particular price band. Witness Daji further testified that the Company expects to address any spot and long-term coal requirements throughout this year through competitively bid purchases, taking into account projected coal burns as well as coal inventory levels.

Witness Daji further testified that the Company's natural gas consumption is expected to continue to increase. The Company consumed approximately 56 billion cubic feet (Bcf) of natural gas in the test period, compared to approximately 63 Bcf in 2013, the prior test period. The primary driver of the lower natural gas burns during the test period was higher natural gas prices in 2014 compared to 2013. For the billing period, DEC's current forecasted natural gas consumption is approximately 64 Bcf.

Witness Daji also testified that the development of shale gas has created a fundamental shift in the nation's natural gas market. In recent years, improvements in production technologies have allowed greater access to the natural gas trapped in shale formations, resulting in increased reserves that can produce natural gas supply more quickly and economically. Given continued production increases, natural gas prices continue to remain at lower levels. The Company's average price of gas purchased for the test period was $5.50 per million British Thermal Units (MMBtu), compared to $4.35 per MMBtu during the prior test period.

G.S. 62-133.2(a1)(3) permits DEC to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Miller testified that the selective catalytic reduction (SCR) technology that DEC currently operates uses ammonia or, in the case of Marshall Unit 3, urea (which is converted to ammonia), for nitrogen oxide (NO_x) removal. The selective non-catalytic reduction technology employed by DEC injects urea into the boiler for NO_x removal, and the scrubber technology uses crushed limestone for sulfur dioxide (SO_2) removal. Dibasic acid can also be used with the scrubber technology for additional SO_2 removal. SCR equipment is also an integral part of the design of the Buck and Dan River CC Stations, in which aqueous ammonia (19% solution of NH_3) is introduced for NO_x removal.

Company witness Miller further testified that overall, the type and quantity of chemicals used to reduce emissions at the Company's plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and the level of emissions reduction required. He stated that the Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and changes in coal burn due to competing fuels and utilization of non-traditional coals. He also stated that the goal is to comply effectively with emissions regulations and provide the most efficient total-cost solution for operation of the unit.

Company witness Culp testified as to DEC's nuclear fuel procurement practices, which include computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of spot and long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Culp explained that for uranium concentrates as well as conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that throughout the industry, the typical initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, DEC relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis, using multi-year contracts.

G.S. 62-133.2(a1)(4), (5), (6), and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Daji testified that in assessing power purchases and off-system sales opportunities, DEP and DEC consider the latest forecasted fuel prices, outages at the generating units based on planned maintenance and refueling schedules, forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions, in order to determine the most economic and reliable means of serving their customers.

In its post-hearing brief, NCSEA states that it does not challenge any costs for which DEC seeks recovery in its fuel and fuel-related rider application as unreasonable or imprudent. However, NCSEA requests that the Commission encourage DEC to continue its prudent natural gas hedging practices and to continue to explore diversifying its supply portfolio to include more clean energy solutions that do not consume fuel. Thus, the Commission notes that NCSEA does not oppose recovery of DEC's proposed fuel and fuel-related costs in this proceeding. In addition, the Commission notes that in future fuel and fuel-related charge adjustment proceedings NCSEA is free to challenge DEC's fuel procurement and power purchasing practices.

In summary, no party presented or elicited testimony contesting the Company's fuel and reagent procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the absence of any evidence to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the testimony of Company witnesses Daji and Smith.

Company witness Daji testified about the JDA, which is an agreement between DEP and DEC whereby DEC acts as the Joint Dispatcher for DEC's and DEP's power supply resources. She stated that the JDA has allowed DEP's and DEC's generation resources to be dispatched as a single system to meet the utilities' retail and firm wholesale customers' requirements at the lowest possible cost. According to witness Daji, the joint dispatch process allows DEP and DEC to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis.

Witness Daji testified that the JDA provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between DEP and DEC (the Companies). The joint dispatch savings automatically flow through to the Companies' retail customers through the fuel clause. For native load wholesale customers, the joint dispatch savings are passed through as permitted by the applicable wholesale contracts. Under the joint dispatch process, the energy costs attributable to each utility's native load are the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by DEC as the Joint Dispatcher, which are treated as purchases and sales between the Companies. As a result, the energy cost totals ultimately incurred by DEP and DEC to serve their respective native loads will be equal to the stand-alone costs they would have incurred but for the joint dispatch arrangement, less each utility's share of the joint dispatch savings.

According to witness Daji, through January 2015, the combined merger savings from the JDA and the Companies' fuel procurement activities are $445 million. DEC's and DEP's customers are allocated their share of the combined savings based upon the resource ratios of the combined Companies. This resource ratio is 61.3% for DEC and 38.7% for DEP through January 2015.

Company witness Smith testified that merger fuel-related savings automatically flow through to DEC's retail customers through the fuel and fuel-related cost component of customers' rates. She explained that actual merger fuel-related savings during the test period are included in the EMF portion of the proposed fuel and fuel-related cost factors. In addition, the projected merger fuel-related savings related to the procurement of coal and reagents, lower transportation costs, lower gas capacity costs, and coal blending are reflected in the cost of fossil fuel in the projected component of the fuel and fuel-related cost factors. Projected joint dispatch savings, which result from using DEC's and DEP's combined systems' lowest available generation to meet total customer demand, are also reflected in the cost of fossil fuel as well as the projected cost purchases and sales that include the purchases and sales between DEC and DEP.

Based on the evidence presented by DEC, and noting the absence of evidence presented to the contrary by any other party, the Commission finds and concludes that the Company's merger-related fuel savings for the test period are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Smith.

According to the exhibits sponsored by Company witness Smith, the test period per book system sales were 84,869,637 MWh, and test period per book system generation and purchased power amounted to 92,394,459 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Smith Exhibit 6):

Net Generation Type	MWh
Coal	31,596,676
Natural Gas, Oil and Biomass	7,878,015
Nuclear	42,380,803
Hydro – Conventional	1,916,588
Hydro Pumped Storage	(732,113)
Solar DG	13,175
Purchased Power – subject to economic dispatch or curtailment	7,200,567
Other Purchased Power	1,393,722
Catawba Interchange	747,026
Total Net Generation	92,394,459

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 4.

No party took issue with the portions of witness Smith's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence to the contrary, the Commission concludes that the per books levels of test period system sales of 84,869,637 MWh and system generation and purchased power of 92,394,459 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Gillespie and the affidavit of Public Staff witness Lucas.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and any unusual events. The Company proposed using a 93.56% capacity factor in this proceeding based on the operational history of the Company's nuclear units, and the number of planned outage days scheduled during the 2015-2016 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 87.56% for the period 2009-2013 for comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report. Public Staff witness Lucas did not dispute the Company's proposed use of a 93.56% capacity factor.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEC system, and the fact that no party disputed the Company's proposed capacity factor, the Commission concludes that the 93.56% nuclear capacity factor, and its associated generation of 58,843,888 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Smith.

On her Exhibit 4, Company witness Smith set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 57,252,194 MWh, comprised of Residential class sales of 21,274,670 MWh, General Service/Lighting class sales of 23,163,092 MWh, and Industrial class sales of 12,814,433 MWh.

Witness Smith used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on Smith Exhibit 2, Schedule 1, is 86,360,640 MWh. The projected level of generation and purchased power used was 93,046,731 MWh (calculated using the 93.56% capacity factor found reasonable and appropriate above), and was broken down by witness Smith as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	32,149,466
Gas Combustion Turbine (CT) and Combined Cycle (CC)	8,963,548
Nuclear	44,609,541
Hydro	1,694,430
Net Pumped Storage Hydro	(721,819)
Solar Distributed Generation (DG)	13,544
Purchased Power	6,338,021
Total	93,046,731

As part of her Workpaper 7, Company witness Smith also presented an estimate of the projected billing period North Carolina retail Residential, General Service/Lighting, and Industrial MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,436,638
General Service/Lighting	23,280,005
Industrial	12,657,825
Total	57,374,468

These class totals were used in Smith Exhibit 2, Schedule 1, in calculating the total fuel and fuel-related cost factors by customer class.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and the absence of evidence presented to the contrary, the Commission concludes that the projected North Carolina retail levels of sales set forth in the Company's exhibits (normalized for customer growth and weather), as well as the projected levels of generation and purchased power, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses Smith and Daji and the affidavit of Public Staff witness Lucas.

Company witness Smith recommended fuel and fuel-related prices and expenses, for purposes of determining projected system fuel expense, as follows:

A. The coal fuel price is $32.413/MWh.
B. The gas CT and CC fuel price is $33.16/MWh.
C. The appropriate system expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $44,250,039.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.369/MWh.
E. The total system purchased power cost (including the impact of JDA Savings Shared) is $208,963,940.
F. System fuel expense recovered through intersystem sales is $24,886,424.
G. The system avoided fuel benefit related to solar distributed generation is $194,114.

These amounts are set forth on or derived from Smith Exhibit 2, Schedule 1. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company and the Public Staff.

In his affidavit, Public Staff witness Lucas stated that based on his review it appears that the projected fuel and reagent costs set forth in DEC's testimony, and the prospective components of the total fuel factor, have been calculated in accordance with the requirements of G.S. 62-133.2.

No other party presented evidence on the level of DEC's fuel and fuel-related prices and expenses.

Based upon the evidence in the record as to the appropriate fuel and fuel-related prices and expenses, the Commission concludes that the fuel and fuel-related prices recommended by Company witness Smith and accepted by the Public Staff for purposes of determining the projected system fuel expense are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Smith and the affidavit of Public Staff witness Lucas.

Consistent with G.S. 62-133.2(a2), witness Smith testified that the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs does not exceed two percent of DEC's total North Carolina jurisdictional gross revenues for 2014.

According to Smith Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,230,584,963. Public Staff witness Lucas did not take issue with her calculation.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any evidence to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $1,230,584,963 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-19

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Smith and the affidavits of Public Staff witnesses Lucas and Peedin.

Company witness Smith presented DEC's fuel and fuel-related expense over-collection and prospective fuel and fuel-related cost factors. Company witness Smith's testimony sets forth the projected fuel and fuel-related costs, the amount of over/(under) collection for purposes of the EMF, the method for allocating the increase in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and the EMFs along with exhibits and workpapers reflecting the stipulated adjustments. Public Staff witness Lucas recommended the approval of the prospective and EMF components and total fuel factors (excluding regulatory fee) set forth in Company witness Smith's testimony.

Public Staff witness Peedin testified that the EMF riders proposed by DEC are based on DEC's calculated and reported North Carolina retail fuel and fuel-related cost under-recoveries of $6,335,555 and $4,010,658 for the Residential and General Service/Lighting classes, respectively, and an over-recovery of $365,295 for the Industrial class. Public Staff witness Peedin also testified that interest on the over-recovered fuel and fuel-related amount from the Industrial class amounted to $60,883. She recommended that DEC's EMF riders for each customer class be based on these net fuel and fuel-related cost under-recovery and over-recovery amounts, and on the Company's proposed normalized North Carolina retail sales of 21,274,670 MWh for the residential class, 23,163,092 MWh for the general service/lighting class, and 12,814,433 MWh for the industrial class, as proposed by the Company. She stated that these amounts produce EMF increment and decrement riders for each North Carolina retail customer class as follows, excluding the regulatory fee (decrements shown in parentheses):

Residential	0.0298 cents per kWh
General Service/Lighting	0.0173 cents per kWh
Industrial	(0.0029) cents per kWh

She also recommended an EMF interest decrement rider for the industrial class of (0.0005) cents per kWh, excluding the regulatory fee, resulting from the over-recovered fuel amount from the industrial class.

As a result of witness Peedin's recommendation, Public Staff witness Lucas recommended the following EMF and EMF interest increment/(decrement) billing factors:

N.C. Retail Customer Class	EMF Increment/ (Decrement) (cents/kWh)	EMF Interest Increment/ (Decrement) (cents/kWh)
Residential	0.0298	
General Service/Lighting	0.0173	
Industrial	(0.0029)	(0.0005)

These factors are also set forth on Smith Exhibit 1.

The Commission concludes that the EMF and EMF interest increment/(decrement) billing factors set forth in the affidavits of Public Staff witnesses Lucas and Peedin are reasonable and appropriate for use in this proceeding.

Company witness Smith calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. She stated that the decrease in fuel costs from the amounts approved in Docket No. E-7, Sub 1051, should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEC fuel cases approved by this Commission. No party opposed the use of this allocation method. Public Staff witness Lucas recommended the approval of the prospective and total fuel and fuel-related cost factors, excluding regulatory fee, set forth in Company witness Smith's testimony.

Based upon the testimony and exhibits in the record, the Commission concludes that DEC's projected fuel and fuel-related cost of $1,230,584,963 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that (1) DEC's EMFs proposed in this proceeding, excluding the regulatory fee, (2) DEC's prospective fuel and fuel-related cost factors proposed in this proceeding for each of DEC's rate classes, and (3) DEC's EMF interest decrements proposed in this proceeding, excluding the regulatory fee, are all appropriate. Additionally, the Commission concludes that DEC's decrease in fuel and fuel-related costs from the amounts approved in Docket No. E-7, Sub 1051 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEC's past fuel cases.

The following tables summarize the impact of the rates approved in this case and the rates approved in Docket No. E-7 Sub 1051, excluding regulatory fee, as compared to the composite base fuel and fuel-related cost factor of 2.3182 cents/kwh approved by the Commission in the Company's most recent general rate case, Docket No. E-7, Sub 1026:

Approved in Docket No. E-7, Sub 1051 (excluding regulatory fee):

Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Prospective Component	(0.2037)	(0.0748)	(0.0441)
EMF Component	0.0368	(0.0436)	(0.0427)
Total Fuel Factor	(0.1669)	(0.1184)	(0.0868)

Proposed in this Docket No. E-7, Sub 1072 (excluding regulatory fee):

Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Prospective Component	(0.2298)	(0.1604)	(0.1029)
EMF Component	0.0298	0.0173	(0.0034)
Total Fuel Factor	(0.2000)	(0.1431)	(0.1063)

Summary of Differences Sub 1072 – Sub 1051 (excluding regulatory fee):

Description	Residential cents/kWh	General Service Lighting cents/kWh	Industrial cents/kWh
Prospective Component	(0.0261)	(0.0856)	(0.0588)
EMF Component	(0.0070)	0.0609	0.0393
Total Fuel Factor	(0.0331)	(0.0247)	(0.0195)

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence for this finding of fact is contained in the testimony of Company witness Smith and in the affidavits of Public Staff witnesses Peedin and Lucas and is discussed in more detail in Evidence and Conclusions for Finding of Fact No. 5.

The Commission has carefully reviewed the evidence and record in this proceeding. The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF, are not opposed by any party. Accordingly, the overall fuel and fuel-related cost calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 2.1182¢/kWh for the Residential class, 2.1751¢/kWh for the General Service/Lighting class, and

2.2119¢/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 2.0884¢/kWh, 2.1578¢/kWh, and 2.2153¢/kWh, EMF increments (decrements) of 0.0298¢, 0.0173¢, and (0.0029)¢/kWh, and EMF interest decrements of (0.0000)¢/kWh, (0.0000)¢/kWh, and (0.0005)¢/kWh, for the Residential, General Service/Lighting, and Industrial classes, all respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after September 1, 2015, DEC shall adjust the base fuel and fuel-related costs in its North Carolina retail rates of 2.3182¢/kWh, as approved in Docket No. E-7, Sub 1026, by amounts equal to (0.2298)¢/kWh, (0.1604)¢/kWh and (0.1029)¢/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively, and further, that DEC shall adjust the resulting approved fuel and fuel-related costs by EMF increments/(decrements) of 0.0298¢/kWh for the Residential class, 0.0173¢/kWh for the General Service/Lighting class, and (0.0029)¢/kWh for the Industrial class (excluding the regulatory fee). DEC shall further adjust the fuel and fuel-related costs for the Industrial class by an EMF interest decrement of (0.0005)¢/kWh. The EMF increments, EMF decrement and EMF interest decrement are to remain in effect for service rendered through August 31, 2016.

2. That DEC shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments no later than 10 days from the date of this Order.

3. That DEC shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket No. E-7, Sub 1074, and the Company shall file such notice for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the _24th_ day of _July_, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-2, SUB 931

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	)	ORDER APPROVING REVISED COST RECOVERY AND INCENTIVE MECHANISM AND GRANTING WAIVERS

BY THE COMMISSION: On June 15, 2009, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required Modifications, which included Commission approval of the Cost Recovery and Incentive Mechanism for DSM/EE Programs (Mechanism) proposed by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (now Duke Energy Progress, Inc. or DEP), and agreed upon by the Public Staff – North Carolina Utilities Commission (Public Staff) and other parties.[1] Such Order provided that there would be a formal review of the Mechanism not later than June 1, 2012.

On November 14, 2011, in Docket No. E-2, Sub 1002, in the matter of the application by DEP for approval of demand-side management (DSM) and energy efficiency (EE) cost recovery rider pursuant to G.S. 62-133.9 and Commission Rule R8-69, the Commission issued an Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice (Sub 1002 Order). In that Order, among other things, the Commission directed in Ordering Paragraph No. 9 that the Public Staff shall initiate a formal review of DEP's Mechanism not later than June 1, 2012, unless requested to do so earlier by DEP or another interested party. The Sub 1002 Order stated that the Public Staff's review should

> specifically address whether the incentives in the Commission-approved Mechanism are producing significant DSM and EE results; whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate; whether overall portfolio performance targets should be adopted; and any other relevant issues that may be identified during the review process.

On April 10, 2012, in Docket No. E-2, Sub 931, the Public Staff filed a motion to extend the time to initiate the formal review to no later than June 1, 2014, unless requested to do so earlier by DEP or another interested party. In support of its motion, the Public Staff stated that the review of the cost recovery mechanisms for Duke Energy Carolinas, LLC (DEC) and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP) in Docket Nos. E-7, Sub 831 and E-22, Sub 473, respectively, were scheduled to occur in 2014. The Public Staff contended that postponing the review of PEC's Mechanism until 2014, when the DEC and DNCP cost recovery and incentive mechanisms were scheduled to be reviewed, would provide the

[1] On November 25, 2009, the Commission issued a further Order that amended its June 15, 2009 Order with respect to issues that are not part of the present review.

Commission and the parties to the proceeding with a better context in which to focus on the issues identified by the Commission for the review process, as well as with more comprehensive data with which to address those issues. On May 15, 2012, the Commission issued an Order granting the requested extension of time.

On June 10, 2014, DEP filed a petition requesting a review of the DEP Mechanism. In its petition, DEP submitted that its Mechanism is working well, producing meaningful DSM and EE results, and, consequently, needs only minor modifications. DEP stated that on April 9, 2014, the Public Staff and DEP met to initiate the Mechanism review, and held a follow-up meeting on June 3, 2014. DEP stated that the Public Staff and DEP agreed that the Mechanism has generally worked well with respect to functionality and transparency, and that any differences of opinion between the Public Staff and DEP have been resolved without significant controversy. As a result, neither DEP nor the Public Staff intended to propose any major changes during the review. In addition, with regard to the specific items identified in the Sub 1002 Order, DEP contended that the Mechanism incentives are producing significant and meaningful DSM and EE results, that customer rate impacts from the DSM/EE rider are reasonable and appropriate, and that there is no indication that overall portfolio performance targets should be adopted. Therefore, DEP did not believe that any changes with regard to these items are necessary.

In addition, DEP set forth in its petition a list of several proposed modifications to the Mechanism, which it described as minor modifications intended to streamline administration of the Mechanism and rider filings and to incorporate best practices that the Public Staff and DEP have identified and implemented since approval of the Mechanism. DEP noted that some of these include aspects of DEC's process that have been approved by the Commission. Further, DEP set forth in its petition a list of several potential modifications to the Mechanism that it was considering and would like to discuss with interested parties during the review. DEP also stated that pursuant to the provisions of the Sub 1002 Order, it was not proposing to review or modify DEP's portfolio of DSM and EE programs.

Finally, DEP provided a proposed procedural schedule for a meeting of interested parties, and the filing of comments and reply comments. DEP stated that it believes the Commission could make its decision in this matter based on DEP's filings and the parties' comments, without the need for an evidentiary hearing.

On June 12, 2014, the Commission issued an Order Establishing Procedural Schedule and Requesting Comments, which adopted a schedule for a meeting of DEP, the Public Staff, and all interested parties to discuss DEP's proposed changes to its Mechanism and other changes that the parties suggest. In addition, DEP, the Public Staff, and all interested parties were given the opportunity to file comments and reply comments on DEP's proposed changes to its Mechanism and other changes that the parties suggested.

On June 19, 2014, DEP filed a Notice of Stakeholder Meeting, which indicated that it had consulted with the parties and scheduled a stakeholder meeting to discuss proposed modifications to the Mechanism for June 26, 2014, at its Raleigh office located at 410 South Wilmington Street.

On July 8, 2014, attorney Mary Kathryn King, of Spilman Thomas & Battle, PLLC, filed notice of appearance as counsel of record for Wal-Mart Stores East, LP, and Sam's East, Inc. (collectively, Walmart).

On July 17, 2014, Environmental Defense Fund filed a Motion to Withdraw Intervention, which was granted by Commission Order issued on July 23, 2014. On July 21, 2014, Molly L. McIntosh, attorney for DEP, filed notice of change of firm and contact information.

The Public Staff filed motions to extend the comment deadlines for all parties on July 30, 2014 and August 29, 2014, which were granted by Commission Orders issued on August 1, 2014 and September 3, 2014.

On August 13, 2014, attorney Stephanie U. Roberts, of Spilman Thomas & Battle, PLLC filed notice of appearance and substitution of counsel on behalf of Walmart.

Initial comments were filed by DEP and jointly by the Natural Resources Defense Council (NRDC) and the Southern Alliance for Clean Energy (SACE) on September 11, 2014, and by the Public Staff on September 12, 2014.[1] In its initial comments, DEP reasserted the general statements in its petition. In addition, DEP stated that it had hosted a stakeholder meeting on June 26, 2014, and that it had served its proposed redlined version of the Mechanism (which was filed with its initial comments) on all parties on July 17, 2014. Further, DEP stated that the Public Staff was the only party that had engaged DEP in substantive discussions regarding the proposed modifications and changes to the Mechanism, and that DEP and the Public Staff had reached agreement in principle as to almost all proposed modifications to the Mechanism.

In their initial comments, NRDC and SACE advocated for a predictable, performance-based incentive in which the Company earns a greater incentive if its customers save more energy. In response to the Commission's first question included in the Sub 1002 Order, NRDC and SACE stated that the incentives in the current DEP Mechanism have produced significant DSM and EE results to date, although not on par with leading utilities, but noted that the Company forecasts a decline in energy savings.

In response to the Commission's question whether overall portfolio performance targets should be adopted, NRDC and SACE stated that the answer was "yes." They argued that DEP should achieve a specific energy efficiency threshold, based on savings as a percentage of the prior year's retail sales, before it receives a Program Performance Incentive (PPI), and that the PPI percentages should increase as the Company achieves specific energy savings targets above that threshold. In addition, they suggested that the Commission may wish to tie the incentive to additional metrics based on specific policy goals, such as serving low-income customers or other hard-to-reach customer sectors. NRDC and SACE also discussed the role of energy efficiency in North Carolina's implementation of the Environmental Protection Agency's proposed Clean Power Plan and the importance of the Commission encouraging DEP to invest in energy efficiency to reduce the cost of compliance. Finally, NRDC and SACE indicated that they supported DEP's proposals to request a waiver of Commission Rule R8-69(a)(4) and (5) so that the test period and

[1] On September 12, 2014, the Commission issued an Order approving the Public Staff's verbal motion to extend the filing date for its initial comments from September 11, 2014 to September 12, 2014.

rate period of the DSM/EE rider align with the calendar year; to change the filing date for the annual DSM/EE rider application to a single filing in July of each year; to incorporate the DEC Flexibility Guidelines from Docket No. E-7, Sub 831, which were incorporated into Docket No. E-7, Sub 1032;[1] and to adopt the EM&V Agreement from Docket No. E-7, Sub 979[2], which was also incorporated into Docket No. E-7, Sub 1032.

In its comments filed on September 12, 2014, the Public Staff first indicated, in response to the Commission's question, that it could not definitively determine whether the incentives in the Mechanism are producing the optimal level of DSM and EE savings. However, the Public Staff suggested that a "market potential study" could be a useful tool to assess how actual DSM/EE savings compare to achievable savings.

The Public Staff responded to the Commission's second question by noting that rate impacts on customers are reasonable because DEP's programs generally have cost effectiveness test results of greater than 1.00 under the Utility Cost Test and the Total Resource Cost test.

With regard to the Commission question on performance targets, the Public Staff recommended that the DEP Mechanism be revised to provide for a $400,000 annual bonus for years in which the Company achieves EE savings equal to or greater than 1% of weather-normalized retail sales. That would match the performance target recently adopted for DEC. The Public Staff stated that future reviews could assess the efficacy of this performance target and determine if a different performance target would be more effective.

The Public Staff's September 12, 2014 comments also contained a summary of recommended changes to the Mechanism, and included a revised Mechanism along with Mechanism Attachments A, B, and C. These recommendations include changes that were initially proposed by DEP, and that require waivers of certain parts of Commission Rule R8-69 with regard to increased flexibility for "Opt-Out" eligible customers (revised Mechanism Paragraph 36), aligning the test period and rate period with the calendar year (revised Mechanism Paragraph 37), and moving the filing date for the annual DSM/EE rider application (revised Mechanism Paragraph 39).

On September 25, 2014, DEP filed its Reply Comments and included a revised redlined version of the Mechanism, which contained the following three modifications from the version of the Mechanism filed by the Public Staff with its September 12, 2014 comments: (1) correction of Paragraphs 34 and 79 to conform to the Commission's November 25, 2009 Order Granting Motions for Reconsideration in Part in this docket and Docket No. E-2, Sub 926; and (2) a revision to Paragraph 78 to reflect DEP's position that calculation of the bonus incentive available to DEP if it achieves incremental energy savings of 1% of the prior year's system retail electricity sales in any year from 2015 through 2019 should be net of sales to customers who choose to opt out of participation in the DSM/EE rider.

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[1] Docket No. E-7, Sub 1032, pertained to the matter of application of DEC for approval of new cost recovery mechanism and portfolio of DSM and EE programs.

[2] For additional information concerning the EM&V Agreement, see the supplemental testimony of DEC witness Duff filed on September 26, 2011, in Docket No. E-7, Sub 979, in the matter of application of DEC for approval of DSM and EE cost recovery rider pursuant to G.S. 62-133.9 and Commission Rule R8-69.

On October 29, 2014, DEP filed notice with the Commission that DEP, NRDC, SACE, and the Public Staff had reached agreement regarding modifications to the Mechanism, and DEP filed the agreed-to Mechanism for approval. In its notice, DEP advised that DEP, NRDC, SACE, and the Public Staff have agreed that at such time as DEP, in an annual application for approval of a DSM/EE cost recovery rider, seeks the bonus incentive established in Paragraph 78 of the Mechanism, these parties reserve their rights to take differing positions on whether the calculation of the bonus incentive should include or be net of sales to customers who chose to opt out of participation in the DSM/EE rider.

No other parties filed any comments. On November 7, 2014, DEP, the Public Staff, NRDC, and SACE filed a Joint Proposed Order.

G.S. 62-133.9(d) authorizes the Commission to approve an annual rider to the rates of electric public utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new DSM and EE programs. The costs include, but are not limited to, all capital costs, including costs of capital and depreciation expense, administrative costs, implementation costs, incentive payments to participants, and operating costs. The Commission is also authorized to approve incentives for the utility for the adoption and implementation of new DSM and EE programs, including Net Lost Revenues (NLR) and appropriate rewards based on the sharing of savings achieved by the programs. The annual DSM/EE rider is composed of two parts: (1) the utility's forecasted costs, along with incentives, during the rate period, and (2) an experience modification factor to collect the difference between the utility's actual reasonable and prudent costs and incentives incurred during the test period and actual revenues realized during the test period.

The Commission has reviewed the filings of the parties to this proceeding, including the agreement among DEP, the Public Staff, NRDC, and SACE and the revised Mechanism, and is of the opinion that the revised Mechanism constitutes a reasonable method to provide for recovery of costs and appropriate utility incentives related to DEP’s DSM and EE activities. Therefore, the Commission concludes that the proposed revisions to the Mechanism agreed to by DEP, NRDC, SACE, and the Public Staff, attached hereto as Appendix A, are reasonable and appropriate, serve the public interest, and should be approved. Further, the Commission concludes that the incentives proposed in the Mechanism, including NLR and the PPI, and the bonus incentive, subject to the restrictions set forth in the Mechanism and continuing review for reasonableness, are reasonable and appropriate and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the following waivers of Commission Rules are granted: (a) a waiver of Rule R8-69(d)(3) to (i) allow the Company to implement and manage the opt-out elections of individual commercial customer accounts with annual energy usage of not less than 1,000,000 kilowatt-hours (kWh), and any industrial customer accounts, not to participate in either the Company's DSM programs or its EE programs, or both in combination, similar to the waiver set forth in the Commission's Order Granting Waiver, in Part, and Denying Waiver, in Part issued on April 6, 2010, in Docket No. E-7, Sub 938 for DEC; and (b) waivers of Rules R8-69(a)(4) and R8-69(a)(5) to change the test period and rate period for DEP’s DSM/EE rider to align with the calendar year, for the duration of the Mechanism, unless otherwise ordered by the Commission in the future.

2. That DEP's flexibility to make program modifications either with or without Commission approval shall be governed by the provisions of the approved revised Mechanism, including Attachment A thereto.

3. That the identification of net found revenues for purposes of determining DEP's recovery of DSM/EE NLR shall be governed by the provisions of the approved revised Mechanism, including Attachment C thereto.

4. That the Mechanism filed by DEP, and agreed to by the Public Staff, NRDC, and SACE, attached hereto as Appendix A, including Attachments A-C, is hereby approved.

5. That the attached Mechanism shall be effective for DSM and EE costs and utility incentives associated with time periods beginning on or after January 1, 2016.

6. That the Company and Public Staff shall study the issue of the appropriate avoided transmission and distribution (T&D) costs to be used in the Company's calculations of cost-effectiveness and, if any adjustment is determined to be appropriate, the proposed adjustment shall be filed in the Company's 2015 DSM/EE rider proceeding to be effective on a prospective basis for vintage (calendar) year 2016.

7. That the Public Staff shall initiate a formal review of the Company's Mechanism not later than February 1, 2019, unless requested to do so earlier by the Commission, the Company, or another interested party. The Public Staff's review should specifically address whether the incentives in the Commission-approved Mechanism are producing significant DSM and EE results; whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate; whether overall portfolio performance targets should be adopted; and any other relevant issues that may be identified during the review process.

ISSUED BY ORDER OF THE COMMISSION.
This the _20th_ day of January, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

COST RECOVERY AND INCENTIVE MECHANISM FOR DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS

(Docket No. E-2, Sub 931, as Modified by the Commission, to be Effective January 1, 2016)

The purpose of this Mechanism is (1) to allow Duke Energy Progress, Inc. (DEP or Company), to recover all reasonable and prudent costs incurred for adopting and implementing demand-side management (DSM) and energy efficiency (EE) Measures defined as new under G.S. 62-133.9, Commission Rules R8-68 and R8-69, the Commission's orders, and the additional principles set forth below; (2) to establish the terms, conditions, and methodology to be used for the recovery of Net Lost Revenues (NLR) and a Portfolio Performance Incentive (PPI) to reward DEP for adopting and implementing DSM and EE Measures and Programs, based on the sharing of dollar savings achieved by those Measures and Programs, if the Commission deems such recovery and reward appropriate; (3) to provide for an additional incentive to further encourage kilowatt-hour (kWh) savings achievements; and (4) to establish certain terms, requirements, and guidelines that will govern and/or guide (a) requests by DEP for Commission approval of DSM and EE Programs, (b) Program management and modifications, (c) Evaluation, Measurement, and Verification (EM&V) of Programs, (d) procedural matters and the general structure of the DSM/EE and DSM/EE EMF riders, (e) regulatory reporting requirements, and (f) DEP's Stakeholder Collaborative. The definitions set out in G.S. 62-133.8 and G.S. 62-133.9 and Commission Rules R8-68 and R8-69 apply to this Mechanism, except as may be otherwise explicitly provided for herein. For purposes of this Mechanism, the definitions listed below also apply.

Changes in the terms and conditions of this Mechanism shall be applied prospectively only, to Vintage Years following any Commission order amending these terms and conditions. With respect to the recovery of reasonable and prudent Program Costs and NLRs, except as may be explicitly provided for in the Mechanism, approved Programs and Measures shall continue to be subject to the terms and conditions that were in effect when they were approved. With respect to the recovery of PPIs, except as may be explicitly provided for in the Mechanism, approved Programs and Measures shall continue to be subject to the terms and conditions in effect in the Vintage Year that any applicable Measurement Unit was installed.

Definitions

1. *Common Costs* are administrative and general, or other, costs that are not attributable or directly assignable to specific DSM or EE Programs but are necessary to design, implement, and operate the Programs collectively.

2. *Incremental Program Costs* are utility-incurred costs directly attributable and expended solely for a specific DSM or EE Program, and include all appropriate capital costs (cost of capital, depreciation expenses, property

taxes, and other associated costs found reasonable by the Commission), implementation costs, incentive payments to Program participants, other operations and maintenance costs, EM&V costs, and administrative and general costs incurred specifically for the Program, net of any grants, tax credits, or other reductions in cost received by the utility from outside parties and specifically related to the Program.

3. *Low-Income Programs or Low-Income Measures* are DSM or EE Programs or DSM or EE Measures provided specifically to low-income customers.

4. *Measure* means, with respect to EE, an "energy efficiency measure," as defined in G.S. 62-133.8(a)(4), that is new within the meaning of G.S. 62-133.9(a); and, with respect to DSM, an activity, initiative, or Program change, that is new under G.S. 62-133.9(a) and is undertaken by an electric power supplier or its customers to reduce electricity use during peak demand periods. DSM includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.

5. *Measurement Unit* means the basic unit that is used to measure and track the (a) incurred costs; (b) NLR; and (c) kilowatt (kW), kilowatt-hour (kWh), and dollar savings, net of net-to-gross effects for DSM or EE Measures installed in each Vintage Year. A Measurement Unit may consist of an individual Measure or bundle of Measures. Measurement units shall be requested by DEP and established by the Commission for each Program in the Program approval process, and shall be subject to modification by the Commission when appropriate. If Measurement Units have not been established for a particular Program, the Measurement Units for that Program shall be the individual Measures, unless the Commission determines otherwise.

6. *Measurement Unit's Life* means the estimated number of years that equipment associated with a Measurement Unit will operate if properly maintained, or activities (services or customer behavior) associated with the Measurement Unit will continue to be cost-effective, unless the Commission determines otherwise.

7. *Net Found Revenues* means any increases in revenues resulting from any activity by DEP's public utility operations that causes a customer to increase demand or energy consumption, whether or not that activity has been approved pursuant to Commission Rule R8-68. The dollar value of Net Found Revenues will be determined in a manner consistent with the determination of the dollar value of NLR provided in Paragraph No. 8 below. In determining which activities produce Net Found Revenues, the

"Decision Tree" attached to this Mechanism as Attachment C will be applied.

8. *Net Lost Revenues (NLR)* means DEP's revenue losses due to new DSM or EE Measures, net of fuel costs and non-fuel variable operating and maintenance expenses avoided at the time of the kilowatt-hour sale(s) lost due to the DSM or EE Measures[1], or in the case of purchased power, in the applicable billing period incurred by DEP. Portfolio Performance Incentives shall not be considered in the calculation of NLR.

9. *Net-to-gross* (NTG) *factor* means an adjustment factor used to compute the net kW/kWh savings by accounting for behavioral effects, including, but not limited to, free ridership, moral hazard, free drivers, and spillover.

10. *Portfolio Performance Incentive* (PPI) means a utility incentive payment to DEP as a bonus or reward for adopting and implementing new (as defined in G.S. 62-133.9(a)) EE or DSM Measures and/or Programs. The PPI is based on the sharing of avoided cost savings, net of Program Costs, achieved by those DSM and EE Programs in the aggregate. Such Program Costs will be adjusted as discussed elsewhere in this Mechanism. PPI excludes NLR.

11. *Program* means one or more new DSM or EE Measures with similar objectives that have been consolidated for purposes of delivery, administration, and cost recovery, and that were adopted on or after January 1, 2007, including subsequent changes and modifications.

12. *Program Costs* are costs that are directly attributable or reasonably and appropriately allocable to specific DSM or EE Programs or groups of Programs (for purposes of setting the DSM/EE and DSM/EE EMF riders), and include all Incremental Program Costs, and reasonably assigned or allocated administrative and general expenses and other Common Costs, net of any reasonably assigned or allocated grants, tax credits, Program Cost adjustments as discussed elsewhere in this Mechanism, or other reductions in cost received by the utility from outside parties.

13. *Total Resource Cost* (TRC) *test* means a cost-effectiveness test that measures the net costs of a DSM or EE Program or portfolio as a resource option based on the incremental costs of the Program or

[1] Avoided fuel costs would technically be measured at the marginal cost of fuel avoided at the time of the lost kWh sale. However, because fuel costs themselves are subject to true-up, it is administratively easier and results in the same overall revenue requirement outcome to measure fuel costs associated with NLR at the then-current approved prospective fuel and fuel-related cost factor.

portfolio, including both the participants' costs and the utility's costs (excluding incentives paid by the utility to or on behalf of participants). The benefits for the TRC test are the avoided supply costs (i.e., the reduction in generation capacity costs, transmission and distribution capacity costs, and energy costs), valued at marginal cost for the periods when there is a load reduction. The avoided supply costs shall be calculated using net Program or portfolio savings (i.e., savings net of reductions in energy use (NTG impacts) that would have happened even in the absence of the Program). The costs for the TRC test are the incremental Program or portfolio costs paid by the utility and the incremental costs paid by the participants, plus the increased supply costs for any periods in which load is increased. All costs of equipment, installation, operation and maintenance (O&M), removal (less salvage value), and administration, no matter who pays for them, are included in this test. However, Common Costs shall not be included in a Program-level TRC test used for program approval purposes, but shall be included in a portfolio-level TRC test. Any grants, tax credits, or other reductions in cost received by the utility or participants from outside parties and specifically related to the Program or portfolio, as applicable, are considered a reduction to costs in this test.

14. *Utility Cost Test* (UCT) means a cost-effectiveness test that measures the net costs of a DSM or EE Program or portfolio as a resource option based on the incremental costs incurred by the utility (including incentive costs paid by the utility to or on behalf of participants) and excluding any net costs incurred by the participants. The benefits for the UCT are the avoided supply costs (i.e., the reduction in generation capacity costs, transmission and distribution capacity costs, and energy costs), valued at marginal cost for the periods when there is a load reduction. The avoided supply costs shall be calculated using net Program or portfolio savings (i.e., savings net of reductions in energy use (NTG impacts) that would have happened even in the absence of the Program or portfolio). The costs for the UCT are the net Program or portfolio Costs incurred by the utility and the increased supply costs for any period in which load is increased. Utility costs include initial and annual costs, such as the cost of utility equipment, O&M, installation, Program or portfolio administration, incentives paid to or on behalf of participants, and participant dropout and removal of equipment (less salvage value). However, Common Costs shall not be included in a Program-level UCT test used for program approval purposes, but shall be included in a portfolio-level UCT test. Any grants, tax credits, or other reductions in cost received by the utility from outside parties and specifically related to the Program are considered a reduction to costs in this test.

15. *Vintage Year* means an identified 12-month period in which a specific DSM or EE Measure is installed for an individual participant or group of participants.

<u>Application for Approval of Programs</u>

16. In evaluating potential DSM/EE Measures and Programs for selection and implementation, DEP will first perform a qualitative measure screening to ensure Measures are:

    (a) Commercially available and sufficiently mature;
    (b) Applicable to the DEP service area demographics and climate; and
    (c) Feasible for a utility DSM/EE Program.

17. DEP will then further screen EE and DSM Measures for cost-effectiveness. For purposes of this screening, estimated incremental EM&V costs attributable to the Measures shall be included in the Measures' costs. With the exception of Measures included in a Low-Income Program, or other Program in which PPI incentives are not requested that may potentially be filed with the Commission for approval, an EE or DSM Measure with a TRC test result less than 1.0 will not be considered further, unless the Measure can be bundled into an EE or DSM Program to enhance the overall cost-effectiveness of that Program. Consistent with DEP's agreement with Piedmont Natural Gas and Public Service Company of NC, all EE and DSM Measures associated with an end-use that can be served by natural gas must pass the UCT.

18. With the exception of Low-Income Programs or other programs explicitly identified at the time of the application for their approval, all Programs submitted for approval will have a Program-level TRC and UCT test result greater than 1.00. For purposes of determining these test results, estimated incremental EM&V costs attributable to each Program shall be included in the Program costs. DEP will comply, however, with Commission Rule R8-60(i)(6)(iii), which requires DEP to include in its biennial Integrated Resource Plan, revised as applicable in its annual report, certain information regarding the Measures and Programs that it evaluated but rejected.

19. If a Program fails the economic screening in Paragraph 18 above, DEP will determine if certain Measures can be removed from the Program to satisfy the criteria established in Paragraph 18.

20. DEP will provide its Stakeholder Collaborative with information relating to Programs and Measures either currently being considered or planned for future consideration. DEP will also seek suggestions from its Collaborative for additional Programs and Measures for its future consideration.

21. Nothing in this Mechanism relieves DEP from its obligation to comply with Commission Rule R8-68 when filing for approval of DSM or EE Measures or Programs. As specifically required by Commission Rule R8-68(c)(3)(iii), DEP shall, in its filings for approval of Measures and Programs, describe the industry-accepted methods to be used to collect and analyze data; measure and analyze Program participation; and evaluate, measure, verify, and validate the energy and peak demand savings. In its filings, DEP shall also provide a schedule for reporting the results of this EM&V process to the Commission. The EM&V process description should describe not only the methodologies used to produce the impact estimates utilized, but also any methodologies the Company considered and rejected. Additionally, where known, DEP shall identify the independent third party it plans to use for purposes of EM&V, and include an estimate of all third-party costs in its filing. If not known at the time of filing for approval, the information shall be provided at the time of DEP's next annual rider filing.

Program Management

22. In each annual DSM/EE cost recovery filing, DEP shall (a) perform prospective cost-effectiveness test evaluations for each of its approved DSM and EE Programs, (b) perform prospective aggregated portfolio-level cost-effectiveness test evaluations for its approved DSM/EE Programs (including any assigned or allocated administrative and general or other common costs), and (c) include these prospective cost-effectiveness test results in its DSM/EE rider application along with a discussion of whether those results indicate that any of the Programs should be discontinued or modified.

23. DEP will seek to leverage available state and federal funds to operate effective efficiency Programs. Its application for such funds will be transparent with respect to the cost, operation, and profitability of Programs operated with those funds in a manner consistent with its authorized revenue recovery mechanism. Use of such funds helps offset the participant's project costs and is supplemental to DEP's incentives to participants. As such, these funds will not change the impacts or Program- or portfolio-level cost-effectiveness of DEP's Programs as

calculated using the UCT. Further, the amount of avoided costs recognized by the Company will not be reduced if participants also use state or federal funds to offset any portion of their project costs.

Program Modifications

24. Modifications to Commission approved DSM/EE Programs will be considered as provided for in Attachment A to this Mechanism.

Stakeholder Collaborative

25. DEP will conduct periodic collaborative stakeholder meetings for the purpose of collaborating on new Program ideas, reviewing modifications to existing Programs, ensuring an accurate public understanding of the Programs and funding, reviewing the EM&V process, giving periodic status reports on Program progress, helping to set EM&V priorities, providing recommendations for the submission of applications to revise or extend Programs and rate structures, and guiding efforts to expand cost-effective Programs for low-income customers.

26. The Collaborative should continue to be comprised of a broad spectrum of regional stakeholders that represent a balanced interest in the Company's DSM/EE effort and its impacts, as well as national or regional EE advocates and experts. The collaborative will continue to determine its own rules of operation, including the process for setting the agendas and activities of the group, consistent with these terms. Members agree to participate in the advisory group in good faith consistent with mutually-agreed upon rules of participation. Meetings are open to additional parties who agree to the participation rules.

27. DEP will provide information related to the development of EE and DSM to stakeholders in a transparent manner. The Company agrees to disclose Program-related data at a level of detail similar to that which it has disclosed in other states or as disclosed by other regulated utilities in the Carolinas. The Company will share all aspects of the development and evaluation of Programs, including the EM&V process.

28. At its discretion, the Company may require confidentiality agreements with members who wish to review confidential data or any calculations that could be used to determine the data. Disclosure of this data would harm DEP competitively and could result in financial harm to its customers. Participation in the advisory group shall not preclude any party from participating in any Commission proceedings.

Distribution System Demand Response (DSDR) Program

29. The DSDR Program is a new EE Program as defined by G.S. 62-133.8 and G.S. 62-133.9, and is eligible for recovery of reasonable and prudent costs, as well as NLR, subject to the terms and conditions of NLR set forth herein. The DSDR Program is not eligible for recovery of a PPI.

30. The rate of return on investment used to determine the DSDR Program capital-related costs included in each annual rider will be based on the then-current capital structure, embedded cost of preferred stock, and embedded cost of debt of the Company (net of appropriate income taxes), and the cost of common equity approved in the Company's then most recent general rate case.

Evaluation, Measurement and Verification

31. The EM&V of Programs will be conducted using a nationally-recognized protocol to ensure that Programs remain cost-effective. Except for DEP's DSDR Program, EM&V of Programs will be conducted by an independent third-party. EM&V of the DSDR Program will be conducted by DEP. EM&V protocol may be modified with approval of the Commission to reflect the evolution of best practices.

32. EM&V will be applied in accordance with the provisions of Attachment B to this Mechanism.

33. EM&V will also include updates of any NTG factors related to previous NTG estimates for Programs and Measures. All of the updated information will be used in evaluating the continued cost-effectiveness of existing Programs and portfolio. Updates to NTG estimates will be applied consistent with the application of EM&V results pursuant to Attachment B to this Mechanism, but updates to NTG estimates will not be applied retrospectively to Measures that have already been installed or Programs that have already been completed. If it becomes apparent during the implementation of a Program that NTG factors are substantially different than anticipated, the Company will file appropriate Program adjustments with the Commission.

<u>Opt-Out Eligibility Requirement for Industrial Customers and Certain Commercial Customers</u>

34. Commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers who implement or will implement alternative DSM/EE Measures may, consistent with Commission Rule R8-69(d), elect to not participate in any utility-offered DSM/EE Measures and, after written notification to the utility, will not be subject to the DSM/EE rider and DSM/EE EMF rider. For purposes of application of this option, a customer is defined to be a metered account billed under a single application of a Company rate tariff. For commercial accounts, once one account meets the opt-out eligibility requirement, all other accounts billed to the same entity with lesser annual usage located on the same or contiguous properties are also eligible to opt-out of the DSM/EE rider and DSM/EE EMF rider. Since these rates are included in the rate tariff charges, customers electing this option shall receive a DSM and/or EE credit on their monthly bill statement.

35. Opt-out eligible customers that have received DSM/EE Program incentives will be subject to the applicable DSM/EE rider and DSM/EE EMF rider billings for a period of no less than 36 months.

36. Eligible non-residential customers may opt out of either or both of the DSM and EE categories of Programs as well as opt back into either or both. If a customer receives Program incentives from a Company DSM or EE Programs, that customer must opt-in for a period of no less than 36 months. A customer receiving Program incentives from a DSM Program will be required to pay the DSM portion of the DSM/EE Rider for a period of not less than 36 months. A customer receiving Program incentives from an EE Program will be required to pay the EE portion of the DSM/EE Rider for a period of not less than 36 months.

<u>Procedural Matters and General Structure of Riders</u>

37. Beginning in DEP's 2015 DSM/EE rider proceeding, the rate period for the proposed DSM/EE Rider will be the calendar year (i.e., for that proceeding, the period January 1, 2016 through December 31, 2016) (if necessary, the rate period may be expanded to include the month of December 2014). Also beginning in DEP's 2015 DSM/EE rider proceeding, the test period used in the development of the DSM/EE EMF Rider will be the calendar year (i.e., in that proceeding, January 1 through December 31, 2014, adjusted to ensure no double recovery of 2014 DSM/EE Program Costs).

38. For purposes of measuring the cost-effectiveness of Programs and for calculation of the PPI, a Vintage Year will be equivalent to a calendar year.

39. Beginning with DEP's 2015 DSM/EE rider proceeding, the annual filing date of DEP's DSM/EE rider application, supporting testimony, and Exhibits will be no later than June 30 of each calendar year.

40. The hearing to consider the proposed DSM/EE and DSM/EE EMF riders proposed by DEP will be held not less than 90 days after the filing date of the Company's application, supporting testimony, and Exhibits.

41. All DSM/EE and DSM/EE EMF riders shall be calculated and charged to customers based on the revenue requirements associated with DSM and EE Programs. Separate DSM/EE and DSM/EE EMF riders shall be calculated for the Residential customer class, the Non-Residential customer classes, and the Lighting class.

42. One integrated (prospective) DSM/EE rider and one integrated DSM/EE EMF rider shall be calculated for the Residential class and the Residential portion of the Lighting class, respectively, to be effective each rate period. The integrated Residential and Lighting class DSM/EE EMF riders shall include true-ups of estimated DSM/EE costs when actual test period costs become available.

43. Beginning with charges on January 1, 2016, separate DSM and EE billing factors will be available to Non-Residential opt-out-eligible customers. Additionally, the Non-Residential DSM and EE rates and the DSM and EE EMF billing factors will be appropriately considered in each proceeding, so that the factors can be appropriately charged to Non-Residential opt-out eligible customers.

44. For purposes of normalizing or forecasting kWh sales for its annual DSM/EE and DSM/EE EMF rider filing, DEP shall calculate customer growth, weather normalization, and other applicable adjustments on the basis of the test period and/or rate period for each annual filing, as applicable.

<u>Allocation Methodologies</u>

45. Unless the Commission determines otherwise in a G.S. 62-133.9 DSM/EE rider (or other) proceeding:

(a) The Program Costs of an approved DSM or EE Program will be allocated to the North Carolina and South Carolina retail jurisdictions and will only be recovered from those customer classes to which the Program is targeted.

(b) No Program Costs of any approved DSM or EE Program will be allocated to the wholesale jurisdiction.

(c) For EE Programs, the costs of each Program will be allocated based on the annual energy requirements of North Carolina and South Carolina retail customers (at the generator), as reflected in the annual cost of service studies.

(d) For DSM Programs, the aggregated costs of DSM Programs will be allocated based on the annual summer coincident peak demand of North Carolina and South Carolina retail customers, as reflected in the annual cost of service studies.

(e) The allocation factors and inputs used to allocate the estimated rate period costs of DSM and EE Programs shall be those drawn from the most recently filed cost of service study at the time the annual cost recovery filing is made. The allocations of costs shall be trued up at the time that finalized and trued-up costs for a given test period are initially passed through the DSM/EE EMF, using the most recently filed cost of service study at the time the filing is made (but for no later year than the period being trued up). For subsequent true-ups of that period, the cost of service study used will be the same as that used for the initial true-up.

(f) For purposes of recovery through the DSM/EE and DSM/EE EMF riders, the Company's North Carolina retail jurisdictional costs for approved DSM and EE Programs and Measures shall be assigned or allocated to North Carolina retail customer classes by directly assigning the North Carolina retail jurisdictional costs to the customer group to which the Program is offered. For the DSDR Program, North Carolina retail jurisdictional amounts shall be allocated to customer classes on the basis of the energy requirements of each class, drawn from the most recently filed cost of service study at the time the annual cost recovery filing is made (adjusted to exclude the energy requirements of opted-out customers). The process of estimating and truing up the class assignments and allocations will be the same as practiced for jurisdictional allocations.

Cost Recovery

46. In general, as provided in Commission Rule R8-69 and G.S. 62-133.9(d), but subject to the specific provisions and/or modifications contained in this Mechanism, DEP shall be allowed to recover, through the DSM/EE

rider, all reasonable and prudent Program Costs reasonably and appropriately estimated to be incurred in expenses, during the current rate period, for DSM and EE Programs that have been approved by the Commission under Rule R8-68. As permitted by G.S. 62-133.9(d), any of the Stipulating Parties may propose a procedure for the deferral and amortization in future DSM/EE riders of all or a portion of DEP's reasonable and prudent non-capital Program Costs to the extent those costs are intended to produce future benefits. DEP shall be allowed to amortize any costs so deferred over a period of time not to exceed 10 years, unless the Commission determines otherwise.

47. Pursuant to Commission Rule R8-69(b)(6), except for administrative and general expenses (addressed in Paragraph No. 50 below), DEP shall be allowed to earn a rate of return at the overall weighted average net-of-tax rate of return approved in DEP's most recent general rate case on all such unamortized deferred costs (net of income taxes). The return so calculated will be adjusted in any rider calculation to reflect necessary recoveries of income taxes. Pursuant to Commission Rule R8-69(c)(3), the Company is not allowed to accrue a return on NLR or the PPI.

48. With regard to Program Costs incurred prior to January 1, 2016, said costs will be recovered using existing amortization rates, until such time that those deferred costs are recovered, in their entirety, through the DSM/EE cost recovery clause, unless the Parties recommend, and the Commission approves, a different treatment.

49. Beginning in vintage (calendar) year 2016, DEP may recover, subject to approval by the Commission in the annual DSM/EE rider proceedings, Program Costs incurred, without deferral for amortization in future DSM/EE riders, even if Program Costs incurred for the same Program in prior years have been deferred and amortized.

50. To the extent DEP chooses to defer and amortize in future DSM/EE riders the Program Costs for a Program pursuant to Paragraph No. 46 above, non-incremental administrative and general costs reasonably assigned or allocated to, but not directly related to, that Program will be deferred and amortized over a period not to exceed three years, unless the Commission determines otherwise. Pursuant to Commission Rule R8-69(b)(6), DEP shall be allowed to earn a rate of

general rate case on all such unamortized deferred administrative and general costs (net of income taxes). The return so calculated will be adjusted in any rider calculation to reflect necessary recoveries of income taxes. However, irrespective of the prospective treatment of Program

Costs in calendar year 2016 or afterwards, previously deferred administrative and general costs will be recovered using existing amortization rates, until such time that those deferred costs are recovered, in their entirety, through the DSM/EE cost recovery clause, unless the parties recommend, and the Commission approves, a different treatment.

51. The DSM/EE EMF rider shall reflect the difference between the reasonable and prudent Program Costs incurred or amortized during the applicable test period and the revenues actually realized during such test period under the DSM/EE rider then in effect.

52. For Program Costs not deferred for amortization in future DSM/EE riders, the accrual of a return on any under-recoveries or over-recoveries of cost will follow the requirements of Commission Rule R8-69(b), subparagraphs (3) and (6), unless the Commission determines otherwise.

53. The cost and expense information filed by DEP pursuant to Commission Rules R8-68(c) and R8-69(f) shall be categorized by Measurement Unit or Program, as applicable, and period, consistent with the presentation included in the Company's application.

Net Lost Revenues (NLR)

54. When authorized pursuant to Commission Rule R8-69(c) and unless the Commission determines otherwise in a G.S. 62-133.9 DSM/EE rider proceeding, DEP shall be permitted to recover, through the DSM/EE and DSM/EE EMF riders, NLR associated with the implementation of approved DSM and EE Programs, subject to the restrictions set out below.

55. The North Carolina retail kWh sales reductions that result from an approved measurement unit installed in a given Vintage Year shall be eligible for use in calculating NLR eligible for recovery only for the first 36 months after the installation of the Measurement Unit. Thereafter, such kWh sales reductions will not be eligible for calculating recoverable NLR for that or any other Vintage Year.

56. Programs or Measures with the primary purpose of promoting general awareness and education of EE and DSM activities, as well as research and development activities, are ineligible for the recovery of NLR.

57. In order to recover estimated NLR associated with a Pilot Program or Measure, DEP must, in its application for program or measure approval,

demonstrate (a) that the program or measure is of a type that is intended to be developed into a full-scale, Commission-approved program or measure, and (b) that it will implement an EM&V plan based on industry-accepted protocols for the program or measure. No pilot program or measure will be eligible for NLR recovery upon true-up unless it (a) is ultimately proven to have been cost-effective, and (b) is developed into a full-scale, commercialized program.

58. Notwithstanding the allowance of 36 months' NLR associated with eligible kWh sales reductions, the kWh sales reductions that result from measurement units installed shall cease being eligible for use in calculating NLR as of the effective date of (a) a Commission-approved alternative recovery mechanism that accounts for the eligible NLR associated with eligible kWh sales reductions, or (b) the implementation of new rates approved by the Commission in a general rate case or comparable proceeding to the extent the rates set in the general rate case or comparable proceeding are set to explicitly or implicitly recover the NLR associated with those kWh sales reductions.

59. Overall recoverable NLR as measured for the 36-month period identified in Paragraph 55 above shall be reduced by any increases in Net Found Revenues during the same periods.

60. Recoverable NLR shall ultimately be based on kWh sales reductions and kW savings verified by the EM&V process and approved by the Commission. Recoverable NLR shall be estimated and trued-up, on a Vintage Year basis, in the following manner:

(a) As part of the DSM/EE rider approved in each annual cost and incentive recovery proceeding, DEP shall be allowed to recover the appropriate and reasonable level of recoverable NLR associated with each applicable program and Vintage Year (subject to the limitations set forth in this Mechanism), estimated to be experienced during the rate period for which the DSM/EE rider is being set.

(b) NLR related to any given program/measure and Vintage Year shall be trued-up through the DSM/EE EMF rider in subsequent annual cost and incentive recovery proceedings based on the Commission-approved results of the appropriate EM&V studies related to the program/measure and Vintage Year. The true-up shall be based on verified savings and shall be applied to prospective and past time periods in accordance with the Evaluation, Measurement, and Verification section of this Mechanism.

(c) The true-up shall be calculated based on the difference between projected and actual recoverable NLR for each Program and period under consideration, accounting for any differences derived from the completed and reviewed EM&V studies, including: (1) the projected and actual number of installations per Measurement Unit; (2) the projected and actual net kilowatt-hour (kWh) and kilowatt (kW) savings per installation; (3) the projected and actual gross lost revenues per kWh and kW saved; and (4) the projected and actual deductions from gross lost revenues per kWh and kW saved.

(d) The reduction in NLR due to Net Found Revenues shall be trued up in a manner consistent with the true-up of NLR.

(e) The combined total of all Vintage Year true-ups calculated in a given year's Commission Rule R8-69 proceeding shall be incorporated into the appropriate DSM/EE EMF billing factor.

<u>Portfolio Performance Incentive (PPI)</u>

61. When authorized pursuant to Commission Rule R8-69(c), DEP shall be allowed to collect a PPI for its DSM/EE portfolio for each Vintage Year, separable into Residential, Lighting, Non-Residential DSM, Non-Residential EE categories. The PPI shall be subject to the restrictions set out below.

62. Programs, Measures, and activities undertaken by DEP with the primary purpose of promoting general awareness of and education about EE and DSM activities, as well as research and development activities, that are not directly associated with a Commission approved EE or DSM Program, will not be included in the portfolio for purposes of the PPI calculation.

63. Unless (a) the Commission approves DEP's specific request that a pilot program or measure be eligible for PPI inclusion when DEP seeks approval of that program or measure, and (b) the pilot is ultimately commercialized, pilot programs or measures are ineligible for and will not be factored into the calculation of the PPI.

64. Low-Income Programs or other programs explicitly approved with expected UCT results less than 1.00 shall not be included in the portfolio for purposes of the PPI calculation.

65. The PPI shall be based on the net dollar savings of DEP's DSM/EE portfolio, as calculated using the UCT. The North Carolina retail jurisdictional and class portions of the system-basis net dollar savings

shall be determined in the same manner as utilized to determine the North Carolina retail jurisdictional and class portions of recoverable system costs. The PPI for each Vintage Year shall be incorporated into DEP's DSM/EE or DSM/EE EMF billing factors, as appropriate.

66. In its annual filing, pursuant to Commission Rule R8-69(f), DEP shall indicate, for each Program or Measure for which it seeks PPI inclusion, the annual projected and actual utility costs, participant costs, number of Measurement Units installed, per kW and kWh impacts for each Measurement Unit, and per kW and kWh avoided costs for each Measurement Unit, consistent with the UCT, related to the applicable Vintage Year installations that it requests the Commission to approve. Upon its review, the Commission will make findings based on DEP's annual filing for each Program or Measure which is included in an estimated or trued-up PPI calculation for any given Vintage Year.

67. Unless the Commission determines otherwise in a G.S. 62-133.9 DSM/EE rider proceeding, the amount of the pre-income-tax PPI initially to be recovered in a Vintage Year for the entire DSM/EE portfolio, excluding Programs not eligible for a PPI, shall be equal to 11.75% multiplied by the present value of the estimated net dollar savings associated with the portfolio installed in that Vintage Year, calculated by Program using the UCT (and excluding Low Income Programs). The present value of the estimated net dollar savings shall be the difference between the present value of the annual lifetime avoided cost savings for measurement units projected to be installed in that Vintage Year and the present value of the annual lifetime program costs for those measurement units. The annual lifetime avoided cost savings for measurement units installed in the applicable Vintage Year shall be calculated by multiplying the number of each specific type of Measurement Unit projected to be installed in that Vintage Year by the most current estimates of each lifetime year's per installation kW and kWh savings and by the most current estimates of each lifetime year's per kW and kWh avoided costs. In calculating the forecasted initial PPI it will be assumed that projections will be achieved.

68. Unless the Commission determines otherwise in a G.S. 62-133.9 DSM/EE rider proceeding, the PPI for vintage periods subsequent to the approval of this mechanism shall be converted into a stream of no more than 10 levelized annual payments, accounting for and incorporating DEP's overall weighted average net-of-

tax rate of return approved in DEP's most recent general rate case as the appropriate discount rate. Levelized annual payments applicable to Programs in prior vintage periods will continue until all such amounts are recovered.

69. For the PPI for Vintage Year 2016, the per kW avoided capacity costs used to calculate avoided cost savings shall be the avoided capacity cost rates approved by the Commission for DEP in the most recent biennial avoided cost proceeding as of the date of the filing of the 2015 DSM/EE cost and incentive recovery proceeding. The per kWh avoided energy costs shall be those reflected in or underlying the most recently filed integrated resource plan (IRP).

70. For the PPI for Vintage Years after 2016, the presumptive per kW avoided capacity costs and per kWh avoided energy costs used to calculate avoided cost savings shall be those determined pursuant to Paragraph 69 above. However, if at the time of initial estimation of the PPI for each vintage year after 2016, either (a) the Company's per kWh avoided energy costs calculated for the purposes of the Company's annual IRP or resource plan update filings have increased or decreased by 20% or more or (b) the Company's per kW avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings have increased or decreased by 15% or more, the avoided costs (both energy and capacity) will be updated for purposes of the DSM/EE rider proceeding.

71. The per kW avoided transmission and avoided distribution (avoided T&D) costs used to calculate net savings for a Vintage Year shall be based on the study update at least every two years only if the study update results in a 20% change from the prior study's avoided T&D costs.

72. Unless DEP and the Public Staff agree otherwise, DEP shall not be allowed to update its avoided capacity costs and avoided energy costs after filing its annual cost and incentive recovery application for purposes of determining the DSM/EE and DSM/EE EMF riders in that proceeding.

73. DEP and the Public Staff will study the issue of the appropriate avoided T&D costs to be used in the Company's calculations of cost-effectiveness and achieved net dollar savings, and, if appropriate, recommend in the Company's 2015 DSM/EE rider proceeding adjustments to the avoided T&D cost rates filed in this proceeding, to be made on a prospective basis for vintage (calendar) year 2016. However, for purposes of the Mechanism, the Parties agree that the Company's initially proposed avoided T&D cost rates are reasonable for Vintage Year 2015. The Company and the Public Staff have agreed to utilize methods and assumptions similar to those utilized in the ongoing joint effort between the Public Staff and Duke Energy Carolinas, LLC, to the extent it is reasonable to do so.

74. When DEP files for its annual cost recovery under Commission Rule R8-69, it shall comply with the filing requirements of Commission Rule R8-69(f)(1)(iii), reporting all interim measurement and verification data, even if that data is not final, to assist the Commission and the Public Staff in their review and monitoring of the impacts of the DSM and EE Measures.

75. The PPI for each Vintage Year shall ultimately be based on net dollar savings as verified by the EM&V process and approved by the Commission. The PPI for each Vintage Year shall be trued-up as follows:

(a) As part of the DSM/EE rider approved in each annual cost and incentive recovery proceeding, DEP shall be allowed to recover an appropriately and reasonably estimated PPI (subject to the limitations set forth in this Mechanism) associated with the Vintage Year covered by the rate period in which the DSM/EE rider is to be in effect.

(b) The PPI related to any given Vintage Year shall be trued-up through the DSM/EE EMF rider in subsequent annual cost and incentive recovery proceedings based on the Commission-approved results of the appropriate EM&V studies related to the program/measure and Vintage Year, as determined pursuant to the EM&V Agreement. The true-up shall be based on verified savings and shall be applied to prospective and past time periods in accordance with the Evaluation, Measurement, and Verification section of this Mechanism.

(c) The amount of the PPI ultimately to be recovered for a given Vintage Year shall be based on the present value of the actual net dollar savings derived from all Measurement Units installed in that Vintage Year, as associated with each DSM/EE program offered during that year (excluding Low Income Programs), and calculated by DSM/EE program using the UCT. The present value of the actual net dollar savings shall be the difference between the present value of the annual lifetime avoided cost savings for measurement units installed in that Vintage Year and the present value of the annual lifetime program costs for those measurement units. The annual lifetime avoided cost savings for Measurement Units installed in the applicable Vintage Year shall be calculated by multiplying the number of each specific type of Measurement Unit installed in that Vintage Year by each lifetime year's per installation kW and kWh savings (as verified by the appropriate EM&V study pursuant to the EM&V agreement) and by each lifetime year's per kW and kWh avoided costs as determined when calculating the initially estimated PPI for the Vintage Year. The

Stipulating Parties agree to make all reasonable efforts to ensure that all vintages are fully trued-up within 24 months of the vintage program year.

76. The combined total of all Vintage Year true-ups of the PPI calculated in a given year's Rule R8-69 proceeding shall be incorporated into the appropriate DSM/EE EMF billing factor.

77. The PPI for each vintage year shall be allocated to DSM and EE programs in proportion to the present value net dollar savings of each program for the vintage year, as calculated pursuant to the method described herein.

Additional Incentive

78. As further incentive to motivate the Company to aggressively pursue offering available cost-effective EE and DSM Programs, if the Company achieves incremental energy savings of 1% of the prior year's DEP system retail electricity sales in any year during the five-year 2015-2019 period, the Company will receive a bonus incentive of $400,000 for that year. The Company is eligible to receive the bonus incentive each year during the five-year 2016-2020 period. Verification of this achievement will be obtained through the EM&V process discussed elsewhere in this Mechanism.

Financial Reporting Requirements

79. In its quarterly ES-1 Reports to the Commission, DEP shall calculate and present its primary North Carolina retail jurisdictional earnings by including all actual EE and DSM Program revenues, including PPI and NLR incentives, and costs. Additionally, DEP shall prepare and present (1) supplementary schedules setting forth the Company's North Carolina retail jurisdictional earnings excluding the effects of the PPI; (2) supplementary schedules setting forth the Company's North Carolina retail jurisdictional earnings excluding the effects of its EE and DSM Programs; (3) supplementary schedules setting forth earnings, including overall rates of return and returns on common equity actually realized from DEP's EE and DSM Programs in total and stated separately by Program Class (Program Classes are hereby defined to be (a) EE Programs and (b) DSM Programs); and (4) supplementary schedules setting forth earnings, including overall rates of return and returns on common equity actually realized from DEP's (a) DSDR Program and (b) all other Programs, collectively, in the EE Program Class. (Show DSDR Program returns and all other collective EE Program returns separately.)

Detailed workpapers shall be provided for each scenario described above. Such workpapers, at a minimum, shall clearly show actual revenues; expenses; taxes; operating income; rate base/investment, including components; and the applicable capitalization ratios and cost rates, including overall rate of return and return on common equity.

Review of Mechanism

80. The terms and conditions of this Mechanism shall be reviewed by the Commission every four years unless otherwise ordered by the Commission. However, a Stipulating Party may request the Commission to initiate such a review at any time within the four year period. The Company and other parties shall submit any proposed changes to the Commission for approval at the time of the filing of the Company's annual DSM/EE rider filing. During the time of review, the Mechanism shall remain in effect until further order of the Commission revising the terms of the Mechanism or taking such other action as the Commission may deem appropriate.

Term

81. This Mechanism shall continue until terminated pursuant to Order of the Commission.

Attachment A

The table below groups program changes into three categories: (1) those that should require regulatory approval by the North Carolina Utilities Commission (NCUC) prior to implementation, (2) those that should not require Commission approval but should require advanced notification to be filed with the Commission prior to making the program change, and (3) those that simply require inclusion in a quarterly report that will notify the Commission of all program changes made without Commission approval or advance notice. The Company will continue to share potential program changes with the Public Staff and the Collaborative.

Type of Change	Description of Change	Prior NCUC Approval[1]	Advance Notice[2]
Tariff Revision	Any change to a program that is not explicitly allowed by the existing tariff language. Tariffs shall include information pertaining to the availability of, eligibility for, and applicability of the program, identification of specific measures offered, general description of each measure, maximum incentives offered ("up to $__ per customer, measure unit, etc."), and method(s) of measure delivery.	Yes	No
Addition of and Removal from Programs of Measures Actually Offered	The addition of any tariff-authorized measure as an actual offering of a program, and/or the alteration, removal, or replacement of any tariff-authorized measure actually offered as part of a tariffed program, including any such action involving equipment or participant options/choices:		
	1. That is not consistent with the language of the tariff.	Yes	No
	2. That results in the erosion of the forward-looking program-level Total Resource Cost (TRC) test ratio, causing it to fall below 1.00.[3]	Yes	No
	3. That results in a net 20% or more reduction in the forward-looking annual energy kilowatt-hour (kWh) or demand kilowatt (kW) savings associated with the program, as calculated for the next full program year affected by the change.	No	Yes

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[1] Petitions for approval shall be filed no later than 30 days prior to proposed effective date, pursuant to Commission Rule R8-68.

[2] Advance notice shall be filed no later than 45 days prior to proposed effective date.

[3] If inadequate market information exists to develop a reasonable estimate of the TRC test ratio, the Utility Cost Test ratio may be used instead, with the TRC ratio being provided as soon as a reasonable estimate thereof can be determined.

Type of Change	Description of Change	Prior NCUC Approval[1]	Advance Notice[2]
	4. That results in the forward-looking present value of program costs increasing by more than 20%, or the forward-looking program-level TRC test ratio decreasing by more than 20%.[3]	No	Yes
	5. That results in the projected forward-looking net present value avoided costs savings from the program increasing by more than 20%, or the forward-looking program-level TRC test ratio increasing by more than 20%.[3]	No	Yes
	6. That does not fall into one of the five categories above.	No	No[4]
Expansion or Reduction of Population to Which a Measure Will be Offered	Expansion of the offering/availability of a measure to other customer groups as authorized or allowed by the tariff but not previously included, or elimination of the availability of a measure to customer groups previously included:		
	1. That is not consistent with the language of the tariff.	Yes	No
	2. That results in the erosion of the forward-looking program-level TRC test ratio, causing it to fall below 1.00.[3]	Yes	No
	3. That results in the forward-looking present value of program costs increasing by more than 20%, or the forward-looking program-level TRC test ratio decreasing by more than 20%.[3]	No	Yes
	4. That results in the projected forward-looking net present value avoided costs savings from the program increasing by more than 20%, or the forward-looking program-level TRC test ratio increasing by more than 20%.[3]	No	Yes
	5. That does not fall into one of the four categories above.	No	No[4]

[4] Program changes falling into this category shall be set forth in the quarterly Program Modification Report, as noted below.

Type of Change	Description of Change	Prior NCUC Approval[1]	Advance Notice[2]
Changes to Measure Unit Savings or Baseline Standards.	Changes to the unit savings (kWh or kW saved per measurement unit) or efficiency standards for a measure, resulting from technological, regulatory, or other actions or determinations, that alter the incremental and/or baseline energy/load characteristics related to the measure and used to calculate incremental energy/demand savings:		
	1. That result in the erosion of the forward-looking program-level TRC test ratio, causing it to fall below 1.00.[3]	Yes	No
	2. That result in the forward-looking present value of program savings decreasing by more than 20%, or the forward-looking program-level TRC test ratio decreasing by more than 20%.[3]	No	Yes
	3. That result in the projected forward-looking net present value avoided costs savings from the program increasing by more than 20%, or the forward-looking program-level TRC test ratio increasing by more than 20%.[3]	No	Yes
	4. That do not fall into one of the three categories above. Any such changes will be reflected in the next applicable evaluation, measurement, and verification (EM&V) report, provided the change occurred prior to the sample period used for the subsequent EM&V.	No	No[4]
Changes in Participant Incentives	Participant incentives associated with any actually offered measures, shall not exceed the maximum incentive established in the tariff for the measure, on a per customer, kWh, or kW basis. Changes in actually offered participant incentives within the maximum limits set by the tariff:		
	1. That are not consistent with the language of the tariff.	Yes	No
	2. That result in the erosion of the forward-looking program-level TRC test ratio, causing it to fall below 1.00.[3]	Yes	No
	3. That result in the forward-looking present value of program costs increasing by more than 20%, or the forward-looking program-level TRC test ratio of the program decreasing by more than 20%.[3]	No	Yes

Type of Change	Description of Change	Prior NCUC Approval[1]	Advance Notice[2]
	4. That result in the projected forward-looking net present value avoided costs savings from the program increasing by more than 20%, or the forward-looking program-level TRC test ratio increasing by more than 20%.[3]	No	Yes
	5. That do not fall into one of the four categories above.	No	No[4]
Unit of Measure	Changes to the internal tracking of a measure component from the tracking initially established for the measure component.	No	No[4]
Changes in Estimates of Participant Cost	Changes to the estimated participant costs, unless provided for in the Program tariff or resulting from changes identified elsewhere in this table:		
	1. That result in the erosion of the forward-looking program-level TRC test ratio, causing it to fall below 1.00.[3]	Yes	No
	2. That result in the forward-looking program-level TRC test ratio decreasing by more than 20%[3].	No	Yes
	3. That result in the forward-looking program-level TRC test ratio increasing by more than 20%.[3]	No	Yes
	4. That do not fall into one of the three categories above.	No	No[4]
Other Program Changes	Other program changes:		
	1. That are not consistent with the language of the tariff.	Yes	No
	2. That result in the erosion of the forward-looking program-level TRC test ratio, causing it to fall below 1.00.[3]	Yes	No
	3. That result in the forward-looking present value of program costs increasing by more than 20%, or the forward-looking program-level TRC test ratio decreasing by more than 20%.[3]	No	Yes
	4. That result in the projected forward-looking net present value avoided costs savings from the program increasing by more than 20%, or the forward-looking program-level TRC test ratio increasing by more than 20%.[3]	No	Yes

Type of Change	Description of Change	Prior NCUC Approval[1]	Advance Notice[2]
	5. That do not fall into one of the four categories above.	No	No[4]

All program changes which require advance notification shall be filed no later than 45 days prior to the proposed effective date of the change using the Advance Notification Program Modifications Reporting Template. Should any party have concern about the proposed modification, it shall file comments with the Commission within 25 days of the Company's filing of the Advanced Notification Program Modifications Reporting Template. A sample of the Advance Notification Program Modifications Reporting Template is attached. On a quarterly basis, the Company will file with the Commission a notification of program changes that have been made without Commission approval or advance notice, using the Program Modifications Reporting Template attached below.

In addition to the measurements required with respect to the above-described program changes, forward-looking TRC and other cost effectiveness test results shall be provided for review in each annual R8-69 cost recovery proceeding. In the case that a program has experienced a number of separate changes or modifications that have effectively changed the baseline for a program by 15%, a party or intervenor may request that the baseline TRC and other test results be reset for purposes of applying these Flexibility Guidelines. Whenever a change in a program goes into effect as a result of Commission approval or is allowed to go into effect after advance notice, the baseline TRC and other test results will be reset for purposes of applying these Flexibility Guidelines.

With regard to all program changes, neither Commission approval, the filing of advance notice, nor the inclusion of the changes in the quarterly Program Modifications Report precludes any party from taking issue with or the Commission from disallowing or amending a program change in a DSM/EE cost recovery proceeding, DSM/EE program approval proceeding, general rate case proceeding, or a similar proceeding.

For purposes of this discussion:

1. "Program" is defined as a group of DSM/EE measures that are appropriately bundled into a group for purposes of program delivery, marketing, and maximizing energy savings. Tariffs are developed for programs and include the availability and applicability of the program, and the customer eligibility requirements. Cost effectiveness is determined at this level.

2. "Measure" is generally defined as a specific and individual activity or item of equipment that provides energy or demand savings. Examples include refrigerator replacement, HVAC heat pump, central air, ground source, lighting fixtures, LEDs, CFLs, etc. One measure may constitute the measurement unit by which the utility tracks costs and savings, or individual measures may be grouped into a single measurement unit. In each approved program tariff, the maximum incentive for each included measure and/or measurement unit will be set forth.

On a quarterly basis, the Company will file a notification, using the Program Modifications Reporting Template below, with the Commission of all program changes that have been made without Commission approval or advance notice.

The Program Modifications Reporting Template will include the following information:

	Description
Program Name	The name of the program with the recommended or implemented program change.
Description of Change	Details of the change made to the program. For example, the incentive per participant was increased to drive program participation. Although the cost effectiveness per participant declined, the overall program cost effectiveness is expected to increase as a result of more program participants.
Type of Change	Identifies the type of program change made. Refer to the table entitled Type of Programs in this document on page one for a list of types of program changes and description of each change.
Date of Change	The date the change was implemented.
Delta of Change in Cost Effectiveness Test Results	Illustrates the impact that the program change has on the cost effectiveness tests. It reflects the changes in energy savings, program costs and projected

	participation versus what was reflected in the test results that were originally filed.
New Cost Effectiveness Test Results	The new cost effectiveness test scores based on implementation of the proposed program change.
Percent of Change in Program Cost	The percentage of change in program costs reflecting the proposed program change(s).
Absolute Change in Program Costs	The change in program costs reflecting the proposed program change(s).
Percent of Change in Projected Avoided Costs	The percentage of change in projected avoided costs reflecting the proposed program change(s).
Absolute Change in Projected Avoided Costs	The change in projected avoided costs reflecting the proposed program change(s).
Percent of Change in Program Impacts	The percentage of change in projected annual energy and demand savings reflecting the proposed program change(s), as calculated for the next full program year affected by the change.
Absolute Change in Program Impacts	The change in projected annual energy and demand savings reflecting the proposed program change(s), as calculated for the next full program year affected by the change.

Advanced Notification Program Modifications Reporting Template

The Advanced Notification Program Modifications Reporting Template will include the following information as agreed upon by the Parties.

	Description
Program Name	The name of the program with the recommended or implemented program change.
Description of Proposed Change	Details of the proposed program change to be made.
Type of Change	Identifies the type of program change made.
Proposed Effective Date of Change	The proposed date to implement the change

Delta of Change in Cost Effectiveness Test Results	Illustrates the impact that the program change has on the cost effectiveness tests. It reflects the changes in energy savings, program costs and projected participation versus what was reflected in the test results that were originally filed.
New Cost Effectiveness Test Results	The revised cost effectiveness test scores reflecting the proposed program change(s).
Percent of Change in Program Cost	The percentage of change in program costs reflecting the proposed program change(s).
Absolute Change in Program Costs	The change in program costs reflecting the proposed program change(s).
Percent of Change in Projected Avoided Costs	The percentage of change in projected avoided costs reflecting the proposed program change(s).
Absolute Change in Projected Avoided Costs	The change in projected avoided costs reflecting the proposed program change(s).
Percent of Change in Program Impacts	The percentage of change in projected annual energy and demand savings reflecting the proposed program change(s), as calculated for the next full program year affected by the change.
Absolute Change in Program Impacts	The change in projected annual energy and demand savings reflecting the proposed program change(s), as calculated for the next full program year affected by the change.

Program Modifications Reporting Template												
Program Name	Original Offer	Description of Change	Type of Change	Date of Change	Delta of Change				New Cost Effectiveness Test Results			
					UCT	TRC	RIM	Participant	UCT	TRC	RIM	Participant

Advanced Notification Program Modifications Reporting Template																			
Program Name	Description of Proposed Change	Type of Change	Proposed Effective Date of Change	Delta of Change				New Cost Effectives Test Scores				Percent of Change in Program Cost[1]	Absolute Change in Program Cost[1]	Percent of Change in Projected Avoided Cost[1]	Absolute Change in Avoided Cost[1]	Percent of Change in Projected Program Impacts (kWh/kW)	Absolute Change in Program Impacts (kWh/kW)
				UCT	TRC	RIM	Parti-cipant	UCT	TRC	RIM	Partici-pant						

Rationale for Program Change:

[1] Information provided will be marked as confidential.

Attachment B

Initial EM&V results shall be applied retrospectively to program impacts that were based upon estimated impact assumptions derived from industry standards (rather than EM&V results for the program or a similar program offered elsewhere in the Carolinas). For all EE programs without prior EM&V results used as the basis for approval, EM&V results shall be applied retrospectively to the beginning of the program offering. For the purposes of the vintage true-ups, these initial EM&V results will be considered actual results for a program until the next EM&V results are received. The new EM&V results will then be considered actual results going forward and applied prospectively for the purposes of truing up vintages from the first day of the month immediately following the month in which the study participation sample for the EM&V was completed. This EM&V will then continue to apply and be considered actual results until it is superseded by new EM&V results, if any.

For all new programs and pilots, the Company will follow a consistent methodology, meaning that initial estimates of impacts will be used until Duke Energy Progress has valid EM&V results, which will then be applied back retrospectively to the beginning of the offering and will be considered actual results until a second EM&V is performed.

Attachment C

A "decision tree" will be used to evaluate whether activities that may directly or indirectly result in increases in customer demand or energy consumption should be designated by the Company as producing "found revenues" and either filed with the Commission for a determination of their status or reported to the Commission for consideration at its discretion. The Company will create a list of all Duke Energy Progress activities that may produce found revenues by directly or indirectly resulting in an increase in customer demand or energy consumption within the Company's service territory, followed by the elimination, or "filtering out," of activities that meet certain criteria. More specifically, an activity will be eliminated from the list if it meets one or more of the following criteria (the tree itself should be referred to for the precise language of each filter):

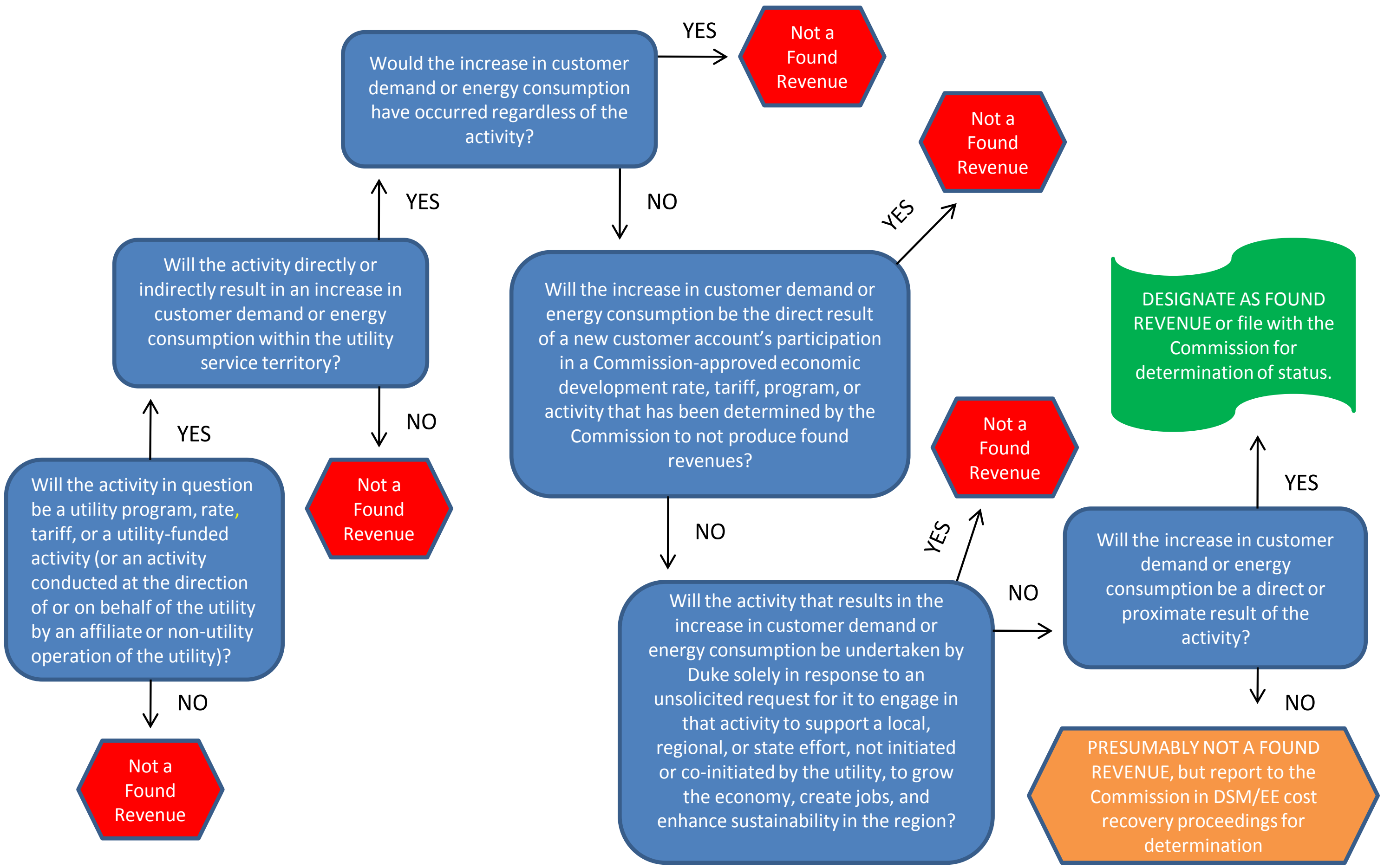
(1) The increase in customer demand or energy consumption would have occurred regardless of the activity.

(2) The increase is the result of a new customer account's participation in certain Duke Energy Progress economic development activities that have been found by the Commission not to result in found revenues.

(3) The activity is conducted at the unsolicited request of a governmental unit for the purposes of growing the economy, creating jobs, or enhancing sustainability in the region.

If an activity is not eliminated for consideration by one of these filters, Duke Energy Progress will then evaluate whether the related increase in customer demand or energy consumption is a direct or proximate result of the activity. If it is determined to be so, the Company will designate the activity as one producing found revenues or submit it to the Commission for determination; if not, the Company may presume that the activity does not produce found revenues but will report it to the Commission as part of its annual DSM/EE cost recovery filing. A visual representation of the "decision tree" process follows on the next page.

"Net lost revenues shall also be net of any increases in revenues resulting from any activity by the electric public utility that increases customer demand or energy consumption, whether or not that activity has been approved pursuant to this Rule R8-68." - Commission Rule R8-68(b)(5)



DOCKET NO. E-2, SUB 1069

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC,	)	ORDER APPROVING
Pursuant to G.S. 62-133.2 and	)	FUEL CHARGE
NCUC Rule R8-55 Relating to Fuel	)	ADJUSTMENT
and Fuel-Related Charge Adjustments	)	
for Electric Utilities	)	

HEARD: Tuesday, September 15, 2015, at 9:30 a.m. in Commission Hearing Room, 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioner Bryan E. Beatty, Commissioner Susan W. Rabon, Commissioner ToNola D. Brown-Bland, Commissioner Don M. Bailey, Commissioner Jerry C. Dockham and Commissioner James G. Patterson

APPEARANCES:

For Duke Energy Progress, LLC:

Brian L. Franklin, Associate General Counsel, Duke Energy Corporation, 550 South Tryon Street, DEP 45A/PO Box 1321, Charlotte, North Carolina 28201

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolinas Industrial Group for Fair Utility Rates III:

Adam Olls, Bailey & Dixon, L.L.P., 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association:

Peter H. Ledford, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff - North Carolina Utilities Commission, 430 N. Salisbury Street, 4326 MSC, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 17, 2015, Duke Energy Progress, LLC (Duke Energy Progress, DEP, or the Company), filed an application pursuant to G.S. 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Kimberly D. McGee, Swati V. Daji, Joseph A. Miller, Jr., Regis T. Repko, and Kenneth D. Church.

Petitions to intervene were filed by Carolina Industrial Group for Fair Utility Rates III (CIGFUR) on June 19, 2015, by the North Carolina Sustainable Energy Association (NCSEA) on June 30, 2015, and by Carolina Utility Customers Association, Inc. (CUCA) on June 30, 2015. The Commission granted CIGFUR's petition to intervene on June 23, 2015, and NCSEA's and CUCA's petitions to intervene on July 7, 2015.

On June 24, 2015, the Commission entered an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. That Order provided that direct testimony of intervenors should be filed on August 31, 2015, that rebuttal testimony should be filed on September 9, 2015, and that a hearing on this matter would be held on September 15, 2015.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On August 28, 2015, DEP filed the supplemental testimony and revised exhibits and workpapers of Kimberly D. McGee.

On August 31, 2015, the Public Staff filed the affidavits of Darlene P. Peedin and Jay B. Lucas.

On September 1, 2015, DEP and the Public Staff filed a motion requesting that all witnesses be excused from appearance at the evidentiary hearing. On September 3, 2015, the Commission granted the motion, excusing DEP witnesses McGee, Daji, Miller, Repko, and Church, and Public Staff witnesses Peedin and Lucas from appearing at the evidentiary hearing.

On September 3, 2015, DEP filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

The case came on for hearing as scheduled on September 15, 2015. The prefiled direct and supplemental testimony of DEP's witnesses and the prefiled affidavits and exhibits of the Public Staff's witnesses were received into evidence. Three exhibits offered by NCSEA were received into evidence by stipulation of the parties. No other party presented witnesses, and no public witnesses appeared at the hearing.

The Public Staff and DEP filed a joint proposed order and NCSEA filed a brief on October 15, 2015.

Based upon the Company's verified application, the testimony, affidavits, and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Progress is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Progress is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended March 31, 2015 (test period).

3. In its application and direct testimony in this proceeding, DEP requested a total decrease of approximately $180 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEP included Experience Modification Factor (EMF) riders to take into account fuel and fuel-related cost under-recoveries and over-recoveries experienced during the test period, with an overall under-recovery of approximately $69 million.

4. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

5. The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

6. The Company's merger-related fuel savings for the test period as reported in Schedule 11 of the Company's Monthly Fuel Report are reasonable.

7. The test period per book system sales are 57,715,306 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 66,335,921 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	15,011,404
Natural Gas, Oil and Biomass	19,535,270
Nuclear	25,942,058
Hydro – Conventional	596,433
Purchased Power – subject to economic dispatch or curtailment	3,034,255
Other Purchased Power	2,216,501
Total Net Generation	66,335,921

8. The appropriate nuclear capacity factor for use in this proceeding is 94.3%.

9. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 37,993,413 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	16,103,240
Small General Service	1,914,039
Medium General Service	11,152,159
Large General Service	8,378,166
Lighting	445,809
Total	37,993,413

10. The projected billing period (December 2015-November 2016) sales for use in this proceeding are 62,510,062 MWh on a system basis and 37,467,782 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	15,699,600
Small General Service	1,909,694
Medium General Service	10,538,645
Large General Service	8,826,039
Lighting	493,804
Total	37,467,782

11. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 69,978,628 MWh and is categorized as follows:

Generation Type	MWh
Coal	16,739,697
Gas Combustion Turbine (CT) and Combined Cycle (CC)	18,376,760
Nuclear	29,323,747
Hydro	607,739
Purchased Power	4,930,685
Total	69,978,628

12. The appropriate fuel and fuel-related prices and expenses for use in this proceeding to determine projected system fuel expense are as follows:

A. The coal fuel price is $31.84/MWh.
B. The gas CT and CC fuel price is $34.39/MWh.

C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $57,129,387.

D. The total nuclear fuel price (including Joint Owners generation) is $6.86/MWh.

E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $196,182,466.

F. System fuel expense recovered through intersystem sales is $132,620,279.

13. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $899,382,837.

14. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $68,706,211, consisting of under-recoveries of $18,916,298; $2,623,759; $17,127,474; $28,320,778 and $1,717,903, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively.

15. The decrease in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-2, Sub 1045, should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

16. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 2.450¢/kilowatt-hour (kWh) for the Residential class; 2.433¢/kWh for the Small General Service class; 2.433¢/kWh for the Medium General Service class; 2.289¢/kWh for the Large General Service class; and 2.126¢/kWh for the Lighting class.

17. The appropriate EMFs established in this proceeding, excluding the regulatory fee, are as follows: 0.117¢/kWh for the Residential class; 0.137¢/kWh for the Small General Service class; 0.154¢/kWh for the Medium General Service class; 0.338¢/kWh for the Large General Service class; and 0.385¢/kWh for the Lighting class.

18. The total net fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 2.567¢/kWh for the Residential class; 2.570¢/kWh for the Small General Service class; 2.587¢/kWh for the Medium General Service class; 2.627¢/kWh for the Large General Service class; and 2.511¢/kWh for the Lighting class.

19. The restated base fuel and fuel-related cost factors approved in Docket No. E-2, Sub 1045, amounting to 3.013¢/kWh for the Residential class, 3.001¢/kWh for the Small General Service class, 2.921¢/kWh for the Medium General Service class, 2.958¢/kWh for the Large General Service class, and 3.655¢/kWh for the Lighting class, should be adjusted by amounts equal to (0.563)¢/kWh, (0.568)¢/kWh, (0.488)¢/kWh, (0.669)¢/kWh, and (1.529)¢/kWh, respectively (all excluding the regulatory fee). The resulting approved fuel and fuel-related cost factors should be further adjusted by EMF increments totaling 0.117¢/kWh, 0.137¢/kWh, 0.154¢/kWh,

0.338¢/kWh, and 0.385¢/kWh for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting customer classes, respectively (all excluding the regulatory fee).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending March 31 as the test period for DEP. The Company's filing in this proceeding was based on the 12 months ended March 31, 2015.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the Application, the direct and supplemental testimony of Company witness McGee, and the entire record in this proceeding. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is contained in the testimony of Company witnesses Repko and Miller and the affidavit of Public Staff witness Lucas.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC) Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Repko testified that the Company's four nuclear units operated at a system average capacity factor of 96.9% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 91.1%, exceeded the five-year industry weighted average capacity factor of 88.3% for the period 2009-2013 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report.

Witness Repko testified that there was one refueling and maintenance outage during the test period for Brunswick Unit 1, which was completed within a day of the scheduled allocation, and also included various major work items.

Company witness Repko also testified that in February 2014, DEP announced that it had entered discussions regarding the potential purchase of North Carolina Eastern Municipal Power Agency's portions of Brunswick Units 1 and 2, and Harris Unit 1. He stated that the purchase, when closed, would bring DEP's ownership to 100% of these units and add 493 megawatts (MW) to DEP's nuclear portfolio.

Company witness Miller testified concerning the performance of DEP's fossil/hydro assets. He stated that the primary objective of the Company's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEP's customers, and that it achieves this objective by focusing on a number of key areas. Witness Miller further stated that environmental compliance is a "first principle" and that DEP achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers.

Company witness Miller testified that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate operational performance, depending on the generator type: (1) equivalent availability factor (EAF), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned maintenance (*i.e.*, forced outage time); (2) equivalent forced outage rate (EFOR), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated[1] hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and (3) starting reliability (SR), which represents the percentage of successful starts.

Company witness Miller testified that the DEP fossil/hydro fleet responded to the test period summer and winter peaks with a very strong performance. He testified that DEP customers established an all-time peak demand during the test period in the months of January and February 2015. The January 8, 2015 record of 14,519 MW was broken on the morning of February 20, 2015 with a new record demand of 15,569 MW. Witness Miller presented the following chart, which shows operation results, as well as results from the most recently published NERC Generating Availability Brochure for the period 2009 through 2013, and is categorized by generator type:

[1] Derated hours are hours the unit operation was less than full capacity.

Generator Type	Measure	Review Period	2009-2013	Nbr of Units
		Operational Results	NERC Average	
Coal-fired Review Period	EAF	84.7%	83.1%	470
	EFOR	1.59%	7.3%	
2014 Summer Peak	Coal-fired EAF	95.7%	n/a	n/a
	Combined Cycle EAF	99.0%	n/a	n/a
Total CC Average	EAF	89.49 %	85.3%	323
	EFOR	1.1%	6.3%	
Total CT Average	EAF	91.23%	87.9%	934
	SR	98.15%	97.5%	
Hydro	EAF	98.18%	83.7%	1077

Company witness Miller also testified that the Company, like other utilities across the United States, has experienced a change in the historical dispatch order for each type of generating facility due to favorable economics resulting from the low pricing of natural gas, which includes the expansion of shale gas as described in Company witness Daji's testimony. Further, the addition of new CC units within DEP's portfolio in recent years has provided DEP with additional natural gas resources that feature state-of-the-art technology for increased efficiency, fuel flexibility, and significantly reduced emissions. These factors promote the use of natural gas and provide real benefits in both pricing and reduced emissions for customers. Gas-fired facilities provided 54% of the DEP fossil/hydro generation during the test period.

Based upon the evidence in the record, the Commission concludes that DEP managed its baseload plants prudently and efficiently so as to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's revised fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in 2008, and were in effect throughout the 12 months ending March 31, 2015. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses McGee, Daji, Miller, and Church.

Company witness McGee testified that DEP's fuel procurement strategies that mitigate volatility in supply costs are a key factor in DEP's ability to maintain lower fuel and fuel-related rates. Other key factors include DEP's diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; the combination of DEP's and Duke Energy Carolinas, LLC's (DEC's) respective skills in procuring, transporting, managing and blending fuels and procuring reagents; the increased and broader purchasing ability of the combined companies; and the joint dispatch of DEP's and DEC's generation resources.

Company witness Daji described DEP's fossil fuel procurement practices, set forth in Daji Exhibit 1. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, and conducting short-term and spot purchases to supplement term supply.

According to witness Daji, the Company's average delivered coal cost per ton decreased approximately 0.6%, from $89.28 per ton in the prior test period to $88.77 per ton in the test period. The Company's transportation costs decreased approximately 4.7%, from $30.78 per ton in the prior test period to $29.34 per ton in the test period. Witness Daji stated that coal markets continue to be in a state of flux due to a number of factors, including (1) recent U.S. Environmental Protection Agency regulations for power plants that result in utilities retiring or modifying plants, which reduces total domestic steam coal demand, and can result in some plants shifting coal sources to different basins; (2) softening demand in global markets for both steam and metallurgical coal; (3) low natural gas prices and increased volatility due to continued increases in gas supply combined with installation of new CC generation by utilities, especially in the Southeast, which also reduces overall coal demand; (4) increasingly stringent safety regulations for mining operations, which result in higher costs and lower productivity; and, (5) the deterioration of the financial health of coal suppliers due to reduced demand and market pricing in combination with increasing production costs.

Witness Daji stated that due to increasing competitiveness between natural gas and coal for low cost electricity, DEP's coal generation will fluctuate with prevailing market conditions. She further stated that the actual coal burn for the test period was 6.7 million tons, which is 24.0% lower than the 8.9 million tons originally anticipated in the currently billed rate. Although the projected coal burn reflected in the rate proposed for the billing period is 6.6 million tons, the Company's projected coal burn may be impacted by changes in natural gas prices, volatile power prices, and demand. DEP coal inventory levels were on target at a 40-day supply at the end of the test period. Future inventory levels are dependent on actual versus projected coal burns and actual coal deliveries based on performance of the railroads. She also testified that combining coal and transportation costs, DEP projects average delivered coal costs of approximately $76.81 per ton for the billing period. This represents a 13.5% decrease compared to the test period actual cost.

According to witness Daji, DEP continues to maintain a comprehensive coal procurement strategy that has proven successful over many years in limiting average annual coal price increases and maintaining average coal costs at or well below those seen in the marketplace. Aspects of this procurement strategy include having the appropriate mix of contract and spot purchases; staggering contract expirations, which thereby limit exposure to changes in market prices or coal burns; continuing to maintain the capability to burn a wide variety of coal types enabling coal sourcing efforts to promptly respond to changes in market conditions; and pursuing contract extension options that provide flexibility to extend terms within a particular price band. Witness Daji further testified that the Company expects to address any spot and long-term coal requirements throughout this year through competitively bid purchases, taking into account projected coal burns as well as coal inventory levels.

Witness Daji further testified that the Company's natural gas consumption is expected to continue to increase. The Company consumed approximately 137 billion cubic feet (Bcf) of natural gas in the test period, compared to approximately 121 Bcf in the prior test period. This increase in natural gas consumption was primarily the result of the full year of operations of DEP's Sutton CC that went into commercial service in late 2013. For the billing period, DEP's current forecasted natural gas consumption is approximately 129 Bcf.

Witness Daji also testified that the development of shale gas has created a fundamental shift in the nation's natural gas market. Given continued production increases, forward natural gas prices continue to remain at lower levels. The Company's average price of gas purchased for the test period was $6.03 per million British Thermal Units (MMBtu), compared to $6.18 per MMBtu during the prior test period.

G.S. 62-133.2(a1)(3) permits DEP to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Miller testified that the Company's fossil/hydro generation portfolio consists of 9,176 MW of generating capacity, 3,334 MW of which is coal-fired generation across three generating stations and a total of seven units. These units are equipped with emission control equipment, including selective catalytic reduction (SCR) equipment for removing nitrogen oxides (NOx), flue gas desulfurization (FGD or scrubber) equipment for removing sulfur dioxide (SO_2), and low NOx burners. This inventory of coal-fired assets with emission control equipment employed enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content – providing flexibility for DEP to procure the best cost options for coal supply.

Company witness Miller further testified that overall, the type and quantity of chemicals used to reduce emissions at the plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emissions reduction required. He stated that the Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. He also stated that the goal is to effectively comply with emissions regulations and provide the most efficient total-cost solution for operation of the unit.

Company witness Church testified as to DEP's nuclear fuel procurement practices, which include computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of spot and long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Church explained that for uranium concentrates as well as conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that throughout the industry, the typical initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, DEP relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis, using multi-year contracts.

G.S. 62-133.2(a1)(4), (5), (6), and (7) permit the recovery of the cost of non-capacity power purchases subject to economic dispatch or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Daji testified that DEP and DEC utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider the latest forecasted fuel prices, outages at the generating units based on planned maintenance and refueling schedules, contingency for forced outages based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases in order to determine the most economic and reliable means of serving their customers.

In its post-hearing brief, NCSEA states that it does not challenge any costs for which DEP seeks recovery in this proceeding, but requests that the Commission encourage DEP to continue its prudent natural gas hedging practices and to continue to explore diversifying its supply portfolio to include more clean energy solutions that do not consume fuel. Thus, the Commission notes that NCSEA does not oppose recovery of DEP's proposed fuel and fuel-related costs in this proceeding.

No party presented or elicited testimony contesting the Company's fuel and reagent procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the absence of any direct testimony to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the testimony of Company witnesses Daji and McGee.

Company witness Daji testified about the JDA, which is an agreement between DEP and DEC (the Companies) whereby DEC acts as the Joint Dispatcher for DEP's and DEC's power supply resources. She stated that the JDA has allowed DEP's and DEC's generation resources to be dispatched as a single system to meet the utilities' retail and firm wholesale customers' requirements at the lowest possible cost. As a result, the joint dispatch process allows the Companies to serve their retail and wholesale native load customers more efficiently and economically than they can on a stand-alone basis.

Witness Daji testified that the JDA provides a methodology for calculating the savings generated by the joint dispatch process and for equitably allocating the savings between the Companies. The joint dispatch savings automatically flow through to the Companies' retail customers through their fuel clauses. For native load wholesale customers, the joint dispatch savings are passed through as permitted by the applicable wholesale contracts. Under the joint dispatch process, the energy costs attributable to each utility's native load are the costs actually incurred by the utility for energy allocated to native load service, adjusted by the cost allocation payments calculated by the Joint Dispatcher, which are treated as purchases and sales between the Companies. As a result, the energy cost totals ultimately incurred by the Companies to serve their respective native loads will be equal to the stand-alone costs they would have incurred but for the joint dispatch arrangement, less each utility's share of the joint dispatch savings.

According to witness Daji, through May 2015, the combined merger savings from the JDA and the Companies' fuel procurement activities are $512 million. DEP's and DEC's customers are allocated their share of the combined savings based upon the resource ratios of the combined Companies. This resource ratio is 38.9% for DEP and 61.1% for DEC through May 2015.

Company witness McGee testified that merger fuel-related savings automatically flow through to DEP's retail customers through the fuel and fuel-related cost component of customers' rates. She explained that actual merger fuel-related savings during the test period are included in the EMF portion of the proposed fuel and fuel-related cost factors. In addition, the projected merger fuel-related savings related to the procurement of coal and reagents, lower transportation costs, lower gas capacity costs, and coal blending are reflected in the cost of fossil fuel in the projected component of the fuel and fuel-related cost factors. Projected joint dispatch savings, which result from using DEP's and DEC's combined systems' lowest available generation to meet total customer demand, are also reflected in the cost of fossil fuel as well as the projected cost purchases and sales that include the purchases and sales between the Companies.

Based on the evidence presented by DEP, and noting the absence of evidence presented to the contrary by any other party, the Commission finds and concludes that the Company's merger-related fuel savings for the test period are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness McGee.

According to the exhibits sponsored by Company witness McGee, the test period per book system sales were 57,715,306 MWh, and test period per book system generation and purchased power amounted to 66,335,921 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (McGee Exhibit 6):

Net Generation Type	MWh
Coal	15,011,404
Natural Gas, Oil and Biomass	19,535,270
Nuclear	25,942,058
Hydro – Conventional	596,433
Purchased Power – subject to economic dispatch or curtailment	3,034,255
Other Purchased Power	2,216,501
Total Net Generation	66,335,921

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 4.

No party took issue with the portions of witness McGee's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 57,715,306 MWh and system generation and purchased power of 66,335,921 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Repko and the affidavit of Public Staff witness Lucas.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and any unusual events. The Company proposed using a 94.3% capacity factor in this proceeding based on the operational history of the Company's nuclear units, and the number of planned outage days scheduled during the 2015-2016 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 88.3% for the period 2009-2013 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report. Public Staff witness Lucas did not dispute the Company's proposed use of a 94.3% capacity factor.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEP system, and the fact that the Public Staff did not dispute the Company's proposed capacity factor, the Commission concludes that the 94.3% nuclear capacity factor, and its associated generation of 29,323,747 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee.

On her Exhibit 4, Company witness McGee set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 37,993,413 MWh, comprised of Residential class sales of 16,103,240 MWh, Small General Service sales of 1,914,039 MWh, Medium General Service sales of 11,152,159 MWh, Large General Service sales 8,378,166 MWh, and Lighting class sales of 445,809 MWh.

Witness McGee used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on McGee Exhibit 2, Schedule 1, is 62,510,062 MWh. The projected level of generation and purchased power used was 69,978,628 MWh (calculated using the 94.3% capacity factor found reasonable and appropriate above), and was broken down by witness McGee as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	16,739,697
Gas Combustion Turbine and Combined Cycle	18,376,760
Nuclear	29,323,747
Hydro	607,739
Purchased Power	4,930,685
Total	69,978,628

As part of her Workpaper 7, Company witness McGee also presented an estimate of the projected billing period North Carolina retail Residential, Small General Service, Medium General Service, Large General Service, and Lighting MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	15,699,600
Small General Service	1,909,694
Medium General Service	0,538,645
Large General Service	8,826,039
Lighting	493,804
Total	37,467,782

These class totals were used in McGee Exhibit 2, Schedule 1, in calculating the total fuel and fuel-related cost factors by customer class.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and the absence of evidence presented to the contrary, the

Commission concludes that the projected North Carolina retail levels of sales set forth in the Company's exhibits (normalized for customer growth and weather), as well as the projected levels of generation and purchased power, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses McGee and Daji and the affidavit of Public Staff witness Lucas.

Company witness McGee recommended fuel and fuel-related prices and expenses, for purposes of determining projected system fuel expense, as follows:

A. The coal fuel price is $31.84/MWh.
B. The gas CT and CC fuel price is $34.39/MWh.
C. The appropriate system expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $57,129,387.
D. The total nuclear fuel price (including Joint Owners generation) is $6.86/MWh.
E. The total system purchased power cost (including the impact of JDA Savings Shared) is $196,182,466.
F. System fuel expense recovered through intersystem sales is $132,620,279.

These amounts are set forth on or derived from McGee Exhibit 2, Schedule 1. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company and the Public Staff.

In his affidavit, Public Staff witness Lucas stated that, based on his review, it appears that the projected fuel and reagent costs set forth in DEP's testimony, and the prospective components of the total fuel factor, have been calculated in accordance with the requirements of G.S. 62-133.2.

No other party presented evidence on the level of DEP's fuel and fuel-related prices and expenses.

Based upon the evidence in the record as to the appropriate fuel and fuel-related prices and expenses, the Commission concludes that the fuel and fuel-related prices recommended by Company witness McGee and accepted by the Public Staff for purposes of determining projected system fuel expense are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness McGee and the affidavit of Public Staff witness Lucas.

According to McGee Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $899,382,837. Public Staff witness Lucas did not take issue with her calculation.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $899,382,837 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-18

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee and the affidavits of Public Staff witnesses Lucas and Peedin.

Company witness McGee presented DEP's original fuel and fuel-related expense under-collection and prospective fuel and fuel-related cost factors. Company witness McGee's supplemental testimony sets forth the projected fuel and fuel-related costs, the amount of over/(under) collection for purposes of the EMF, the method for allocating the decrease in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and the EMFs along with revised exhibits and workpapers. Public Staff witness Peedin testified that the supplemental testimony of Company witness McGee supports corrections to the Company's original filing by adjusting under-recoveries related to (1) the capacity costs of several purchased power transactions that were calculated incorrectly, and (2) broker fees that were inadvertently omitted from the cost of natural gas delivered. The net effect of these corrections is to decrease the originally filed EMF increment riders. Public Staff witness Lucas recommended the approval of the prospective and EMF components and total fuel factors (excluding regulatory fee) set forth in Company witness McGee's supplemental testimony.

Public Staff witness Peedin testified that DEP's EMF increment riders for each customer class should be approved based on the following under-recoveries, broken down as follows:

Test Period

N.C. Retail Customer Class Customer Class	Over/ (Under)recovery
Residential	$(18,916,298)
Small General Service	(2,623,759)
Medium General Service	(17,127,474)
Large General Service	(28,320,778)
Lighting	(1,717,903)
Total	$(68,706,211)

As a result of these amounts, Public Staff witnesses Peedin and Lucas recommended approval of the following EMF increment billing factors, excluding the regulatory fee:

N.C. Retail Customer Class	EMF Increment (cents/kWh)
Residential	0.117
Small General Service	0.137
Medium General Service	0.154
Large General Service	0.338
Lighting	0.385

These factors are also set forth on Revised McGee Exhibit 1.

The Commission concludes that the EMF increment billing factors set forth in the affidavits of Public Staff witnesses Lucas and Peedin are reasonable and appropriate for use in this proceeding.

Company witness McGee calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. She stated that the decrease in fuel costs from the amounts approved in Docket No. E-2, Sub 1045, should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEP fuel cases approved by this Commission. No party opposed the use of this allocation method. Public Staff witness Lucas recommended the approval of the prospective and total fuel and fuel-related cost factors (excluding regulatory fee) set forth in Company witness McGee's testimony.

Based upon the testimony and exhibits in the record, the Commission concludes that DEP's projected fuel and fuel-related cost of $899,382,837 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that DEP's EMFs proposed in this proceeding, excluding the regulatory fee, and DEP's prospective fuel and fuel-related cost factors proposed in this proceeding for each of its rate classes, are appropriate. Additionally, the Commission concludes that DEP's decrease in fuel and fuel-related costs from the amounts approved in Docket No. E-2, Sub 1045 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEP's past fuel cases.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence for this finding of fact is contained in the testimony of Company witness McGee and in the affidavits of Public Staff witnesses Peedin and Lucas.

The Commission has carefully reviewed the evidence and record in this proceeding. The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF, are not opposed by any party. Accordingly, the overall fuel and fuel-related cost calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 2.567¢/kWh for the Residential class, 2.570¢/kWh for the Small General Service class, 2.587¢/kWh for the Medium General Service class, 2.627¢/kWh for the Large General Service class, and 2.511¢/kWh for the Lighting class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 2.450¢/kWh, 2.433¢/kWh, 2.433¢/kWh, 2.289¢/kWh, and 2.126¢/kWh, and EMF increments of 0.117¢, 0.137¢, 0.154¢, 0.338¢, and 0.385¢/kWh, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively, all excluding the regulatory fee. The billing factors, both excluding and including the regulatory fee, are shown in Appendix A to this Order.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after December 1, 2015, DEP shall adjust the restated base fuel and fuel-related cost factors in its North Carolina retail rates, as approved in Docket No. E-2, Sub 1045, amounting to 3.013¢/kWh for the Residential class, 3.001¢/kWh for the Small General Service class, 2.921¢/kWh for the Medium General Service class, 2.958¢/kWh for the Large General Service class, and 3.655¢/kWh for the Lighting class (all excluding the regulatory fee), by amounts equal to (0.563)¢/kWh, (0.568)¢/kWh, (0.488)¢/kWh, (0.669)¢/kWh and (1.529)¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments of 0.117¢/kWh for the Residential class, 0.137¢/kWh for the Small General Service class, 0.154¢/kWh for the Medium General Service class, 0.338¢/kWh for the Large General Service class, and 0.385¢/kWh for the Lighting class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through November 30, 2016;

2. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments no later than 10 days from the date of this Order; and

3. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket No. E-2, Subs 1023, 1069, 1070, 1071, and 1088, and the Company shall file the proposed customer notice for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of November, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

Appendix A

EXCLUDING REGULATORY FEE

	A	B	C	D	E
Class	**Restated Base Fuel Rate**	**Decrement to Restated Base Fuel Rate**	**Prospective Rate (Columns A + B)**	**EMF Increment**	**Billed Rate (Cols. C + D)**
Residential	3.013	(0.563)	2.450	0.117	2.567
Small General Service	3.001	(0.568)	2.433	0.137	2.570
Medium General Service	2.921	(0.488)	2.433	0.154	2.587
Large General Service	2.958	(0.669)	2.289	0.338	2.627
Lighting	3.655	(1.529)	2.126	0.385	2.511

INCLUDING REGULATORY FEE

	A	B	C	D	E
Class	**Restated Base Fuel Rate**	**Decrement to Restated Base Fuel Rate**	**Prospective Rate (Columns A + B)**	**EMF Increment**	**Billed Rate (Cols. C + D)**
Residential	3.017	(0.564)	2.453	0.117	2.570
Small General Service	3.005	(0.569)	2.436	0.137	2.573
Medium General Service	2.925	(0.489)	2.436	0.154	2.590
Large General Service	2.962	(0.670)	2.292	0.339	2.631
Lighting	3.660	(1.531)	2.129	0.386	2.515

DOCKET NO. E-22, SUB 522

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Battleboro Farm, LLC, and Cypress Creek Renewables, LLC, Complainants v. Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, Respondent	)	ORDER ESTABLISHING DATE OF LEGALLY ENFORCEABLE OBLIGATION

BY THE COMMISSION: On May 20, 2015, Battleboro Farm, LLC (Battleboro), and Cypress Creek Renewables, LLC (collectively, Complainants),[1] filed a verified Complaint and Request for Declaratory Ruling (Complaint) in the above-captioned docket against Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP).

In summary, Complainants allege that Battleboro is developing a 5-MW solar photovoltaic renewable energy facility to be located in DNCP's service territory and that Battleboro is entitled to sell power to DNCP under terms established pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA). In addition, Complainants allege that Battleboro's facility is a qualifying facility (QF) under PURPA, that it has obtained a certificate of public convenience and necessity (CPCN) from the Commission authorizing construction of its facility, and that it has committed to sell its electric output to DNCP. Further, Complainants allege that Battleboro has the right under PURPA to enter into a long-term power purchase agreement (PPA) for the sale of the facility's capacity and energy to DNCP at the avoided cost rates established by the Commission's February 21, 2014 Order issued in Docket No. E-100, Sub 136 (Sub 136 Order). Moreover, Complainants maintain that Battleboro has taken the steps required to create a legally enforceable obligation (LEO) to obligate DNCP to purchase the facility's output. Complainants contend that the date of the LEO is April 22, 2014, based primarily on the Commission's Order issued that date in Docket No. SP-3284, Sub 0 granting Battleboro a CPCN and stating that Battleboro plans to sell its electricity to DNCP. Complainants further aver that there is a dispute between Complainants and DNCP as to the date on which the LEO for Battleboro was established and that DNCP has failed to provide Complainants with proposed avoided cost rates that are consistent with the rates approved by the Commission in the Sub 136 Order.

The relief requested by Complainants is that the Commission treat their Complaint as a request for declaratory judgment pursuant to G.S. 1-253, declare that Battleboro has a LEO as of April 22, 2014, for the sale of its capacity and energy to DNCP, order DNCP to provide proposed avoided cost

[1] Cypress Creek Renewables, LLC, is a developer of solar photovoltaic generating facilities across the United States, including various locations in North Carolina, and is the sole member of Battleboro.

rates and a draft PPA to Battleboro that is consistent with the rates approved in the Sub 136 Order, and schedule this matter for an expedited hearing.

On May 22, 2015, the Commission issued an Order Serving Complaint and Requiring Response. The Order directed the Chief Clerk to serve the Complaint on DNCP and directed DNCP to either satisfy the demands of the Complainants and so advise the Commission, or file a response to the Complaint on or before June 17, 2015.

On June 17, 2015, DNCP filed a Response to Complaint. In summary, DNCP discusses the Commission's two-prong LEO test requiring that the QF (1) have a CPCN and (2) have made a commitment to sell its electric output to a utility pursuant to a PPA. DNCP admits that Battleboro became a QF on April 9, 2014, by filing Form 556 with the Federal Energy Regulatory Commission (FERC) for self-certification as a QF on that date. In addition, DNCP admits that Battleboro obtained a CPCN from the Commission on April 22, 2014. However, DNCP denies that the issuance of the CPCN satisfied the second prong of the Commission's LEO test. In particular, it asserts that the statement in the Order issuing the CPCN that Battleboro "plans to sell the electricity to Dominion North Carolina Power" was not a written commitment by Battleboro to sell its output to DNCP. Rather, DNCP maintains that Battleboro did not make the required written commitment until March 4, 2015. Therefore, DNCP contends that Battleboro is not entitled to receive the rates approved in the Sub 136 Order. Instead, it asserts that Battleboro is entitled to receive the rates to be established by the Commission in the pending avoided cost docket, Docket No. E-100, Sub 140.

On July 22, 2015, the Commission issued an Order Allowing Filing of Briefs and Proposed Orders allowing Complainants and DNCP the opportunity to file briefs and/or proposed orders supporting their positions by August 10, 2015.

On August 10, 2015, Complainants filed a brief and DNCP filed a proposed order.

PARTIES' POSITIONS

<u>Complainants' Position</u>

Based on the Commission's two-prong LEO test, Complainants maintain that the date on which Battleboro was issued a CPCN, April 22, 2014, is the date of Battleboro's LEO. In support of their position, Complainants describe the course of dealings between Battleboro and DNCP and submit that this course of dealings, along with other factors, establish that Battleboro made a commitment to sell its electricity to DNCP no later than April 22, 2014. In particular, Complainants state that Battleboro's interconnection application to DNCP, submitted on May 21, 2013, pursuant to the North Carolina Interconnection Procedures for State-Jurisdictional Generator Interconnections (NCIP), included a statement that Battleboro intended to supply power to DNCP. In addition, Complainants note that the NCIP was approved by the Commission. Complainants state that Section 1.1.1 of the NCIP provides that "[t]hese procedures apply to Generating Facilities that are interconnecting to Utility Systems in North Carolina where the Interconnection Customer is not selling the output of its Generating Facility to an entity other than the Utility to which it is interconnecting." Complainants also cite a question on page 3 of the NCIP interconnection application regarding use of the electricity generated by the facility and state that Battleboro answered the question by stating that it would supply power to DNCP[1] In addition, Complainants state that on April 3, 2014, Battleboro paid DNCP interconnection costs of $131,654. Therefore, Complainants submit that by the terms of the NCIP a state-jurisdictional interconnection request made to DNCP and the generator's payment of a substantial interconnection fee signify the generator's intention to sell its power to DNCP. Thus, Battleboro maintains that its LEO was established on April 22, 2014, when its CPCN was issued, having satisfied both prongs of the Commission's LEO test.

In addition, Complainants maintain that Battleboro stated in its CPCN application, and the Commission included in its Order Requiring Publication of Notice, that the owner of the facility "plans to sell the electricity to Dominion North Carolina Power." Further, the Commission included in the order granting Battleboro's CPCN the statement that "the Applicant plans to sell the electricity to Dominion North Carolina Power." Complainants submit that these statements constitute a sufficient commitment by Battleboro to DNCP to sell its power to DNCP.

Moreover, Complainants submit that the Commission has not established a bright line test for determining the exact date of a LEO. Acknowledging that the Commission's previous arbitration decisions are not precedential, Complainants nonetheless submit that there is guidance in those decisions in that the Commission has engaged in a fact-specific inquiry on the issue of whether the owner of the facility has committed to sell its output to the utility, rather than attempting to articulate a single, specific action that must be taken by the owner to satisfy that prong of the LEO test. Thus, Complainants contend that the Commission should conclude, based on the particular facts of this case, that Battleboro had taken all necessary actions to commit to sell its electricity to DNCP by the date on which Battleboro's CPCN was issued.

Complainants also contend that Battleboro's FERC Form 556, a copy of which was served on DNCP, constituted a commitment to sell electricity to DNCP because the form identified DNCP as the utility that would purchase the facility's output.

In addition, Complainants submit that DNCP identified Battleboro in a November 25, 2014 filing at FERC as a facility that might be affected by DNCP's request for exemption from certain requirements under PURPA Section 210(m). Complainants maintain that this constitutes evidence that DNCP knew that Battleboro had committed to sell its output to DNCP.

Finally, Complainants take issue with what they perceive to be DNCP's position that a commitment to sell to DNCP requires that the generator request that a PPA be sent to it.[2]

DNCP's Position

DNCP disagrees with Complainants' position that the second prong of the Commission's LEO test, requiring a commitment to sell the output of the facility to the utility, is met by submitting a request

[1] Complainants attached a completed copy of the interconnection request form as Exhibit No. 1 to their Brief.

[2] A similar factual issue regarding the establishment of a LEO is presented in Fresh Air Energy XXV, LLC, et al. (FAE) v. DNCP, Docket No. E-22, Sub 521. In that docket, DNCP's Reply Brief clarifies that a request for a draft PPA or a PPA contract form is not required to meet the second prong of the LEO test. Rather, it is the QF's commitment to sell its electricity to the utility that satisfies the second prong. DNCP states in Sub 521 that the electronic mail sent by FAE to DNCP expressed the commitment by making a request for DNCP to send FAE the PPA contract form.

for interconnection, by statements in the FERC Form 556, by filing a CPCN application and providing DNCP with a copy, or by the Commission's statement in its order issuing the CPCN that Battleboro "plans to sell the electricity to Dominion North Carolina Power." DNCP contends that these events, individually or in the aggregate, did not constitute a commitment by Battleboro to sell its output to DNCP. In addition, with regard to the interconnection request, DNCP cites Article 1.3 of the Commission-approved Interconnection Agreement form, which states:

> This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power or Renewable Energy Certificates (RECs). The purchase or delivery of power, RECs that might result from the operation of the Generating Facility, and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable Utility.

DNCP acknowledges that from the date of Battleboro's interconnection request, May 21, 2013, until the date the interconnection agreement was executed, August 15, 2014, Battleboro and representatives of DNCP's interconnection department engaged in oral and written communications related exclusively to the interconnection of the facility to DNCP's distribution system. However, DNCP maintains that at no time prior to March 4, 2015, did any DNCP personnel receive any communication from Battleboro committing to sell the output of the facility to DNCP. Further, DNCP denies Battleboro's allegation that "Battleboro had extensive communications with DNCP from May 2013 through April 2014 regarding its plans to build the facility" to the extent that Complainants are implying that those communications related to a PPA for the facility or otherwise constituted a commitment by Battleboro to DNCP to sell the output of the facility to DNCP.

With regard to its position that March 4, 2015, is the date on which Battleboro made its commitment, DNCP states that a Battleboro representative sent an electronic mail on that date to Donna Lynch in DNCP's interconnection department asking about the existence of a PPA for the facility. By electronic mail dated March 5, 2015, Lynch informed Battleboro that her department worked only with interconnection agreements and that for a PPA Battleboro would need to contact DNCP's Power Contracts group. DNCP further notes that on or about March 31, 2015, a Battleboro representative contacted John Hampson in the Power Contracts Department, and Hampson informed Battleboro that it did not qualify for a Schedule 19-FP contract because it did not seek a PPA prior to March 3, 2015. DNCP further notes Complainants' allegation that between May 2013 and April 2014 Battleboro was "never informed … that communication regarding its intent to sell had to [be] directed to any specific person or department within DNCP." In response, DNCP states that this issue is not relevant to the present docket because at no time prior to March 4, 2015, did Complainants make any commitment to sell the output of Battleboro's facility to any person or department within DNCP.

DNCP acknowledges that on or about April 10, 2014, its interconnection department received a copy of the FERC Form 556 that Battleboro filed with FERC. DNCP also acknowledges that the Form 556 identified DNCP as the utility purchasing the output of the facility. DNCP denies, however, that Battleboro's statement to FERC in its Form 556 self-certification regarding planned sales to DNCP constituted a commitment by Battleboro to DNCP to sell the output of the facility to DNCP.

Finally, DNCP denies Complainants' allegation that DNCP's identification of Battleboro in its PURPA Section 210(m) filing at FERC "evidenced DNCP's knowledge of Battleboro's commitment to sell its generation to DNCP." DNCP states that FERC's Section 210(m) regulations require utilities to provide notice to each "potentially affected qualifying facility."[1] DNCP notes that FERC has stated specifically that facilities that are not yet QFs should be included as "potentially affected" QFs.[2] DNCP states, therefore, that its inclusion of Battleboro in the Section 210(m) filing signified nothing more than DNCP's compliance with FERC's requirements. In addition, DNCP notes that its unilateral act of including Battleboro in its Section 210(m) filing cannot be interpreted as a written commitment from Battleboro to sell its output to DNCP.

DISCUSSION

Complainants request a declaratory judgment from the Commission establishing the LEO date for Battleboro's solar facility. FERC has left it to the state commissions to decide how and when a LEO is created. See New PURPA Section 210(m) Regulations, FERC Order No. 688-A, 119 FERC ¶ 61,305, at ¶¶ 136, 139 (2007).

The parties agree that Battleboro has established a LEO; however, they disagree on the date of the LEO. As discussed by the parties, the Commission has adopted a two-prong test for the establishment of a LEO. See Sub 136 Order, at 35. In order to establish a LEO, the owner of a generating facility must: (1) have made a commitment to sell the facility's output to a utility pursuant to PURPA, and (2) have received a CPCN for the construction of the facility. Complainants' petition and DNCP's response present the Commission with the issue of whether statements that a facility "plans to sell the electricity to Dominion North Carolina Power" included in the CPCN application and CPCN Orders, or similar statements in the facility owner's interconnection application and FERC Form 556 constitute a commitment by the owner to sell its output to DNCP.

In the Commission's analysis of this issue, the Commission is guided by two main factors: (1) the purpose of a LEO, and (2) the guidelines for establishing a LEO that have previously been approved by the Commission and relied upon by the parties.

Purpose of the LEO

The concept of a LEO was created by FERC in its rules implementing PURPA. Section 292.304(d) of the rules provides:

> (d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:
>
> (1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

[1] 18 C.F.R. § 292.310(c) (2015).

[2] Commonwealth Edison Co., 135 FERC ¶ 61,005 at ¶ 41 (2011).

> (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (i) The avoided costs calculated at the time of delivery; or
> (ii) The avoided costs calculated at the time the obligation is incurred.

18 C.F.R. § 292.304(d).

The purpose of the LEO is to establish a date certain for determining the applicable avoided cost rates to be used in the PPA between the generator and the utility. For example, smaller QFs, such as Battleboro, which qualify for the standard avoided cost rates and contract approved biennially by the Commission, would be entitled to receive the rates in effect on the date the LEO was established. Larger QFs, which are not eligible for the standard avoided cost rates and contract, but must negotiate rates, are, nonetheless, entitled to be paid at the avoided cost rates calculated as of the date of the LEO. In this way, the LEO protects the generator from delays in PPA negotiations. In turn, the LEO also protects the utility from having to expend time unnecessarily engaging in negotiations to sign a PPA when a generator might never obtain a CPCN to build its proposed facility or make a commitment to sell its electricity to the utility.

Existing Guidelines for Establishing a LEO

The Complainants cite and discuss the Commission's Orders on Arbitration in EPCOR v. Progress Energy Carolinas, Inc., Docket No. E-2, Sub 966 (Jan. 26, 2011) (EPCOR), and Economic Power & Steam Generation, LLC v. Virginia Electric & Power Company, Docket No. SP-467, Sub 1 (June 18, 2010) (EP&S). As Complainants acknowledge, however, the Commission stated both in the EPCOR and EP&S Orders that its decisions were being made in arbitration proceedings and were not precedent for future Commission decisions. See EPCOR, Order on Arbitration, at 8; EP&S, Final Order on Arbitration, at 7.

Rather than attempting to apply prior decisions based on different facts, the Commission concludes that it is more helpful to focus on DNCP's Schedule 19-FP, the plain meaning of the schedule's terms, and the parties' reasonable expectations.

Actions Required for a LEO Commitment

Schedule 19-FP, as approved by the Commission in Docket No. E-100, Sub 136, provides in Section I, as follows:

> [T]his schedule is available to any Qualifying Facility (otherwise eligible pursuant to the terms hereof) that by November 1, 2014 or the date upon which proposed rates are filed in Docket No. E-100 Sub 140, if later than November 1, 2014, (a) has obtained a certificate of public convenience and necessity for its facility from the Commission or filed a report of proposed construction with the Commission pursuant to Commission Rule [R]8-65, and (b) has indicated to the Company in writing that it is committed to selling the output of the facility to the Company pursuant to the terms of this schedule.

Proposed new avoided cost rates were filed by DNCP in Docket No. E-100, Sub 140 on March 2, 2015.

The Commission is not aware of any Commission precedent or court decisions interpreting the Schedule 19-FP phrase "committed to selling the output of the facility to the Company," and the parties have cited no such precedent. Thus, the Commission's first task is to apply the statutory interpretation principle that the words of a statute, regulation, or in this instance DNCP's tariff, should be given their plain meaning. See Lenox, Inc. v. Tolson, 353 N.C. 659, 664, 548 S.E.2d 513, 518 (2001). The operative word of the phrase "committed to selling the output of the facility to the Company," is "committed." The word "commit" is defined as "to pledge (oneself) to a position on some issue" and "to bind or obligate, as by a pledge." American Heritage Dictionary, New College Edition (1978).

Complainants contend that they made a commitment to sell the output of Battleboro's facility to DNCP on four occasions: (1) on May 21, 2013, when Battleboro filed an application to interconnect with DNCP, (2) on January 7, 2014, when Battleboro filed an application for a CPCN that included the statement that it "plans to sell the electricity to Dominion North Carolina Power", (3) on April 9, 2014, when Battleboro filed its FERC Form 556 that identified DNCP as the utility that would purchase the facility's output, and (4) on April 22, 2014, when the Commission issued an order granting the CPCN that contained the statement that Battleboro "plans to sell the electricity to Dominion North Carolina Power." In addition, Battleboro submits that DNCP's inclusion of Battleboro in a November 25, 2014 filing at FERC as a facility that might be affected by DNCP's request for exemption from certain requirements under PURPA Section 210(m) constitutes evidence that DNCP knew that Battleboro had committed to sell its output to DNCP.

The Commission is not persuaded that an applicant's interconnection application constitutes a commitment to sell its power to the utility. The main purpose of an interconnection application is to provide the utility with the information necessary to assess the feasibility and effects of having the generator deliver its electricity to the utility's distribution system at a particular location. In addition, although an interconnection request might be deemed some indication of intent or likelihood that the generator might sell its electricity to the utility, it is not a direct statement or pledge that the generator will, in fact, enter into a PPA to sell its power to the utility.

Likewise, the Commission is not persuaded that the statement of a CPCN applicant that it "plans to sell the electricity to Dominion North Carolina Power," either in the CPCN application or as repeated in the Commission's Order Requiring Publication of Notice and CPCN Order, constitutes a commitment to sell the facility's electricity to DNCP. Commission Rule R8-64(b)(3)(v) requires that a generator's CPCN application include, among other information, "the applicant's general plan for sale of the electricity to be generated, including the utility to which the utility plans to sell the electricity." Rule R8-64(c)(1) further requires the applicant to mail a copy of the application and notice "to the electric utility to which the applicant plans to sell the electricity to be generated."

A statement regarding the "general plan" for the sale of the applicant's electricity to a utility, however, is not a commitment to sell to that utility. The main purpose for including this statement in the CPCN application and requiring notice is to inform the public and the utility of the applicant's general plan for the sale of the electricity. Moreover, the statement that the applicant "plans to sell the electricity" to a particular utility is a standard phrase that has been included in virtually all of the Commission's CPCN orders. If the Commission had intended the inclusion of this phrase to serve as the applicant's commitment to sell to the utility, then the LEO test would be simply the issuance of a CPCN Order that contains this phrase. Instead, the Commission included a second prong in the test requiring an express commitment by the generator to sell its electricity to the utility.

Further, the Commission is not persuaded that the "commitment to sell" prong of the LEO test can be met by general statements regarding the sale of the facility's output to the utility in a qualifying facility's FERC Form 556. Similar to statements in the CPCN application, statements of intent in Form 556 with regard to sales from the facility are not equivalent to a commitment to sell and, therefore, do not meet the LEO requirement.

Finally, with respect to DNCP's PURPA Section 210(m) filing, the Commission is not persuaded that DNCP's inclusion of Battleboro on the list of potentially affected facilities satisfies the commitment to sell prong of the LEO test. That filing by DNCP was not a commitment from the owner of the facility to the utility to sell the facility's output to the utility or material evidence of the existence of such a commitment. Rather, it was merely DNCP's compliance with FERC's filing requirements.

Therefore, Complainants cannot rely upon notice to DNCP in the interconnection, CPCN application, or FERC qualifying facility processes as the communication of Battleboro's commitment to sell the output of its facility required by the Commission to establish a LEO. Rather, that commitment must be separately and clearly communicated to the utility in writing, as stated in DNCP's Schedule 19-FP.

In the present case, the Commission is persuaded, based on the purpose of a LEO, the plain meaning of DNCP's Schedule 19-FP, and Complainants' reasonable expectations, that Battleboro's first clear written commitment to sell its electricity to DNCP was made on March 4, 2015. As stipulated by DNCP, that is the date on which Battleboro sent an electronic mail to Donna Lynch in DNCP's interconnection department asking about the existence of a PPA for Battleboro's facility. There has been no showing that prior to March 4, 2015, there was a written communication from Battleboro to DNCP in which Battleboro made a commitment to sell its output to DNCP.

CONCLUSION

Based on the foregoing and the record in this proceeding, the Commission concludes that Battleboro's interconnection application, statements in the CPCN application and Orders that Battleboro "plans to sell the electricity to Dominion North Carolina Power," Battleboro's FERC Form 556, and DNCP's PURPA Section 210(m) filing, individually or collectively, did not constitute a commitment by Battleboro to sell the electric output of its facility to DNCP. In addition, the Commission concludes that Battleboro first met the "commitment to sell" prong of the LEO test on March 4, 2015. As a result, the Commission concludes that March 4, 2015, was the first date on which Battleboro (1) had obtained a CPCN for the construction of its facility, and (2) had made a commitment to sell its output to DNCP.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _22nd_ day of September, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner Susan W. Rabon did not participate in the decision.

DOCKET NO. E-7, SUB 1026

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas,	)	
LLC, for Adjustment of Rates and Charges	)	ORDER APPROVING PILOT
Applicable to Electric Utility Service in	)	PEAK TIME CREDIT PROGRAM
North Carolina	)	

BY THE COMMISSION: On September 24, 2013, the Commission issued an Order Granting General Rate Increase (Rate Order), in the above-captioned docket. In Ordering Paragraph No. 13 of the Rate Order, the Commission required Duke Energy Carolinas, LLC (DEC), to file within 15 months of the Rate Order a proposed pilot peak time rebate or critical peak pricing rate structure.

On November 7, 2014, DEC filed a request for Commission approval of its pilot Peak Time Credit Program (PTC Pilot). In addition, DEC attached its proposed Rider PTC as Exhibit A to its request.

On November 26, 2014, the Commission issued an Order Requesting Comments on Proposed Peak Time Credit Program seeking comments from interested parties on this matter. No party filed comments.

In its request, DEC states that it will offer the PTC Pilot for one summer season (June through September 2015). Participation will be limited to 600 customers, with 100 each from rate schedules RS, RE, SGS, RST, RET, and SGST. Participants will be required, prior to participation in the pilot, to have DEC install an advanced meter that is capable of providing interval meter data. Approximately 300,000 advanced meters have already been installed across DEC's North Carolina and South Carolina service area for customers served under one of its time-of-use rate schedules. Participants will have access to a web portal to see their hourly energy consumption, which will be available to participants on the next day.

DEC proposes to offer a bill credit of $0.34 for each kilowatt-hour (kWh) reduced below the participant’s baseline during a “critical peak event” (CPE). The calculation of the credit is based on DEC’s current Power Manager demand-side management program and is designed to incent customers to reduce their loads during the CPE. DEC will determine the number of kWh reduced for each CPE by using a comparison of the participant’s baseline usage to the participant’s actual kWh consumption during the CPE hours.

DEC states that the PTC Pilot will allow participating customers the opportunity to manage their energy usage during CPEs and is designed to study participant response during these events. Participants will receive an email one day ahead of a CPE to allow them sufficient opportunity to plan to reduce their usage. They will be required to reply to the email notification in the affirmative in order to qualify for the credit during the CPE. DEC intends to call multiple CPEs during the pilot, with an emphasis on hot summer days, to gauge participant response.

To determine the participant's baseline consumption, DEC will compare the participant's energy consumption during the CPE to the participant's consumption in the same hours during a 10-day period immediately preceding the event, excluding holidays and weekends. DEC will seek to use days in the baseline period having similar weather conditions to that of the CPE. If no similar weather days exist in the 10-day period, DEC will determine if the customer is weather-sensitive. If so, then DEC will make an account-specific weather adjustment to the participant's baseline. If the customer is not weather-sensitive, DEC will use the average consumption over the same 10-day period to establish the baseline.

DEC proposes to file a report with the Commission on the results of the PTC Pilot along with DEC's other TOU pilots approved by the Rate Order.

The Public Staff presented this matter at the Commission's Regular Staff Conference on April 20, 2015. The Public Staff stated that it had evaluated the calculation of the bill credits and DEC's proposed calculation of customers' baselines and reduced loads. The Public Staff stated that it believes these calculations represent a reasonable attempt to evaluate what the participant's load would have been in the absence of the PTC Pilot. To address the possible increase in load above the baseline for any hour during the critical peak event, DEC indicated that it will simply assign a zero value to any hour in which the participant increases load above the baseline. In other words, the participant will get no credit for that hour, nor will it be penalized for usage above the baseline.

Based upon its review, the Public Staff stated that DEC's proposal is reasonable and consistent with the requirement found in Ordering Paragraph No. 13 of the Rate Order. The Public Staff recommended that the Commission approve the proposed PTC Pilot and proposed Rider PTC. In addition, the Public Staff recommended that the Commission require DEC to address the following matters in its report on the results of the PTC Pilot: (1) the method of calculating load reductions, increases, and baselines for a representative sample of participants; (2) the weather conditions on critical peak event days, as well as the days used in the baseline calculations; (3) any instances in which participants failed to acknowledge receipt of the email CPE notifications; and (4) any disputes over the determination of the bill credits, including the calculations provided to any participant that disputed the amount of its credit. The Public Staff stated that DEC does not object to the Public Staff's recommendations.

Based on the foregoing, the Commission is of the opinion that DEC's request for approval of its proposed pilot Peak Time Credit Program and proposed Rider PTC is appropriate and should be approved. The Commission also concludes that the Public Staff's recommendations concerning DEC's report on the results of the PTC Pilot are reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC's pilot Peak Time Credit Program and Rider PTC are hereby approved.

2. That DEC shall file its report on the pilot Peak Time Credit Program and other TOU pilots implemented pursuant to the Rate Order as expeditiously as possible upon conclusion of the pilots.

3. That DEC should incorporate the reporting items recommended by the Public Staff in its report on the pilot Peak Time Credit Program.

ISSUED BY ORDER OF THE COMMISSION.
This the _20th_ of April, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioners Susan W. Rabon and ToNola D. Brown-Bland did not participate in this decision.

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DEC. 31, 2015

ONE-HUNDRED FIFTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume II

ISSUED FROM
JANUARY 1, 2015 THROUGH DECEMBER 31, 2015

ONE-HUNDRED FIFTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2015, through December 31, 2015

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

Don M. Bailey, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

North Carolina Utilities Commission
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The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

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DOCKET NO. E-22, SUB 464

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric and Power Company d/b/a Dominion North Carolina Power for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	)	ORDER APPROVING REVISED COST RECOVERY AND INCENTIVE MECHANISM AND GRANTING WAIVER

BY THE COMMMISSION: On October 14, 2011, in Docket No. E-22, Sub 464, the Commission issued an Order Approving Agreement and Stipulation of Settlement, Approving DSM/EE Rider, and Requiring Compliance Filing, which included Commission approval of the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Mechanism) agreed to between Virginia Electric & Power Company, d/b/a Dominion North Carolina Power (DNCP or the Company), and the Public Staff – North Carolina Utilities Commission (Public Staff).[1] Such Order provided that there would be a formal review of the Mechanism not later than October 1, 2014. In addition, the Commission required that such formal review specifically address whether the incentives in the Commission-approved Mechanism are producing significant demand-side management (DSM) and energy efficiency (EE) results, whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate, and any other relevant issues that may arise.

On September 29, 2014, DNCP filed a letter with the Commission regarding the upcoming Mechanism review. In its letter, the Company stated that the Mechanism has worked well in terms of functionality and transparency, and that any initial differences of opinion between the Public Staff and the Company as to its provisions have been resolved without significant controversy. Therefore, the Company suggested that only minor modifications to the Mechanism may be beneficial at this time. As such, DNCP recommended a streamlined review schedule allowing interested parties to file comments recommending any changes to the Mechanism. The Company stated that the Public Staff supported this recommendation.

On October 3, 2014, the Commission issued a procedural Order adopting a schedule for DNCP, the Public Staff, and all interested parties to file recommendations for changes to the Mechanism. Additionally, the Commission ordered that DNCP and the Public Staff address whether the incentives in DNCP's Mechanism are producing significant DSM and EE results, and whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate.

On January 15, 2015, and February 12, 2015, DNCP and the Public Staff jointly requested extensions of time to delay the filing of comments in order to continue discussions regarding what

[1] No parties other than the Public Staff participated in developing the Mechanism or have actively participated in the Company's annual DSM/EE cost recovery proceedings during 2011-2014 (Subs 473, 486, 494, and 513, respectively).

changes to the Mechanism may be appropriate. These Motions were granted by Orders issued January 16, 2015, and February 13, 2015, respectively.

On February 27, 2015, DNCP (in the form of a letter) and the Public Staff each filed comments in this proceeding supporting a proposed updated Mechanism, which was filed as Exhibit 1 to the Public Staff's comments (Mechanism Proposal).

No other parties intervened or filed comments in this proceeding.

DISCUSSION OF QUESTIONS POSED BY COMMISSION

In its comments, the Company explained that DNCP deploys DSM/EE programs on a system-wide basis, and the incentives provided in the Mechanism have supported DNCP's efforts to bring new programs to North Carolina for the benefit of its North Carolina customers. Further, the Company maintained that the Mechanism is generally working well as a component of its broader system-wide DSM/EE deployment strategy and that since the Mechanism was first approved in 2011 the Company has obtained approval to deploy three phases of DSM/EE Programs consisting of 13 EE programs and one DSM program. In addition, DNCP noted that the Company and the Public Staff have obtained Commission approval of two addenda to the Mechanism that have further promoted DSM/EE program deployment by facilitating full recovery of the Company's costs to deploy both system-wide and North Carolina-only DSM/EE programs. The Company also contended that the Mechanism is producing increasingly meaningful DSM and EE results for the State, as DNCP continues to build its DSM/EE program portfolio and expand program offerings in North Carolina.

The Public Staff, in its comments filed on February 27, 2015, first addressed the Commission question of whether the incentives in the Mechanism are producing significant DSM and EE results. Based on a number of factors, the Public Staff stated that it does not view DNCP's DSM and EE results as significant at this time, but that it was not apparent this was due to inadequate incentives. The Public Staff observed that DNCP's DSM and EE programs had produced system-wide retail EE savings in calendar year 2013 of 274,369 MWh, or 0.35% of system-wide retail sales for calendar year 2013. The Public Staff noted several factors that could potentially impact DNCP's achieved EE savings, including maturity of DNCP's DSM/EE programs relative to other utilities; the potential for DNCP's large industrial customers to "opt out" of EE programs, thus reducing achievable savings[1]; differences in retail electric rates and avoided costs between utilities affecting the cost-effectiveness of EE adoption; macroeconomic factors affecting DSM/EE adoption in recent years; and less tangible factors such as state environmental mandates and regulatory policy across jurisdictions that affect a utility's DSM/EE deployment. The Public Staff specifically highlighted the fact that Virginia Electric & Power Company's (VEPCO's) North Carolina service territory only constitutes approximately 5% of VEPCO's system with 95% being in Virginia, such that DNCP's DSM/EE activities are strongly influenced by policy and regulatory decisions in Virginia.

[1] The Public Staff noted that Nucor Steel-Herford, a division of Nucor Corporation, (Nucor) alone accounts for approximately 20% of DNCP's retail sales. Nucor, along with other large commercial and industrial customers, has opted out of the DSM/EE rider. Thus it is likely that the "opt out" provision has reduced EE savings to a greater degree for DNCP than most other utilities.

The Public Staff contended that it would be extremely difficult to exactly determine the extent to which each of these factors affects DNCP's achievement of DSM/EE savings and whether there is any correlation between a higher utility incentive and greater energy savings. Further, the Public Staff noted that when the Mechanism was approved by the Commission in 2011 the Mechanism established a program performance incentive (PPI) as the appropriate utility bonus incentive. ThePPI defines the type and amount of DNCP's bonus incentive as a percentage of net DSM or EE savings, which incentivizes DNCP to maximize its savings.

Moreover, the Public Staff commented that the PPI is similar to the type and amount of incentive that Duke Energy Progress, Inc.(DEP), employed until recently (i.e., 8% of the dollar savings are awarded to the utility as a program performance incentive on DSM programs and 13% on EE programs). The Public Staff noted, however, that DNCP has achieved a smaller amount of EE savings as a percentage of total retail sales. Thus, the Public Staff concluded that the Mechanism, including the level of PPI, is not the predominant factor in determining whether DNCP is producing significant DSM and EE results.

Additionally, the Public Staff contended that while Virginia regulatory policy may drive the DNCP approach to DSM/EE programs, North Carolina should set its own policy on DSM/EE, even though95% of the parent utility's operations are in another state, as is the case with DNCP. Therefore, the Public Staff suggested that DNCP's relatively lower DSM/EE savings merit ongoing review and that a "market potential study" could be a useful tool to assess how actual DSM/EE savings compare to achievable savings. The Public Staff stated that a market potential study, accompanied by an end-use or baseline study of DSM/EE potential in North Carolina could show how actual savings compare to achievable savings. Such a study should be conducted periodically to reflect changing market and economic conditions, and may suggest ways to increase savings from existing programs, and may also identify additional programs or measures for use in North Carolina. DNCP completed a market potential study in 2014; however, the results of the study have not yet been released and the Public Staff has not yet reviewed it. The Public Staff opined that the best way to determine if the electric utilities are achieving the maximum feasible cost-effective DSM and EE savings would be for the Commission to order an independent market potential study.

Based upon the foregoing, the Commission finds and concludes that DNCP should file its 2014 Market Potential Study as soon as practicable with the Commission once such study is published and distributable. Further, the Commission finds and concludes that the Public Staff should provide comments regarding DNCP's 2014 Market Potential Study when it files testimony in DNCP's next annual DSM/EE rider proceeding.

With regard to the second question posed by the Commission in its October 3, 2014 Order- whether customer rate impacts from the DSM/EE rider for DNCP are reasonable- the Public Staff responded that rate impacts on customers are currently relatively minor. Further, the Public Staff commented that the rate impacts on customers are reasonable: (1) since the PPI is only a percentage of less than 100% of UCT net savings[1], it cannot, by definition, change a cost-effective program to a non-cost-effective program; and (2) since recovery of Net Lost Revenues (NLR) is designed to preserve pre-existing utility earnings, not add to them, revenue requirements in the aggregate do not increase over what they would have been in the absence of the program (although they may increase for individual non-participants).

DISCUSSION OF REVISIONS TO THE MECHANISM

Regarding the Mechanism Proposal, DNCP described the extensive collaborative discussions between the Company and the Public Staff that led to the Mechanism Proposal and highlighted certain notable changes. Specifically, DNCP requested approval to transition to a lagging calendar year experience modification factor (EMF) test period under the Mechanism Proposal. This proposed change to the EMF period mandated by Commission Rule R8-69(a)(5) would allow the Company more time between the end of its EMF test period (currently June 30th of the filing year) and the filing date of its annual cost recovery petition (filed approximately August 20th annually). The Company observed that the Commission had approved a similar waiver of Commission Rule R8-69(a)(5) for DEP in Docket No. E-2, Sub 931, and requested a similar waiver.[2] The Public Staff agreed with DNCP's proposal that the test years in future DSM/EE rider proceedings be calendar years (rather than the period from July through June).[3]

DNCP and the Public Staff also agreed to modify Paragraph 54(b) of the Mechanism to streamline the projected PPI to use a conservative estimation that then would be trued-up through the EMF in a future proceeding. Finally, beginning in 2017, DNCP and the Public Staff agreed that DNCP would switch to a portfolio-based performance incentive versus the existing (and continued through 2016 under the Mechanism Proposal) approach of calculating a program-based performance incentive. The Public Staff pointed out that in light of the slower start that DNCP has had for its DSM/EE programs – roughly a couple years behind DEP and Duke Energy Carolinas, LLC. (DEC) – the Public Staff and DNCP agreed that it is reasonable to continue the PPI calculation methodology of the existing DNCP Mechanism for two more years and then switch to the "portfolio" approach used by DEP and DEC. Further, DNCP and the Public Staff agreed to resume discussions prior to the 2017 DSM/EE rider proceeding to discuss the necessary revisions to the proposed Mechanism to accomplish such transition. Until then, the performance incentive percentages (8% for DSM and 13% for EE) would remain unchanged.

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[1] The parties noted that DNCP generally has cost-effectiveness test results of greater than 1.0 under the Utility Cost Test (UCT).

[2] DEP, Order Approving Revised Cost Recovery and Incentive Mechanism, Docket No. E-2, Sub 931 (Jan. 20, 2015).

[3] The Public Staff noted that such proposal, if approved, would necessitate that the test year in the next annual rider proceeding (2015) be only six months long.

Another item of change in the Proposed Mechanism concerns NLR and Net Found Revenues. As in the current Mechanism, the Public Staff recommended that NLR for any given period be subject to reduction by any increases in Net Found Revenues during the same period. As a new matter, the Public Staff recommended that DNCP activities be formally evaluated for Net Found Revenues by use of the same "Decision Tree" (which was included as Attachment A to the Mechanism Proposal) that has been approved by the Commission for use by DEC and DEP.

G.S. 62-133.9(d) authorizes the Commission to approve an annual rider to the rates of electric public utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new DSM and EE programs. The costs include, but are not limited to, all capital costs, including costs of capital and depreciation expense, administrative costs, implementation costs, incentive payments to participants, and operating costs. The Commission is also authorized to approve incentives for the utility for the adoption and implementation of new DSM and EE programs, including NLR and appropriate rewards based on the sharing of savings achieved by the programs. The annual DSM/EE rider is composed of two parts: (1) the utility's forecasted costs, along with incentives, during the rate period, and (2) an EMF to collect the difference between the utility's actual reasonable and prudent costs and incentives incurred during the test period and actual revenues realized during the test period.

The Commission has reviewed the filings of the parties in this proceeding, including the recommended Mechanism Proposal agreed to by DNCP and the Public Staff, and is of the opinion that the revised Mechanism constitutes a reasonable method to provide for recovery of costs and appropriate utility incentives related to DNCP's DSM and EE activities. Therefore, the Commission finds and concludes that the proposed revisions to the Mechanism agreed to by DNCP and the Public Staff, attached hereto as Appendix A, are reasonable and appropriate, serve the public interest, and should be approved. Further, the Commission finds and concludes that the incentives proposed in the Mechanism, including NLR and the PPI, subject to the restrictions set forth in the Mechanism Proposal and continuing review for reasonableness, are reasonable and appropriate and should be approved. The Commission also recognizes that DNCP and the Public Staff agreed that the performance incentive included in the Mechanism Proposal is appropriate for use during the next two years as a transition period, and that the parties will work together to revise this component of the Mechanism for use in 2017. Accordingly, these parties should file on or before March 1, 2017, an updated performance incentive proposal (or separate proposals if agreement cannot be reached) for the Commission's review and approval.

IT IS, THEREFORE, ORDERED as follows:

1. That the waiver of Commission Rule R8-69(a)(5) is granted to change the test period for DNCP's DSM/EE rider to align with the lagging calendar year, for the duration of the Mechanism, unless otherwise ordered by the Commission in the future. The initial test period for the 2015 Rider proceeding shall only be for a period of six months (July 2014 -- December 2014);

2. That the Mechanism filed by the Public Staff, and agreed to by DNCP, attached hereto as Appendix A, including Attachment A thereto, is hereby approved;

3. That the identification of Net Found Revenues for purposes of determining DNCP's recovery of DSM/EE NLR shall be governed by the provisions of the approved revised Mechanism, including Attachment A thereto;

4. That the attached Mechanism shall be effective as of the date of this Order for projecting DSM and EE costs and utility incentives in DNCP's 2015 DSM/EE rider proceeding for the period beginning on or after January 1, 2016, as well as for true-up of DSM and EE costs and utility incentives for the period beginning July 1, 2014 through December 21, 2014, and on a lagging calendar year basis thereafter;

5. That the Public Staff and DNCP shall initiate a limited review of performance incentive provisions of the Company's Mechanism, as agreed to in the Mechanism, and shall file on or before March 1, 2017, an updated performance incentive proposal (or separate proposals if agreement cannot be reached) for the Commission's review and approval;

6. That the Public Staff shall initiate a formal review of the Company's Mechanism not later than October 1, 2019, unless requested to do so earlier by the Commission, the Company, or another interested party. The Public Staff's 2019 review should specifically address whether the incentives in the Commission-approved Mechanism are producing significant DSM and EE results; whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate; and any other relevant issues that may be identified during the review process; and

7. That DNCP shall file its 2014 Market Potential Study with the Commission as soon as practicable after it is published and distributable and that the Public Staff shall file comments regarding DNCP's market potential study to be included in the Public Staff's prefiled testimony in DNCP's next annual DSM/EE rider proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of May, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX A
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COST RECOVERY AND INCENTIVE MECHANISM FOR DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS

The purpose of this Mechanism is (1) to allow Virginia Electric and Power Company (VEPCO), d/b/a Dominion North Carolina Power (DNCP or the Company) to recover all reasonable and prudent Costs incurred for adopting and implementing new demand-side management (DSM) and new energy efficiency (EE) Measures in accordance with G.S. 62-133.9, Commission Rules R8-68 and R8-69, the Commission's orders, and the additional principles set forth below; (2) to establish certain requirements, in addition to those of Commission Rule R8-68, for requests by DNCP for Commission approval of DSM and EE programs; (3) to establish the terms, conditions, and methodology to be used for the recovery of Net Lost Revenues and an additional incentive to reward DNCP for adopting and implementing new DSM and EE Measures and Programs, in cases where the Commission deems such recovery and reward appropriate; and (4) to address (a) customer opt-outs, (b) procedural matters, (c) cost allocation, (d) regulatory reporting requirements, and (e) future reviews of the Mechanism. The definitions set out in G.S. 62-133.8 and 62-133.9 and Commission Rules R8-68 and R8-69 apply to this Mechanism, except as otherwise provided for herein.

Changes in the terms and conditions of this Mechanism shall be applied prospectively only. Approved Programs and Measures shall continue to be subject to the terms and conditions that were in effect when they were approved with respect to the recovery of reasonable and prudent costs and Net Lost Revenues. With respect to the recovery of Program Performance Incentives, approved Programs and Measures shall continue to be subject to the terms and conditions in effect in the Vintage Year that any applicable Measurement Unit was installed.

The Mechanism may be adjusted where necessary to accommodate the specific characteristics of future DSM/EE Programs.

Definitions

1. *Common Costs* are Costs that are not attributable or directly assignable to specific DSM or EE Programs but are necessary to design, implement, and operate the Programs collectively.

2. *Costs* include Program Costs, Common Costs, and, subject to Rule R8- 69(b), the designated amounts dedicated for expenditure on efforts to promote general awareness of and education about EE and DSM activities, as well as research and development activities and the costs for pilot Programs.

3. *Low Income Programs or Low Income Measures* are DSM or EE Programs or Measures provided specifically to low income customers.

4. *Measure* means, with respect to EE, an “energy efficiency Measure,” as defined in G.S. 62-133.8(a)(4), that is new under G.S. 62-133.9(a) and refers to an equipment, physical, or program change that results in less energy used to perform the same function. With respect to DSM, a Measure refers to an activity, initiative, or Program change that is new under G.S. 62-133.9(a) and is undertaken by DNCP or its customers to reduce electricity use during peak demand periods or to shift the timing of electricity use from peak to non-peak demand periods. DSM includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.

5. *Measurement Unit* means the basic numerical unit that is used to measure and track the (a) incurred Costs; (b) Net Lost Revenues; and (c) net kilowatt (kW), kilowatt-hour (kWh), and

dollar savings for DSM or EE Measures installed in each Vintage Year. A Measurement Unit may be equivalent to an individual Measure or bundles of Measures. The establishment of Measurement Units shall be requested by DNCP and established by the Commission for each Program in the Program approval process, and shall be subject to modification by the Commission when appropriate. If Measurement Units have not been established for a particular Program, the Measurement Units for that Program shall be the individual Measures, unless the Commission determines otherwise.

6. *Net Found Revenues* means any net increases in revenues resulting from any activity by DNCP's public utility operations that causes a customer to increase demand or energy consumption, whether or not that activity has been approved pursuant to Rule R8-68. The dollar value of Net Found Revenues will be determined in a manner consistent with the determination of the dollar value of Net Lost Revenues provided in Paragraph No. 7 below. In determining which activities produce Net Found Revenues, the "Decision Tree" attached to this Mechanism as Attachment A will be applied.

7. *Net Lost Revenues* means DNCP revenue losses, net of fuel costs and non-fuel variable operating and maintenance expenses avoided at the time of the kilowatt-hour sale(s) lost due to the DSM or EE Measures, or in the case of purchased power, in the applicable billing period, incurred by DNCP's public utility operations as the result of a new DSM or EE Measure. Notwithstanding this definition, subject to review in future DSM/EE cost recovery proceedings and fuel and fuel-related cost proceedings, Net Lost Revenues may be calculated based on the average retail non-fuel base rate revenues per kWh, over a reasonably determined time period, applicable to the customer class impacted by the Measure, excluding the related customer charge component of those revenues, applied to the reduction in kWh sales resulting from the Measure, less any avoided non-fuel variable O&M expenses. When multiple customer classes are impacted by the DSM/EE Measures, a weighted net lost revenue calculation may be employed. Net Lost Revenues will be reduced by any applicable Net Found Revenues. Program Performance Incentives shall not be considered in the calculation of Net Lost Revenues.

8. *Portfolio* means the aggregation of DNCP DSM and EE Programs approved by the Commission, for a specified time period.

9. *Portfolio Performance Incentive* means a payment to DNCP as a bonus or reward for adopting and implementing new EE or DSM Programs. Upon implementation, the Portfolio Performance Incentive shall be based on the sharing of avoided cost savings, net of Program Costs and allocated Common Costs, achieved by those DSM and EE Programs in the aggregate (subject to certain exclusions). The Portfolio Performance Incentive excludes Net Lost Revenues.

10. *Program* means a collection of new DSM or EE Measures with similar objectives, which have been consolidated for purposes of delivery, administration, and cost recovery, and which have been or will be adopted on or after January 1, 2007, including subsequent changes and modifications.

11. *Program Costs* are costs that are directly attributable and expended solely for specific DSM or EE Programs, and include all appropriate capital costs (cost of capital, depreciation expenses, property taxes, and other associated costs found reasonable by the Commission), implementation costs, Evaluation, Measurement & Verification (EM&V) costs, incentive payments to Program participants, other operating and maintenance costs, and administrative and general costs incurred specifically for the Program, net of any grants, tax credits, or other reductions in cost received by the utility from outside parties and specifically related to the Program.

12. *Program Performance Incentive* means a payment to DNCP as a bonus or reward for adopting and implementing new EE or DSM Programs. The Program Performance Incentive is based on the sharing of avoided cost savings, net of Program Costs, achieved by those DSM and EE Measures or Programs, considered individually. For purposes of this Mechanism, subject to the provisions of Paragraph 51 herein, the Program Performance Incentive for Programs with negative net savings is set to zero. The Program Performance Incentive excludes Net Lost Revenues.

13. *Total Resource Cost (*TRC*) test* means a cost-effectiveness test that measures the net costs of a DSM or EE Program or Portfolio as a resource option based on the costs of the Program or Portfolio, including both the participants' costs and the utility's costs (excluding incentives paid by the utility to or on behalf of participants). The benefits for the TRC test are avoided supply costs (i.e., the reduction in generation capacity costs, transmission and distribution capacity costs, and energy costs), valued at marginal cost for the periods when there is a load reduction. The avoided supply costs shall be calculated using net Program or Portfolio savings (i.e., savings net of changes in energy use that would have happened even in the absence of the Program or Portfolio). The costs for the TRC test are the net Program or Portfolio costs incurred by the utility and the participants, plus the increased supply costs for any periods in which load is increased. All costs of equipment, installation, operation and maintenance, removal of equipment (less salvage value), and administration, no matter who pays for them, are

included in this test. However, Common Costs shall not be included in a Program-level TRC test used for Program approval purposes, but shall be included in a Portfolio-level TRC test. Any grants, tax credits, or other reductions in cost received by or known to the utility from outside parties and specifically related to the Program or Portfolio, as applicable, are considered a reduction to costs in this test.

14. *Utility Cost Test* (UCT) means a cost-effectiveness test that measures the net costs of a DSM or EE Program or Portfolio as a resource option based on the costs incurred by the utility (including incentive costs paid by the utility to or on behalf of participants) and excluding any net costs incurred by the participant. The benefits for the UCT are the avoided supply costs (i.e., the reduction in generation capacity costs, transmission and distribution capacity costs, and energy costs), valued at marginal cost for the periods when there is a load reduction. The avoided supply costs shall be calculated using net Program or Portfolio savings (i.e., savings net of changes in energy use that would have happened even in the absence of the Program or Portfolio). The costs for the UCT are the net Program or Portfolio Costs incurred by the utility, the incentives paid to or

on behalf of participants, and the increased supply costs for any periods in which load is increased. Utility costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, Program or Portfolio administration, and participant dropout and removal of equipment (less salvage value). However, Common Costs shall not be included in a Program-level UCT test used for Program approval purposes, but shall be included in a Portfolio-level UCT test. Any grants, tax credits, or other reductions in cost received by the utility from outside parties and specifically related to the Program or Portfolio, as applicable, are considered a reduction to costs in this test.

15. *Vintage Year* means a prescribed calendar year in which a specific DSM or EE Measure is installed for an individual participant or group of participants.

<u>Application for Approval of Programs</u>

16. In evaluating potential DSM/EE Measures and Programs for selection and implementation, DNCP will first perform a qualitative measure screening to ensure Measures are:

a. Applicable to the DNCP service area demographics and climate.
b. Feasible for a utility DSM/EE Program.

17. DNCP will then further screen EE and DSM Measures for cost-effectiveness. With the exception of Measures included in a Low Income Program, an EE or DSM Measure with a TRC test result less than 1.0 will not be considered further, unless the Measure can be bundled into an EE or DSM Program to enhance the overall cost-effectiveness of that Program.

18. With the exception of Low Income Programs, all Programs submitted for approval will meet the most restrictive cost benefit requirements in the jurisdictions which DNCP serves, but in no case will DNCP submit a Program that has TRC test or UCT results less than 1.00. For purposes of determining these test results, estimated incremental EM&V costs attributable to each Program shall be included in the Program costs.

19. DNCP will contact each party to its most recent DSM/EE cost recovery proceeding by March 1 of the following year and provide it with a list and description of Programs and Measures either currently being considered or planned for future consideration, and seek suggestions for additional Programs and Measures for consideration.

20. Nothing in this Mechanism relieves DNCP from its obligation to comply with Commission Rule R8-68 when filing for approval of DSM or EE Measures or Programs. As specifically required by Rule R8-68(c)(3), DNCP shall, in its filings for approval of Measures and Programs, describe in detail the industry-accepted methods to be used to collect and analyze data; measure and analyze Program participation; and evaluate, measure, and verify estimated energy and peak demand savings. DNCP shall also provide a schedule for reporting the results of this EM&V process to the Commission. The EM&V process description should describe not only the

methodologies used to produce the impact estimates utilized, but also any methodologies DNCP considered and rejected. Additionally, where known, DNCP shall identify the independent third party it plans to use for purposes of EM&V and include an estimate of all third-party costs in its filing. If not known at the time of filing for approval, this information shall be provided at the time of DNCP's next annual rider filing.

Opt-Out Eligibility Requirement

21. Commercial customers with annual consumption of 1,000,000 kWh or greater in the billing months of the prior calendar year and all industrial customers, who implement or will implement alternative DSM/EE Measures may, consistent with Commission Rule R8-69(d), elect not to participate in any utility-offered DSM/EE Measures and, after written notification to the utility, will not be subject to the DSM/EE rider and the DSM/EE Experience Modification (EMF) rider. For purposes of application of this option, a customer is defined to be a metered account billed under a single application of a Company rate tariff. For commercial accounts, once one account meets the opt-out eligibility requirement, all other accounts billed to the same entity with lesser annual usage located on the same or contiguous properties are also eligible to opt-out of the DSM/EE rider and DSM/EE EMF rider.

Procedural Matters

22. DNCP shall file its annual application for recovery of the DSM/EE and DSM/EE EMF riders not less than 84 days prior to the hearing scheduled in accordance with Commission Rule R8-69.

23. For purposes of DNCP's Integrated Resource Plan, and subject to continuing review for reasonableness, DNCP may include utility incentives calculated according to the methods accepted by the Virginia State Corporation Commission (VSCC) in DSM/EE Program Costs, and may exclude Common Costs from such Program Costs.

24. For purposes of developing the Company's Integrated Resource Plan, DNCP shall include the estimated or actual kW, kWh, and program costs, if known, associated with Low Income Programs and pilot DSM/EE programs in its calculations and modeling.

25. For purposes of DSM/EE Program approval filings, DNCP shall file the results of cost-effectiveness tests both including the utility incentives calculated according to the methods accepted by the VSCC and excluding the utility incentives, and will update Common Costs for its DSM/EE efforts to reflect any increases or decreases in specific and aggregate Common Costs since the last preceding Program approval filing or cost recovery proceeding, whichever is more recent.

26. Beginning in DNCP's 2016 DSM/EE rider proceeding, the test period used in the development of the DSM/EE EMF Rider will be the lagging calendar year preceding the year in which the case is filed (e.g., for the 2016 proceeding, January 1 through December 31, 2015). For

purposes of DNCP's 2015 DSM/EE rider proceeding, the test period used in the development of the DSM/EE EMF Rider for that case only shall be the six month period, July 1, 2014, through December 31, 2014.

Allocation Methodologies

27. For purposes of recovery through the DSM/EE rider, estimated 12-month system-level Common Costs shall be allocated to each Program on the basis of the estimated relative 12-month operating costs of each individual Program (including O&M, depreciation, property taxes, and insurance expenses), subject to continuing review of the overall reasonableness of the annual allocation. This allocation shall be trued up at the time that finalized and trued-up Costs for a given time period are included in the DSM/EE EMF.

28. For purposes of recovery through the DSM/EE rider, DNCP's system Costs for approved DSM and EE Programs and Measures, including allocated Common Costs, shall be allocated, by Program, to retail jurisdictions as follows: (i) the North Carolina retail jurisdiction, (ii) the Virginia retail jurisdiction, and (iii) Virginia non-jurisdictional

customers excluding contract classes that have elected not to participate and excluding customers in participating contract classes that are exempt or have opted out.[1] The wholesale jurisdiction shall not be allocated any Costs for approved DSM and EE Programs and Measures, including allocated Common Costs. The allocation factors used to allocate the estimated rate period Costs of DSM and EE Programs shall be the generation-level retail coincident peak and energy allocation factors, respectively, for the most recently completed test year at the time the annual cost recovery filing is made.

29 Notwithstanding paragraph 28 above, and to the extent it could impact the Company's peak demand and energy allocation factors and its ability to recover total system costs, should the Company determine: (1) that the Company expects that any caps imposed by the VSCC will limit participation by its Virginia retail jurisdictional customers in DSM and EE programs that are comparable to those approved by the NCUC,[2] or (2) that any other action by a state legislative or regulatory body, including a statute, rule, or order rejecting the Company's application for approval of a DSM or EE program in the Virginia retail jurisdiction over the long term will likewise

[1] Virginia Non-jurisdictional customers are not subject to the jurisdiction of the Virginia State Corporation Commission. These are customers that have contracts with Virginia Electric and Power Company for service. The County and Municipal class, the Commonwealth of Virginia class, the NASA class, and the Non-jurisdictional Outdoor Lighting class are the "contract classes that have elected not to participate" and are not participating in DSM/EE Programs. The MS class is what is meant by "customers in participating contract classes" and represents large military and federal government customers that take service under Virginia jurisdictional rates. Certain of the MS class of customers are exempt or may opt out of participation in DSM/EE Programs and payment of DSM/EE cost recovery riders.

[2] DSM or EE programs not approved by the Commission are not eligible for recovery through the DSM/EE or DSM/EE EMF riders, and thus would not be subject to this provision.

limit participation by customers in either of the retail jurisdictions relative to the other, DNCP will schedule a meeting with the Public Staff to discuss these matters. This initial meeting shall be scheduled to take place no later than two months prior to the expected date of the filing of DNCP's annual application for DSM/EE cost recovery, and shall focus on whether the North Carolina retail jurisdictional allocation factors used in the proceeding should be adjusted to reflect this limitation, and, if so, how the factors should be adjusted. DNCP will report on the outcome of these discussions in the direct testimony included in its next occurring cost recovery proceeding filing. The Public Staff recognizes that the types of limitations discussed herein may impact the Company's ability to fully recover its system level DSM/EE costs in a manner that differs from that caused simply by different jurisdictions utilizing differing allocation methodologies, and agrees to carefully consider any such impacts in the course of its discussions with DNCP and in its ultimate recommendations to the Commission.

30. With regard to paragraph 29 above, any such discussions between the Company and the Public Staff shall take into account the methodology and process approved by the Commission in Docket No. E-22, Sub 494, as Addendum II to the DSM/EE stipulation and mechanism originally approved in 2011 in Docket No. E-22,

Sub 464. This methodology and process is based on the principle that for as long as Programs are offered to only North Carolina retail customers, 100% of the incremental costs of the Programs may be allocated to North Carolina retail jurisdictional operations for purposes of the annual DSM/EE cost recovery proceedings, provided that a reasonable estimate of 100% of the applicable incremental savings from the Programs shall also be allocated to North Carolina retail operations. It consists of an approach that involves comparing the avoided cost of the applicable Programs to the amount of savings that will naturally flow to the North Carolina retail ratepayers through the operations of the Company's jurisdictional cost of service study, and then "truing up" any difference between the two in the annual DSM/EE cost recovery proceedings. Such a "truing up" could result in a positive or a negative adjustment. As part of this approach, the impact on the jurisdictional cost of service study of the Commercial Distributed Generation Program, which is currently offered by VEPCO only in Virginia, is also considered. To the extent this methodology and process is used, the Public Staff will be responsible for evaluating whether an adjustment is necessary as part of the annual DSM/EE cost recovery proceeding, including obtaining through the discovery process the information necessary to make the calculations.

31. For purposes of recovery through the DSM/EE rider, DNCP's North Carolina retail jurisdictional Costs for approved DSM and EE Programs and Measures (including allocated Common Costs), as determined in accordance with paragraphs 27 through 30 of this Mechanism, shall be assigned or allocated to North Carolina retail customer classes based on the particular classes at which each Program is targeted. If a Program is targeted at more than one customer class, the Costs of that Program (including Common Costs) shall be allocated among the targeted classes in a reasonable manner. The allocation factor used to allocate the Costs of such DSM Programs shall be the generation-level retail coincident peak factor for the applicable calendar year. The allocation factor used to allocate the Costs of such EE Programs shall be the generation level energy

allocation factor for the applicable calendar year. The assignments and allocations of Costs shall be trued up at the time that finalized and trued-up Costs for a given time period are passed through the DSM/EE EMF.

32. For purposes of the allocation/assignment procedure described in paragraph 31 above, and subject to continuing review, DNCP shall exclude the peak demand and energy usage of customers electing to opt out in accordance with this Mechanism. For purposes of recovery through the DSM/EE rider, the North Carolina retail jurisdictional allocation factors developed pursuant to paragraphs 28 through 30 above shall not reflect the effect of opted-out customers in the North Carolina retail jurisdiction or exempt and opted-out customers in the Virginia retail jurisdiction.

Cost Recovery

33. As provided in Rule R8-69 and G.S. 62-133.9(d), but subject to the specific provisions and/or modifications contained in this Mechanism, DNCP shall be allowed to recover, through the DSM/EE rider, all reasonable and prudent Costs reasonably and

appropriately estimated to be incurred in expenses, during the current rate period, for DSM and EE Programs that have been approved by the Commission under Rule R8-68.

34. As permitted by G.S. 62-133.9(d), any of the Stipulating Parties may propose a procedure for the deferral and amortization in future DSM/EE riders of all or a portion of DNCP's reasonable and prudent non-capital Costs to the extent those costs are intended to produce future benefits.

35. The DSM/EE EMF rider shall reflect the difference between the reasonable and prudent Costs incurred or amortized during the applicable test period and the revenues actually realized during such test period under the DSM/EE rider then in effect.

36. The cost and expense information filed by DNCP pursuant to Commission Rules R8-68(c) and R8-69(f) shall be categorized by Measurement Unit and Vintage Year.

37. For Program Costs not deferred for amortization in future DSM/EE riders pursuant to paragraph 34 above, the accrual of a return on any under-recoveries or over-recoveries of costs will follow the requirements of Commission Rule R8-69(b), subparagraphs (3) and (6), unless the Commission determines otherwise.

38. Subject to review in the annual DSM/EE cost recovery proceedings, the rate of return on investment used by DNCP on an ongoing monthly or other reasonable basis to determine DSM/EE capital-related costs will be based on the capital structure, embedded cost of preferred stock, and embedded cost of debt of the Company (net of appropriate income taxes) specified by DNCP's Treasury Department for use in the Company's NCUC ES-1 Reports or other North

Carolina retail earnings or return calculations for the period in which the capital investment costs are incurred, and the cost of common equity approved in the Company's then most recent general rate case.

39. In each annual DSM/EE cost recovery filing, DNCP shall (a) perform prospective cost-effectiveness test evaluations for each of its approved DSM and EE Programs that has been implemented for at least 12 months, (b) perform prospective aggregated Portfolio-level cost-effectiveness test evaluations for its approved DSM/EE Programs (including Common Costs) that have been implemented for at least 12 months, and (c) include these cost-effectiveness test results in its DSM/EE rider application along with a discussion of whether those results indicate that any of the Programs should be discontinued or modified.

Net Lost Revenues

40. Unless otherwise ordered by the Commission, when authorized pursuant to Rule R8-69(c), DNCP shall be permitted to recover, through the DSM/EE EMF riders, Net Lost Revenues associated with the implementation of approved DSM and EE Programs, subject to the restrictions set out below. The recovery of Net Lost Revenues

only through the DSM/EE EMF riders will be subject to continuing review for reasonableness.

41. The North Carolina retail kWh sales reductions that result from an approved Measurement Unit installed in a given Vintage Year shall be eligible for use in calculating Net Lost Revenues eligible for recovery only for the first 36 months after the installation of the Measurement Unit. Thereafter, such kWh sales reductions will not be eligible for calculating recoverable Net Lost Revenues. The actual recovery of Net Lost Revenues associated with an approved Measurement Unit will begin no later than the commencement of the final true-up of the Program Performance Incentive for the same Measurement Unit.

42. Programs or Measures with the primary purpose of promoting general awareness and education of EE and DSM activities, as well as research and development activities, are ineligible for the recovery of Net Lost Revenues.

43. In order to recover Net Lost Revenues associated with a pilot Program or Measure, DNCP must, in its application for Program or Measure approval, demonstrate (a) that the Program or Measure is of a type that is intended to be developed into a full-scale, Commission-approved Program or Measure, and (b) that DNCP will implement an EM&V plan based on industry-accepted protocols for the Program or Measure. No pilot Program or Measure will be eligible for Net Lost Revenue recovery unless it (a) is ultimately proven to have been cost-effective and (b) is developed into a full-scale, commercialized Program.

44. Notwithstanding the allowance of recovery of 36 months' Net Lost Revenues associated with eligible kWh sales reductions in paragraph 41 above, the kWh sales reductions that

result from Measurement Units installed shall cease being eligible for use in calculating recoverable Net Lost Revenues as of the effective date of (a) a Commission-approved alternative recovery mechanism that accounts for the eligible recoverable Net Lost Revenues associated with eligible kWh sales reductions, or (b) the implementation of new rates approved by the Commission in a general rate case or comparable proceeding to the extent the rates set in the general rate case or comparable proceeding are set to explicitly or implicitly recover the Net Lost Revenues associated with those kWh sales reductions.

45. Total recoverable Net Lost Revenues as measured for the 36-month period identified in paragraph 41 above shall be reduced by Net Found Revenues that occur during the same 36-month period, determined by application of the "Decision Tree" attached to this Mechanism as Attachment A.

46. Recoverable Net Lost Revenues shall ultimately be based on kWh sales reductions and kW savings verified by the EM&V process and approved by the Commission. Recoverable Net Lost Revenues shall be estimated and trued-up, on a Vintage Year basis, in the following manner:

(a) As part of the DSM/EE rider approved in each annual cost and incentive recovery proceeding, DNCP shall be allowed to recover the appropriate and reasonable level of recoverable Net Lost Revenues associated with each applicable Program and Vintage Year (subject to the limitations set forth in this Mechanism), estimated to be experienced during the rate period for which the DSM/EE rider is being set.

(b) Recoverable Net Lost Revenues related to any given Program/Measure and Vintage Year shall be trued-up through the DSM/EE EMF rider in subsequent annual cost and incentive recovery proceedings based on the Commission-approved results of the appropriate EM&V studies related to the Program/Measure and Vintage Year. The true-up shall be based on verified savings and shall be applied to prospective and past time periods, as applicable.

(c) The true-up shall be calculated based on the difference between projected and actual recoverable Net Lost Revenues for each Program and period under consideration, accounting for any differences derived from the completed and reviewed EM&V studies, including: (1) the projected and actual number of installations/implementations per Measurement Unit; (2) the projected and actual net kilowatt-hour (kWh) and kilowatt (kW) savings per installation; (3) the projected and actual recoverable gross lost revenues per kWh and kW saved; and (4) the projected and actual deductions from recoverable gross lost revenues per kWh and kW saved.

(d) The reduction in recoverable Net Lost Revenues due to Net Found Revenues shall be trued up in a manner consistent with the true-up of recoverable Net Lost Revenues.

(e) The combined total of all Vintage Year true-ups calculated in a given year's Rule R8-69 proceeding shall be incorporated into the appropriate DSM/EE EMF billing factor.

Program Performance Incentive

47. For Vintage Years 2014, 2015, and 2016, when authorized pursuant to Rule R8-69(c), DNCP shall be allowed to collect a Program Performance Incentive for each DSM or EE Program approved and in effect during a given Vintage Year, subject to the restrictions set out below.

48. Programs, Measures, and activities undertaken by DNCP with the primary purpose of promoting general awareness of and education about EE and DSM activities, as well as research and development activities, are ineligible to receive a Program Performance Incentive.

49. A Pilot Program or Measure shall not be eligible for a Program Performance Incentive unless (a) DNCP specifically requests and receives approval of Program Performance Incentive inclusion when it applies for approval of that Program or Measure, and (b) the Program or Measure is ultimately developed into a full-scale, commercialized Program. However, for purposes of Program Performance Incentive determination, pilot Programs and Measures shall be included, as appropriate, in dispatch calculations to determine avoided kW and kWh associated with Programs eligible for a Program Performance Incentive.

50. Low Income Programs shall not be eligible for a Program Performance Incentive. However, for purposes of Program Performance Incentive determination, Low Income Programs shall be included, as appropriate, in dispatch calculations to determine avoided kW and kWh associated with Programs eligible for a Program Performance Incentive.

51. For any Vintage Year in which a Program's TRC test result is less than 1.00, calculated using Commission-approved EM&V results, there shall be a rebuttable presumption that the Program Performance Incentive for that Program for the applicable Vintage Year is zero. DNCP shall be allowed an opportunity to rebut the presumption that the Program Performance Incentive should be zero, by showing the impact of weather, decline in avoided costs, market forces, or other factors beyond DNCP's control.

52. The Program Performance Incentive shall be based on the net dollar savings of each Program, as calculated using the UCT, on a total system basis. The North Carolina retail jurisdictional and class portions of the system-basis net savings shall be determined in accordance with the Allocation Procedures Section of this Mechanism. The total of the Program Performance Incentives for all Programs shall be added to DNCP's DSM/EE or DSM/EE EMF recovery riders, as appropriate.

53. In its annual filing pursuant to Rule R8-69(f), DNCP shall file an exhibit that indicates for each active Program, the annual projected and actual utility costs, participant costs, number of Measurement Units installed or used, average per kW and kWh impacts for each Measurement Unit (potentially qualified as appropriate, for projected impacts, pursuant to Paragraph 54(b) of this Mechanism), and per kW and kWh avoided costs for each Measurement Unit, consistent with the UCT, related to the applicable Vintage Year installations that it requests or may request the Commission to approve. Upon its review, the Commission will make findings based on DNCP's annual filing for each Program for which an estimated or trued-up Program Performance Incentive is approved.

54. Unless the Commission determines otherwise in an annual DSM/EE rider proceeding, the estimated Program Performance Incentive initially to be recovered (subject to later true-up) shall be calculated as follows:

a. The amount of the pre-income tax Program Performance Incentive initially to be recovered for a given Program and Vintage Year shall be equal to 8% for DSM Programs and 13% for EE Programs, multiplied by the present value of the estimated net dollar savings associated with the Measurement Units installed in that Vintage Year, calculated by Program using the UCT (excluding certain Programs, as appropriate). The present value of the estimated net dollar savings shall be the difference between the present value of the annual lifetime avoided cost savings for Measurement Units projected to be installed in that Vintage Year and the present value of the annual lifetime Program Costs for those Measurement Units. The annual lifetime avoided cost savings for Measurement Units installed in the applicable Vintage Year shall be calculated by multiplying the number of each specific type of Measurement Unit projected to be installed in that Vintage Year by the most current estimates of each lifetime year's per installation kW and kWh savings and by the most current estimates of each lifetime year's per kW and kWh avoided costs (as determined pursuant to paragraphs 56 and 57 below). In calculating the forecasted initial Program Performance Incentive it will be assumed that projections will be achieved.

b. Notwithstanding subparagraph 54(a) above, for purposes of calculating the present value of the estimated net dollar savings associated with the Measurement Units installed in the Vintage Year, DNCP may utilize a reasonable and appropriate estimation accomplished by a simpler and conservative method, except that DNCP must still determine each lifetime year's per kW and kWh avoided costs pursuant to the provisions of paragraphs 56 and 57 below, in the same manner as would have been used pursuant to subparagraph 54(a).

55. Unless the Commission determines otherwise in an annual DSM/EE rider proceeding, the initial Program Performance Incentive shall be converted into a stream of no more than 10 levelized annual payments, accounting for and incorporating DNCP's overall weighted average net-of-tax rate of return approved in DNCP's most recent general rate case as the appropriate interest (discount) rate.

56. For purposes of the Program Performance Incentive, the per kW avoided capacity costs used to calculate net savings for a Program and Vintage Year shall be determined annually by DNCP using comparable methodologies to those used in the most recently approved biennial avoided cost proceeding. The per kWh avoided energy costs shall be those reflected in or underlying the most recently filed integrated resource plan (IRP). DNCP's assumptions used in these methodologies, as well as the methodologies, are subject to the Public Staff's review and acceptance at the time DNCP files its petition for annual cost recovery pursuant to Rule R8-69 and this Mechanism. Unless DNCP and the Public Staff agree otherwise, DNCP shall not be allowed to update its avoided capacity costs and avoided energy costs after filing its petition for its annual cost recovery proceeding pursuant to Rule R8-69 and this Mechanism and prior to the

Commission's order establishing the rider for that rate period for purposes of calculating the Program Performance Incentive.

57. The per kW avoided transmission and avoided distribution (avoided T&D) costs used to calculate net savings for a Vintage Year shall be based on a study updated at least every five years, or as appropriate and agreed to by the Company and the Public Staff.

58. The Program Performance Incentive for each Vintage Year shall ultimately be based on net dollar savings as verified by the EM&V process and approved by the Commission. The Program Performance Incentive for each Vintage Year shall be trued-up as follows:

a. As part of the DSM/EE rider approved in each annual cost and incentive recovery proceeding, DNCP shall be allowed to recover an appropriately and reasonably estimated Program Performance Incentive (subject to the limitations set forth in this Mechanism) associated with the Vintage Year covered by the rate period in which the DSM/EE rider is to be in effect.

b. The Program Performance Incentive related to any given Vintage Year shall be trued-up through the DSM/EE EMF rider in subsequent annual cost and incentive recovery proceedings based on the Commission-approved results of the appropriate EM&V studies related to the program/measure and Vintage Year. The true-up shall be based on approved Measurement Units and shall cover all applicable time periods from the time period covered by the Measurement Unit's previous EM&V analysis or, if no previous EM&V analysis has taken place, the date of Program or Measure approval.

c. The amount of the Program Performance Incentive ultimately to be recovered for a given Program and Vintage Year shall be based on the present value of the actual net dollar savings derived from all Measurement Units installed in that Vintage Year specific to the Program, calculated using the UCT. The present value of the actual net dollar savings shall be the difference between the present value of the annual lifetime avoided cost savings for Measurement

Units installed in that Vintage Year and the present value of the annual lifetime program costs for those Measurement Units. The annual lifetime avoided cost savings for Measurement Units installed in the applicable Vintage Year shall be calculated by multiplying the number of each specific type of Measurement Unit installed in that Vintage Year by each lifetime year's per installation kW and kWh savings (as verified by the appropriate EM&V study) and by each lifetime year's per kW and kWh avoided costs as determined pursuant to paragraphs 56 and 57 when calculating the initially estimated Program Performance Incentive

for the Vintage Year. DNCP shall make all reasonable efforts to ensure that all vintages are fully trued-up within 24 months of the vintage program year.

59. The combined total of all Vintage Year true-ups of the Program Performance Incentive calculated in a given year's Rule R8-69 proceeding shall be incorporated into the appropriate DSM/EE EMF billing factor.

60. Beginning with Vintage Year 2017, DNCP will switch from calculating a Program Performance Incentive for inclusion in its DSM/EE and DSM/EE EMF riders to calculating a Portfolio Performance Incentive. DNCP and the Public Staff shall meet prior to the 2017 DSM/EE rider proceeding to discuss the appropriate revisions to this Mechanism necessary to accomplish this change, and the two parties shall present their joint or separate recommendations to the Commission in that proceeding.

Other Provisions

61. In its quarterly NCUC ES-1 Reports to the Commission, DNCP shall calculate and present its primary North Carolina retail jurisdictional earnings by including all actual EE and DSM program revenues, including Program Performance Incentive and recoverable Net Lost Revenue incentives, and costs. Additionally, DNCP shall prepare and present (a) supplemental schedules setting forth its North Carolina retail jurisdictional earnings excluding the effects of the Program Performance Incentive; (b) supplemental schedules setting forth its North Carolina retail jurisdictional earnings excluding the effects of the Company's EE and DSM Programs; and (c) supplemental schedules setting forth earnings, including overall rates of return, returns on common equity, and margins over Program Costs (including Common Costs) actually realized from its EE and DSM Programs in total and stated separately by Program class (Program classes are hereby defined to be (i) EE Programs and (ii) DSM Programs). Detailed workpapers shall be provided for each scenario described above. Such workpapers, at a minimum, shall clearly show actual revenues, expenses, taxes, operating income, rate base/investment, including components, and the applicable capitalization ratios and cost rates, including overall rate of return and return on common equity.

62. The terms and conditions of this Mechanism shall be reviewed by the Commission every four years unless otherwise ordered by the Commission. However, any intervenor may request the Commission to initiate such a review at any time within the four year period. The

Company and other parties shall submit any proposed changes to the Commission for approval at the time of the Company's annual DSM/EE rider filing. During the time of review, the Mechanism shall remain in effect until further order of the Commission revising the terms of the Mechanism or taking such other action as the Commission may deem appropriate.

ATTACHMENT A
Page 1 of 2

Attachment A

A "decision tree" will be used to evaluate whether activities that may directly or indirectly result in increases in customer demand or energy consumption should be designated by the Company as producing "found revenues" and either filed with the Commission for a determination of their status or reported to the Commission for consideration at its discretion. The Company will create a list of all DNCP activities that may produce found revenues by directly or indirectly resulting in an increase in customer demand or energy consumption within the Company's service territory, followed by the elimination, or "filtering out," of activities that meet certain criteria. More specifically, an activity will be eliminated from the list if it meets one or more of the following criteria (the tree itself should be referred to for the precise language of each filter):

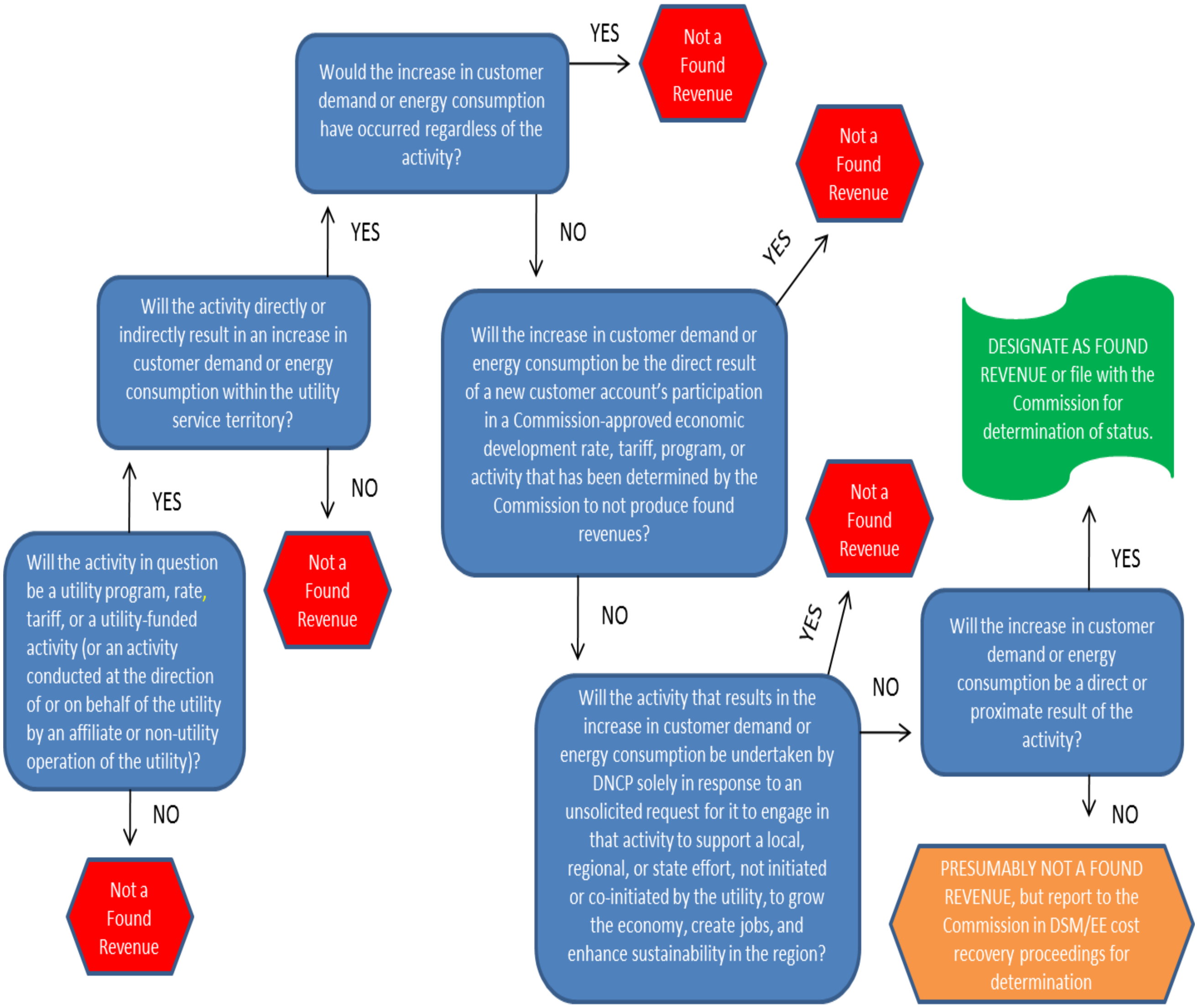
(1) The increase in customer demand or energy consumption would have occurred regardless of the activity.

(2) The increase is the result of a new customer account's participation in certain DNCP economic development activities that have been found by the Commission not to result in found revenues.

(3) The activity is conducted at the unsolicited request of a governmental unit for the purposes of growing the economy, creating jobs, or enhancing sustainability in the region.

If an activity is not eliminated for consideration by one of these filters, DNCP will then evaluate whether the related increase in customer demand or energy consumption is a direct or proximate result of the activity. If it is determined to be so, the Company will designate the activity as one producing found revenues or submit it to the Commission for determination; if not, the Company may presume that the activity does not produce found revenues but will report it to the Commission as part of its annual DSM/EE cost recovery filing. A visual representation of the "decision tree" process follows on the next page.

"Net lost revenues shall also be net of any increases in revenues resulting from any activity by the electric public utility that increases customer demand or energy consumption, whether or not that activity has been approved pursuant to this Rule R8-68." - Commission Rule R8-68(b)(5)



DOCKET NO. E-22, SUB 524

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	))))))	ORDER APPROVING DSM/EE RIDER AND REQUIRING FILING OF PROPOSED CUSTOMER NOTICE

HEARD: Monday, November 2, 2015, at 1:50 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chairman Edward S. Finley, Jr.; Commissioners Bryan E. Beatty, Don M. Bailey, Jerry C. Dockham and James G. Patterson

APPEARANCES:

FOR DOMINION NORTH CAROLINA POWER:

E. Brett Breitschwerdt, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

FOR THE USING AND CONSUMING PUBLIC:

David T. Drooz, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: General Statute 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management and energy efficiency (DSM/EE) programs. In accordance with Commission Rule R8-69(b), such rider consists of the utility's reasonable and appropriate estimate of expenses expected to be incurred during the rate period and an experience modification factor (EMF) rider to collect or refund the difference between the utility's actual reasonable and prudent costs incurred during the test period and actual revenues realized during the test period under the DSM/EE rider then in effect. The Commission is also authorized to award incentives to electric utilities for adopting and implementing new DSM/EE programs, including appropriate rewards based on the sharing of savings achieved by the programs. These utility incentives are included in the utility's reasonable and appropriate estimate of expenses expected to be incurred during the rate period and in the DSM/EE EMF riders described above.

Further, Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric utility to establish an annual DSM/EE rider to recover DSM/EE related costs and utility incentives. Commission Rule R8-69(e) provides that the annual DSM/EE cost recovery rider hearing for each public utility will be scheduled as soon as practicable after the annual fuel and fuel-related charge adjustment proceeding held by the Commission for the electric public utility under Commission Rule R8-55.

On August 10, 2015, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP or the Company), filed in this docket its Application for Approval of Cost Recovery for Demand-Side Management and Energy Efficiency Measures (Application), seeking approval of new DSM/EE rider rates to recover the Company's reasonable and prudent DSM/EE program costs, common costs, taxes, net lost revenues (NLR), and a DSM/EE Program Performance Incentive (PPI).

Pertinent Proceedings in Prior Dockets

The Commission most recently approved DNCP's recovery of its reasonable and prudent DSM/EE costs and utility incentives by Order issued on December 19, 2014, in Docket No. E-22, Sub 513.

On October 14, 2011, in Docket No. E-22, Sub 464, the Commission issued its Order Approving Agreement and Stipulation of Settlement, Approving DSM/EE Rider, and Requiring Compliance Filing (2010 Cost Recovery Order). In the 2010 Cost Recovery Order, the Commission approved the Agreement and Stipulation of Settlement between the Public Staff and the Company (Stipulation), filed on March 2, 2011, as well as the Cost Recovery and Incentive Mechanism (Mechanism), attached as Stipulation Exhibit 1 to the Stipulation (collectively, Stipulation and Mechanism).

On December 13, 2011, in Docket No. E-22, Sub 473, the Commission issued its Order Approving DSM/EE Rider and Requiring Customer Notice in DNCP's 2011 DSM/EE cost recovery proceeding (2011 Cost Recovery Order). The 2011 Cost Recovery Order also approved a first Addendum to the Stipulation and Mechanism (Addendum I) related to jurisdictional allocation of DSM/EE costs. Addendum I was then incorporated as part of the Stipulation and Mechanism.

On April 29, 2013, in Docket No. E-22, Sub 486, the Commission issued its Order Granting Conditional Approval of Cost Assignment Proposal that approved a cost assignment methodology for allocating 100% of the incremental costs of DNCP's prospective North Carolina-only Commercial Lighting Program and HVAC Upgrade Program to the North Carolina retail jurisdiction. On December 18, 2013, in Docket No. E-22, Sub 494, the Commission approved this cost assignment methodology for programs offered only in North Carolina as the second Addendum to the Stipulation and Mechanism (Addendum II). Addendum II was then incorporated as part of the Stipulation and Mechanism.

On May 7, 2015, in Docket No. E-22, Sub 464, the Commission also issued its Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waiver (Order on

Revised Mechanism). The Order on Revised Mechanism approved an updated Cost Recovery and Incentive Mechanism for Demand Side Management and Energy Efficiency Programs (Revised Mechanism). The Revised Mechanism is effective for projected DSM/EE costs and utility incentives on and after January 1, 2016, and for true-up of DSM/EE costs and utility incentives for the period beginning July 1, 2014, through December 31, 2014, and on a lagging calendar year basis thereafter. The Revised Mechanism replaced the similar Mechanism that had been in effect since 2011.

Proceedings in the Present Docket

On August, 10, 2015, DNCP filed its Application for Approval of Cost Recovery for Demand-Side Management Programs and Energy Efficiency Measures consisting of the direct testimony of Michael T. Hubbard, and the direct testimonies and exhibits of Ripley C. Newcomb, David L. Turner, C. Alan Givens, Timothy P. Stuller and Debra A. Stephens. In summary, DNCP's Application seeks recovery of DNCP's reasonable and appropriate estimate of expenses expected to be incurred during the rate period, Rider C, and an EMF rider< Rider CE, to collect or refund the difference between DNCP's actual reasonable and prudent costs incurred during the test period and actual revenues realized during the test period under the DSM/EE rider presently in effect.

On August 26, 2015, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. Pursuant to this Order, the Commission established deadlines for the filing of petitions to intervene, intervenor testimony and exhibits, and Company rebuttal testimony and exhibits, scheduled a hearing to be held on Monday, November 2, 2015, in Raleigh, North Carolina, and required DNCP to publish a customer notice.

The intervention and participation in this docket by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On September 16, 2015, DNCP filed revised Testimony and exhibits of Ripley C. Newcomb and Timothy P. Stuller.

On October 9, 2015, DNCP filed supplemental testimony of David L. Turner, C. Alan Givens, Timothy P. Stuller, and Deborah A, Stephens.

On October 14, 2015, DNCP filed its Affidavit of Publication indicating that it had provided notice in newspapers of general circulation.

On October 16, 2015, the Public Staff filed the testimony of Jack L. Floyd, Engineer, Electric Division. Also on October 16, 2015, the Commission granted the Public Staff an extension of time until October 19, 2015, to file an affidavit or testimony of its accounting witness. On October 19, 2015, the Public Staff filed the affidavit and exhibits of Michael C. Maness, Assistant Director, Accounting Division.

On October 26, 2015, DNCP filed rebuttal testimony and exhibits of its witnesses Michael T. Hubbard, Ripley C. Newcomb, and C. Alan Givens.

On October 27, 2015, the Public Staff and DNCP filed a Joint Motion to excuse witnesses from appearing at the November 2, 2015 expert witness hearing, stating that they had reached agreement on all issues in this docket and had agreed to waive cross-examination of each other's witnesses. On October 28, 2015, the Commission issued an Order granting the Joint Motion.

No other parties intervened or presented testimony in this docket.

On November 2, 2015, the Commission held the public hearing as scheduled. No public witnesses appeared at the hearing. The Commission accepted into evidence the testimony, affidavits and exhibits of the witnesses for DNCP and the Public Staff.

On November 30, 2015, DNCP and the Public Staff filed a Joint Proposed Order.

Based upon DNCP's Application, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Virginia Electric and Power Company (VEPCO) operates in the State of North Carolina as DNCP. VEPCO, d/b/a DNCP, is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility.

2. DNCP is lawfully before the Commission based upon its Application filed pursuant to G.S. 62-133.9 and Commission Rule R8-69.

3. Pursuant to the Revised Mechanism, the rate period for purposes of this proceeding is the 12-month period of January 1, 2016, through December 31, 2016.

4. Pursuant to the Revised Mechanism, the test period for purposes of this proceeding is the 6-month period of July 1, 2014, through December 31, 2014.

5. DNCP has requested rate period recovery of costs and utility incentives related to the following approved DSM/EE programs: (a) Phase I Air Conditioner Cycling Program; (b) Phase II DSM/EE programs: Non-residential Energy Audit Program, Non-residential Duct Testing & Sealing Program, Residential Home Energy Check-Up Program, Residential Duct Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program; (c) Phase III DSM/EE programs: Non-residential Lighting Systems & Controls Program, Non-residential Heating & Cooling Efficiency Program, and Non-residential Window Film Program; (d) the 2015 North Carolina-only Low Income Program; and (e) the Phase IV Income and Age Qualifying Home Improvement Program. In addition, certain costs and utility incentives from the now-closed Residential Lighting, Commercial Lighting, and Commercial HVAC programs are included in DNCP's request and have been identified by the Public Staff as appropriate for recovery.

6. Recovery of forecasted DSM/EE program costs, common costs, NLR, and PPI, as well as a true-up of test period DSM/EE program costs, common costs, NLR, and PPI, is subject to the terms of the Revised Mechanism. DNCP should be allowed to recover reasonable and appropriate projected rate period costs and utility incentives, as well as reasonable and appropriate actual test period amounts, associated with offering each of its former, ongoing, and newly approved programs as described in its Application. The recovery of reasonable and appropriate program costs, common costs, NLR, and PPI is consistent with the Revised Mechanism previously approved by the Commission.

7. Recovery of incremental common costs not directly related to specific DSM or EE programs, as well as a utility incentive in the form of a PPI, is reasonable and consistent with the Revised Mechanism.

8. DNCP is not seeking recovery of projected period NLR in Rider C, and its request to true-up NLR in Rider CE in future proceedings is reasonable.

9. DNCP's $3,403,731 estimate of its North Carolina retail DSM/EE total projected rate period revenue requirement, consisting of DSM/EE program costs, common costs, and a PPI, is reasonable. However, it is also reasonable to design Rider C rates to collect a lower revenue amount, as proposed by the Company, in order to stay within the rates set forth in the public notice. The difference between revenue collected through Rider C and the total reasonable and appropriate DSM/EE costs and utility incentives for the 2016 rate period will be recovered through the DSM/EE EMF riders in future proceedings.

10. For purposes of determining its DSM/EE EMF, Rider CE, DNCP's reasonable and prudent North Carolina retail total revenue requirement for the DSM/EE EMF test period, consisting of DSM/EE program costs, common costs, and utility incentives, is ($91,603). This DSM/EE EMF refund includes interest of 10% on the over-recovery amount, as contemplated by Commission Rule R8-69(b)(3) and the Revised Mechanism.

11. Rider C as proposed by the Company and the Public Staff is reasonable and appropriate, and consists of the following customer class billing factors, including the North Carolina regulatory fee: Residential – 0.130 ¢/kWh; Small General Service and Public Authority – 0.090 ¢/kWh; Large General Service – 0.087 ¢/kWh; 6VP-- 0.106 ¢/kWh; and no charge for NS, Outdoor Lighting, and Traffic Lighting. It is reasonable and appropriate for Rider C to become effective for usage on and after January 1, 2016.

12. Rider CE is reasonable and appropriate, and consists of the following decrements to customer class billing factors, including the North Carolina regulatory fee: Residential – (0.003) ¢/kWh; Small General Service and Public Authority -- (0.003) ¢/kWh; Large General Service – (0.003) ¢/kWh; 6VP -- (0.004) ¢/kWh; and no charge for NS, Outdoor Lighting, and Traffic Lighting. It is reasonable and appropriate for Rider CE to become effective for usage on and after January 1, 2016.

13. DNCP requested the recovery of NLR in the amount of $37,028 and PPI in the amount of $108,514 for the test period, and projected PPI of $158,847 but no NLR for the rate

period. DNCP's calculation and proposed recovery of NLR and a PPI is consistent with the Revised Mechanism, and is appropriate for recovery in this proceeding.

14. The jurisdictional and customer class cost allocations and assignments for Rider C and Rider CE included in Company Rebuttal Exhibit TPS-1 are acceptable for purposes of this proceeding and are consistent with the Revised Mechanism.

15. DNCP satisfactorily explained its consumer education and awareness activities and the volume of activity associated with such initiatives during the test period, as directed by the Commission in the 2014 DSM/EE cost and incentive recovery order in Docket No. E-22, Sub 513 (2014 Order). It is appropriate for DNCP to continue to provide such information to the Commission in future rider proceedings.

16. The evaluation, measurement, and verification (EM&V) analyses and reports prepared by DNCP are reasonable for purposes of this proceeding. The EM&V data provided by DNCP and reviewed by the Public Staff for vintage year 2014 and earlier vintages have appropriately been incorporated into the DSM/EE rider calculations.

17. It is reasonable for DNCP to include an ongoing chronology of changes to program attributes, including but not limited to, the initial estimates used, any changes to the initial estimates, when those changes take effect, and the source data related to the change. It is appropriate for the Company and Public Staff to work together to determine how to incorporate this information in future EM&V reports.

18. The Total Resource Cost (TRC) cost effectiveness test results for the Residential Home Energy Check-Up and Residential Heat Pump Tune-Up program have been below 1.0 in recent years. The TRC results are projected to remain below 1.0 in future years for the Residential Heat Pump Tune-Up program, and are projected to be 1.07 for the Residential Home Energy Check-Up program. However, these programs are part of a residential "bundle" of programs where customer participation in one program can lead to participation in other programs, and the bundle of four residential programs is projected to have a going forward TRC of 1.01. Based on DNCP's projected TRC for the residential program bundle, the Company's plans to bring new residential EE programs to North Carolina by 2017, and recognizing the Company's commitment to discuss with the Public Staff how to improve cost effectiveness, the Commission finds it reasonable to allow the Residential Home Energy Check-Up and Residential Heat Pump Tune-Up programs to continue as approved EE programs through December 31, 2016.

19. There is considerable potential for EE savings through residential lighting, and DNCP should pursue a residential lighting program or lighting measures as a component of a new residential EE program as soon as it is feasible.

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

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted. The rate period and test period used by DNCP are consistent with Commission Rule R8-69.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

The evidence for these findings of fact is contained in DNCP's Application; the direct testimony and exhibits of DNCP witnesses Hubbard, Newcomb, Turner, and Givens; the supplemental testimony and exhibits of the Company's witnesses; the rebuttal testimony and exhibits of the Company's witnesses; the testimony of Public Staff witness Floyd; and the affidavit of Public Staff witness Maness.

In its Application, the Company requested approval of rate period cost and (as applicable) utility incentive recovery for its: (a) Phase I Air Conditioner Cycling Program; (b) Phase II DSM/EE programs: Non-residential Energy Audit Program, Non-residential Duct Testing & Sealing Program, Residential Home Energy Check-Up Program, Residential Duct Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program; (c) Phase III DSM/EE programs: Non-residential Lighting Systems & Controls Program, Non-residential Heating & Cooling Efficiency Program, and Non-residential Window Film Program; (d) 2015 North Carolina-only Low Income Program; and (e) Phase IV: Income and Age Qualifying Home Improvement Program.

DNCP witness Hubbard discussed the history of Commission approvals for the Company's DSM/EE programs. At the time his direct testimony was filed, witness Hubbard stated that DNCP also had a pending request for approval of the Phase IV Income and Age Qualifying Home Improvement Program. Subsequently, on October 6, 2015, the Commission issued its Order approving that program in Docket No. E-22, Sub 523. As a result, all the programs and proposed programs identified in the Company's Application and direct testimony are now eligible for cost and utility incentive recovery.

In his testimony, Public Staff witness Floyd affirmed that the programs listed by DNCP are eligible for cost and/or utility incentive recovery in the present proceeding under G.S. 62-133.9, subject to certain program-specific conditions imposed by the Commission regarding the recovery of NLR and PPI. He further noted that in addition to the active programs listed above, DNCP previously operated Residential Lighting, Commercial Lighting, and Commercial HVAC programs, all of which are now canceled. Witness Floyd additionally testified that because the costs and NLR of canceled programs are still being trued up, and the PPIs of those programs are to be amortized over a period of years, some of those items are appropriate for recovery in the DSM/EE and DSM/EE EMF riders being established in the present case.

Company witness Turner provided the projected system-wide estimated DSM/EE program and common costs for the rate period and the actually incurred program and common costs for the test period. According to witness Turner, "program costs" are costs directly attributable to individual programs, while "common costs" are part of the overall effort of implementing the DSM/EE programs, but not directly associated with any individual program. Company witnesses Turner and Stuller provided the amounts of common costs applicable to this proceeding, as well as the allocation of those costs to specific DSM/EE programs.

Company witness Turner also provided PPI calculations for the rate period and for the test period. With regard to the estimated PPI calculations for the rate period, witness Turner utilized a simplified, conservative approach based on already determined PPI results in past proceedings and estimated DSM/EE costs for the rate period, consistent with the Revised Mechanism.

Company witness Newcomb presented testimony and exhibits setting forth the Company's estimated Utility Cost Test (UCT) and TRC test results for vintage year 2016 for all open DSM and EE programs. Witness Newcomb discussed his calculations of cost effectiveness, and observed that vintage year 2016 TRC cost effectiveness results for the Residential Home Energy Check-Up and Residential Heat Pump Tune-Up programs were lower than 1.0.[1] He testified that DNCP would not be seeking PPI for those two programs.

Company witness Givens presented the calculation of NLR for the test period, based on the Company's calculations of North Carolina retail sales lost due to DSM/EE, and the applicable billing rates for each program. Additionally, Company witness Hubbard testified that DNCP has not projected NLR for the rate period, consistent with its approach in the 2014 DSM/EE cost recovery rider. Witness Hubbard proposed to true-up NLR in future proceedings. He further stated that the Company had not identified any found revenues during the test period nor has it identified any projected found revenues during the rate period.

Public Staff witness Maness testified that based on its investigation, the Public Staff concluded that with the incorporation of the Public Staff's recommended adjustment to carrying costs (and interest on the EMF refund), the Company will have calculated the DSM/EE and DSM/EE EMF revenue requirements, and the resulting Riders C and CE, in a manner consistent with the Revised Mechanism, as well as in accordance with G.S. 62-133.9, Commission Rule R8-69, and prior Commission orders related to DSM/EE matters. The exception noted by witness Maness was corrected by the Company in its rebuttal testimony and exhibits.

Therefore, consistent with the Commission's previous orders approving DNCP's DSM/EE programs and the evidence in this proceeding, the Commission finds and concludes that DNCP should be allowed to recover the appropriate and reasonable projected rate period and actual test period costs and utility incentives associated with offering each of its former, ongoing, and newly approved programs as described in this proceeding. The Commission also finds and concludes that the recovery of program costs, common costs, NLR, and PPI is consistent with the Revised Mechanism approved by the Commission. Further, the Commission finds and concludes that DNCP's request to true-up NLR in Rider CE in future proceedings is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-14

The evidence for these findings of fact is contained in the Company's Application; the direct testimony and exhibits of DNCP witnesses Hubbard, Newcomb, Turner, Givens, Stuller, and Stephens; the supplemental testimony and exhibits of witnesses Turner, Givens, Stuller, and Stephens; the rebuttal testimony and exhibit of witness Givens and the rebuttal exhibits of witnesses Stuller and Stephens; and the affidavit and exhibits of Public Staff witness Maness.

[1] Company Exhibit RCN-1, Schedule 4 and Corrected Schedule 4.

Company witness Turner presented testimony supporting the system-level program operations and maintenance (O&M) costs for each program and common costs projected for calendar year 2016 (the rate period), as well as the actual system-level program O&M costs for the July-December 2014 test period. The total amount of system-level projected rate period program and common O&M costs are $50,717,132 (Supplemental Exhibit DLT-1, Schedule 1, Page 1), and the total amount of system-level actual test period program and common O&M costs are $25,419,069 (Supplemental Exhibit DLT-1, Schedule 7).

Witness Turner also calculated the projected rate year and actual vintage year 2014 proposed North Carolina retail PPI for each program. His Company Exhibit DLT-1, Schedule 6, and Company Supplemental Exhibit DLT-1, Schedule 6, provide the calculations for the PPI EMF true-up associated with vintage year 2014 for each program. He further states that these results are combined with the amortization of prior vintage year results in the exhibits of Company witness Givens to produce the total test year PPI. Witness Turner's Company Supplemental Exhibit DLT-1, Schedule 5, provides the total calculations for the projected rate period PPI. DNCP witness Turner explained in his direct testimony that the Schedule 5 rate period PPI was calculated in two parts: (1) for measurement units installed in 2014 and earlier vintage years, the "actual" results were used to estimate rate period PPI, consistent with the methodology in past cases, and (2) for measurement units to be installed in 2016, witness Turner used a simplified and conservative estimation of PPI, calculated as 1% of the current case's operating revenue requirement. Witness Turner stated in his supplemental testimony that he calculated DNCP's projected rate period PPI of $158,847 for the DSM/EE programs in accordance with the Revised Mechanism. In addition, he calculated a vintage 2014 PPI amount of $35,281, to be trued up in the DSM/EE EMF.

In his direct testimony, Company witness Givens testified that he used witness Turner's projected DSM/EE O&M costs and PPI, as well as calculations of capital costs, depreciation and return to calculate the rate period revenue requirement for Rider C. DNCP witness Givens stated that throughout his calculations he used jurisdictional allocation factors provided by witness Stuller to determine North Carolina retail revenue requirements, when necessary. His Rider C revenue requirement includes the following cost components: (1) operating expenses (including common costs) projected to be incurred during the rate period; (2) capital costs (including related depreciation expense) projected to be incurred during the rate period; and (3) a PPI projected for the rate period. Witness Givens noted that DNCP is omitting any projection of NLR for the rate period.

In his supplemental testimony, on Supplemental Exhibit CAG-1, Schedule 1, witness Givens calculated DNCP's requested North Carolina retail rate period (January 1, 2016, through December 31, 2016) projected revenue requirement as follows:

1.	Operating Expense	$3,085,917
2.	Capital Costs	158,967
3.	NLR	0
4.	PPI	158,847
5.	Total	$3,403,731

Witness Givens' supplemental testimony accepted two corrections affecting the Rider C revenue requirement after discussions with the Public Staff. DNCP witness Givens testified that the corrections to the Rider C revenue requirement included the following: (1) the projected Air Conditioning Cycling program capital spend amounts in 2016 were updated as supported in Company Witness Turner's Supplemental Exhibit DLT-1, Schedule 1; and (2) the projected PPI calculation for the Air Conditioning Cycling program was updated as reflected in Company Witness Turner's Supplemental Filing Exhibit DLT-1, Schedule 5.

Witness Givens stated that he also calculated DNCP's DSM/EE EMF revenue requirement, which includes actual costs (both capital and operation and maintenance components), a PPI, and actual NLR for the DSM/EE EMF test period, offset by revenues collected during that period. Witness Givens calculated NLR by use of lost kWh sales calculated by Company witness Newcomb and NLR rates calculated by Company witness Stephens. The DSM/EE EMF revenue requirement, as updated in witness Givens' rebuttal testimony is a refund of ($91,603), which includes interest of 10% on the over-recovery amount. Witness Givens' supplemental testimony accepted five corrections affecting the Rider CE revenue requirement, made following discussions with the Public Staff. Additionally, witness Givens' rebuttal testimony accepted, for purposes of the instant proceeding, two adjustments affecting the Rider CE revenue requirement, as recommended by the Public Staff. The DSM/EE revenue requirement, as set forth in witness Givens rebuttal exhibits, is made up of the following components:

Operating expenses	$1,502,216
Capital costs	48,742
NLR	37,028
PPI	108,514
Test period Rider C revenues	(1,785,494)
Net revenue requirement subtotal	(88,994)
Carrying costs	1,753
Interest on EMF refund	(4,362)
Total Rider CE revenue requirement	$(91,603)

Company witness Stuller testified in his direct testimony that his determination of the jurisdictional and customer class responsibility for DSM/EE costs was consistent with the Revised Mechanism and was the same method approved by the Commission in last year's DSM/EE cost recovery proceeding (Docket No. E-22, Sub 513). Witness Stuller testified that he allocated common costs to the DSM/EE programs, allocated program costs to the North Carolina retail jurisdiction, and then assigned residential program costs to the residential class and allocated non-residential program costs to the appropriate non-residential customer classes. He stated he adjusted the allocation factors for the non-residential revenue requirements so that costs would not be allocated to customers who opted out of the DSM/EE rider pursuant to G.S. 62-133.9(f). He noted that no costs were allocated to the Street and Outdoor Lighting class and the Traffic Lighting class, as DSM/EE programs do not directly benefit customers in those classes.

Witness Stuller's revised exhibits, and supplemental and rebuttal testimony and exhibits, presented revised jurisdictional and customer class cost allocations for Rider C and Rider CE as proposed for the rate period. The revisions were based on the updated revenue requirements provided in the supplemental and rebuttal testimony and exhibits of DNCP witness Givens, as well as a correction to the allocation of common costs as noted in witness Stuller's supplemental testimony. As shown on witness Stuller's Company Rebuttal Exhibit No. TPS-1, Schedule 3, Pages 2 and 4, the North Carolina retail jurisdictional rate period revenue requirement was assigned or allocated to the classes as follows:

Rate Class	Rider C Amount	Rider CE Amount
Residential	$2,204,729	$(49,860)
SGS Co & Muni	$777,617	$(27,073)
LGS	$265,757	$(9,252)
6VP	$155,627	$(5,418)
NS	$0	$0
ST & Outdoor Lighting	$0	$0
Traffic Lighting	$0	$0

Based on the above cost allocations to customer classes, Company witness Stephens discussed how she calculated the Rider C and Rider CE rates proposed for the rate period. Witness Stephens stated in her direct testimony that she determined the North Carolina forecasted net kWh sales for the rate period by revenue class, and further allocated those forecasted sales down to customer classes, less the kWh sales for customers who have opted out of the DSM/EE rider. Witness Stephens testified that she then divided the customer class revenue requirements by customer class forecasted kWh sales to calculate Rider C.

Further, witness Stephens testified that she used the same method to calculate Rider CE.

The kWh sales calculated by witness Stephens to determine the Rider C and CE billing factors, as reflected in her supplemental and rebuttal exhibits, are as follows:

Customer Class	Forecasted kWh Sales
Residential	1,628,311,783
Small General Service & Public Authority	823,345,191
Large General Service	289,503,753
6VP	140,887,744
NS	0
Outdoor Lighting	24,953,523
Traffic Lighting	546,450
Total	2,907,548,444

In her direct testimony, Company witness Stephens stated that to determine NLR for the test period, she first calculated the monthly non-fuel average base rates for each program for the test period, and then witness Givens applied those rates to the test period kWh reductions that were provided to him by witness Newcomb.

The customer class billing factors as revised in the Company's supplemental and rebuttal testimony would result in Rider C and Rider CE rates higher than stated in the public notice for this proceeding. Accordingly, witness Stephens in supplemental testimony and witness Givens in supplemental and rebuttal testimony proposed to adjust the Rider C rates so that the total of Rider C and Rider CE would be no more than the noticed amount. As noted by Public Staff witness Maness, the Rider C factors will be trued up in future proceedings so the Company will ultimately recover its actual reasonable and prudent costs and utility incentives.

Both witness Stephens' Company Rebuttal Exhibit DAS-1, Schedule 1, page 10, and the rebuttal testimony of witness Givens support the following customer class Rider C and Rider CE billing factors (including Regulatory Fee) to be put into effect on January 1, 2016:

CUSTOMER CLASS	RIDER C RATE NOTICED AMT. (cents/kWh)	RIDER CE RATE (cents/kWh)
Residential	0.130	(0.003)
Small General Service & Public Authority	0.090	(0.003)
Large General Service	0.087	(0.003)
6VP	0.106	(0.004)
NS	0.000	0.000
Outdoor Lighting	0.000	0.000
Traffic Lighting	0.000	0.000

Public Staff witness Maness stated that the Public Staff investigation revealed certain relatively minor issues and adjustments, which were incorporated into the Company's supplemental testimony along with some corrections discovered by the Company. He also noted one more adjustment that was discovered after DNCP filed its supplemental testimony. That adjustment concerns the appropriate calculation of carrying costs pursuant to Commission Rule R8-69(b)(6) and (c)(3). It was incorporated into the Company's rebuttal testimony. With that adjustment, witness Maness testified that DNCP's calculation of the DSM/EE and DSM/EE EMF revenue requirements and Rider C and Rider CE are consistent with the Revised Mechanism, G.S. 62-133.9, and Commission Rule R8-69. The DSM/EE and DSM/EE EMF revenue requirements presented on Maness Exhibit II, Schedule 2, (excluding Regulatory Fee) support the amounts presented by the Company in its rebuttal. Likewise, the Rider C and Rider CE rates presented in Maness Exhibit II, Schedule 1, support the rates requested by the Company in its rebuttal.

Based upon all of the evidence presented above and the entire record in this proceeding, the Commission finds and concludes that the DSM/EE EMF revenue requirement and proposed Rider CE billing factors to be charged during the rate period, as proposed in DNCP's supplemental and rebuttal filings, are appropriate. The Commission also finds and concludes that the projected DSM/EE rate period revenue requirement and Rider C billing factors to be charged during the rate period, as proposed in DNCP's supplemental and rebuttal filings, are appropriate. With regard to the requested recovery of NLR and PPI, the Commission finds and concludes that the amounts are appropriate for recovery in this proceeding and are calculated in a manner consistent with the

Revised Mechanism. The Commission further concludes that the jurisdictional and customer class cost allocations and assignments for Rider C and Rider CE included in Company Rebuttal Exhibit TPS-1 are acceptable for purposes of this proceeding and are consistent with the Revised Mechanism.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is contained in the direct testimony of DNCP witness Turner.

In response to Ordering Paragraph No. 5 of the Commission's 2013 Cost Recovery Order, DNCP witness Turner provided information on consumer education and awareness initiatives and event sponsorships conducted by VEPCO's Energy Conservation (EC) department during the test period. He explained that most of the Company's communication and outreach activities are tied directly to specific DSM/EE programs, so actual costs for general education and awareness are limited. He testified that during the test period, the EC department exhibited or spoke at approximately five events across the VEPCO service territory and hosted a contractor engagement event at Nags Head in November 2014. DNCP witness Turner further elaborated that the EC department relies heavily on online tools for general education, their web pages received around 70,000 visits in the test period, and the web pages for their contractor Honeywell also received over 16,000 visits.

The Public Staff did not oppose DNCP's consumer education and awareness activities or costs.

Based on the evidence presented above and the record, the Commission finds and concludes that DNCP's consumer education and awareness activities and costs are reasonable for purposes of this proceeding. Further, the Commission finds and concludes that the Company shall continue to include a list of consumer education and awareness activities and the volume of activity associated with each during the test period in its annual DSM/EE cost and incentive recovery filing.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-17

The evidence for these findings of fact is contained in the direct testimony of DNCP witness Hubbard, the direct and rebuttal testimony of witness Newcomb, and the testimony of Public Staff witness Floyd.

Witness Floyd testified that he had reviewed DNCP's 2015 EM&V report with the assistance of GDS Associates. He stated that he was of the opinion that the 2015 EM&V report complied with previous Commission orders pertaining to EM&V. He testified that DNCP is appropriately incorporating the results of its EM&V efforts into the DSM/EE rider calculations.

Public Staff witness Floyd discussed the details contained in the 2015 E&MV reports that he reviewed. Witness Floyd testified that more specific information regarding the actual activities or work being done would be beneficial and provide greater clarity on the application of specific

EM&V attributes, particularly when those attributes are modified. For example, when initial estimates of free ridership are adjusted to reflect actual results going forward, the tables showing program participation and savings would be more informative if those tables also identified the change, when the change became effective, and how the change affects participation and/or savings, or both. As a result, witness Floyd recommended that future EM&V reports should contain an ongoing chronology of changes to program attributes, including, but not limited to, the initial estimates used, any changes to the initial estimates, when those changes take effect, and the source data related to the change.

DNCP witness Newcomb stated that the Company plans to continue to file its annual EM&V report on April 1 of each year. He testified in his rebuttal testimony that the Company will work with its EM&V vendor and the Public Staff to determine how to incorporate the Public Staff's recommendation into future EM&V reports.

Based on the foregoing, the Commission finds and concludes that the EM&V analyses and reports prepared by DNCP are reasonable for purposes of this proceeding. Further, the Commission finds and concludes that the EM&V recommendation contained in the testimony of Public Staff witness Floyd is reasonable and should be incorporated in future EM&V reports. Additionally, the Commission finds that it is appropriate for the Company and the Public Staff to work together to determine how to incorporate the Public Staff's recommendation with regard to future EM&V reports.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding is contained in the testimony and exhibits of DNCP witness Newcomb, in the testimony of DNCP witness Hubbard, and in the testimony of Public Staff witness Floyd.

Public Staff witness Floyd expressed concern about the TRC scores below 1.0 for recent vintage years of both the Residential Home Energy Check-Up and Residential Heat Pump Tune-Up EE programs. Witness Newcomb's Company Exhibit RCN-1, Corrected Schedule 2, shows 2016 vintage year TRC cost effectiveness test results of 0.84 for the Residential Home Energy Check-Up program and 0.46 for the Residential Heat Pump Tune-Up program. His Exhibit RCN-1, Corrected Schedule 4, shows long-term projected TRC scores of 1.07 and 0.57, respectively, for the Residential Home Energy Check-Up and Residential Heat Pump Tune-Up programs. Public Staff witness Floyd recommended that, in general, programs should be canceled if they had a TRC below 1.0 for three years, and also that long-term projections of TRC results were an important assessment tool when determining program viability. Witness Floyd recommended that the Commission require DNCP to file program modifications that would raise the TRC scores above 1.0 for the Residential Home Energy Check-Up and Residential Heat Pump Tune-Up programs if the programs are to continue, and to do so by May 1, 2016.

In rebuttal testimony, DNCP witnesses Hubbard and Newcomb observed that these programs are part of a residential bundle of programs in which customer participation in one program often promotes participation in the other programs in the bundle. Witness Newcomb testified that under current planning assumptions the combined TRC for the residential bundle of program was projected to be 1.01 on a going-forward basis. Witnesses Hubbard and Newcomb both noted that the Residential Home Energy Check-Up and Residential Heat Pump Tune-Up programs are scheduled to expire in the Virginia jurisdiction in early 2017, so the Company, operating as Dominion Virginia Power, plans to file new, modified, or replacement programs in Virginia in 2016. If the programs are approved in Virginia, DNCP intends to file for approval of corresponding new programs in North Carolina in 2017. Witnesses Hubbard and Newcomb testified that the Public Staff agrees with this approach.

Based on the foregoing, the Commission concludes that DNCP should continue to discuss the cost effectiveness of the Residential Home Energy Check-Up and Residential Heat Pump Tune-Up programs with the Public Staff, and that it is reasonable and appropriate for the Company to continue to offer these EE programs in North Carolina through the end of calendar year 2016.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence for this finding is contained in the testimony of DNCP witness Hubbard and Public Staff witness Floyd.

Witness Floyd testified that the DNCP Residential Lighting program expired in 2011 and has not been replaced. He noted that the Company obtains an atypically low percentage of its EE savings from lighting measures, and the Company's EE market potential study indicated there is a significant amount of residential EE potential from LED upgrades over the next ten years. He recommended that DNCP continue its work toward developing new residential lighting EE measures and programs, and that it seek regulatory approvals as soon as possible. He further recommended that the Company should implement a North Carolina-only residential EE lighting program if it could not get a system-wide program approved.

In rebuttal testimony, witness Hubbard agreed that there is an energy saving potential that remains to be realized through a residential lighting program. He noted that system-wide programs provide cost savings, so the Company proposed to work with vendors to develop a residential EE program with several lighting options, seek approval of such a program in Virginia, and then bring it to North Carolina.

Therefore, based on the above testimony and the evidence in the record, the Commission finds and concludes that DNCP should seek proposals from vendors for a system-wide residential EE program with several lighting options, as described by witness Hubbard. If that is not successful, the Company should determine if a North Carolina-only residential lighting program or measures would be cost effective, and should implement such a program or measures if cost effective. The Company should take these actions as expeditiously as possible.

IT IS, THEREFORE, ORDERED as follows:

1. That the appropriate annual DSM/EE rider, Rider C, to become effective on and after January 1, 2016, consists of the following customer class billing factor increments (including Regulatory Fee): Residential – 0.130 ¢/kWh; Small General Service and Public Authority – 0.090

¢/kWh; Large General Service – 0.087 ¢/kWh; 6VP – 0.106 ¢/kWh; and no charge for NS, Outdoor Lighting, and Traffic Lighting.

2. That the appropriate annual DSM/EE EMF rider, Rider CE, to become effective on and after January 1, 2016, consists of the following customer class billing factor decrements (including Regulatory Fee): Residential – (0.003) ¢/kWh; Small General Service and Public Authority – (0.003) ¢/kWh; Large General Service -- (0.003) ¢/kWh; 6VP – (0.004) ¢/kWh; and no decrement for NS, Outdoor Lighting, and Traffic Lighting.

3. That DNCP shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket Nos. E-22, Subs 525 and 526, and the Company shall file such notice for Commission approval as soon as practicable, but not later than three working days after the Commission issues the last of its orders in the above-referenced dockets.

4. That DNCP shall file appropriate rate schedules and riders with the Commission to implement the provisions of this Order as soon as practicable.

5. That DNCP shall continue to provide a listing of the Company's event sponsorship and consumer education and awareness initiatives during the test period in future DSM/EE rider proceedings.

6. That DNCP shall assess ways to improve the TRC cost effectiveness scores for the Residential Home Energy Check-Up and Residential Heat Pump Tune-Up programs; work with the Public Staff to analyze the contributions of these programs to the cost effectiveness and participation rates of the residential bundle of programs; and modify or replace these programs after December 31, 2016, if they are not projected to be cost effective under the Revised Mechanism.

7. That DNCP shall work with the Public Staff to incorporate the Public Staff's recommendation for a chronology of changes to program attributes in future EM&V reports.

8. That DNCP shall determine whether a residential lighting program or lighting measures as a component of a new residential EE program would be cost effective and, if so, shall develop such program or measures as soon as feasible.

ISSUED BY ORDER OF THE COMMISSION.
This the _14th___day of December, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

Commissioner Susan W. Rabon did not participate in this decision.

DOCKET NO. E-7, SUB 1073

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	)))))	ORDER APPROVING DSM/EE RIDER AND REQUIRING FILING OF PROPOSED CUSTOMER NOTICE

HEARD: Tuesday, June 2, 2015, at 9:40 a.m., and Tuesday, July 7, 2015, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chairman Edward S. Finley, Jr.; Commissioners Bryan E. Beatty; Don M. Bailey; Jerry C. Dockham; and James G. Patterson

APPEARANCES:

For Duke Energy Carolinas, LLC:

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For North Carolina Sustainable Energy Association:

Peter Ledford, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Carolina Industrial Group for Fair Utility Rates III:

Adam Olls, Bailey & Dixon, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27601

For Southern Alliance for Clean Energy:

Gudrun Thompson, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

Lucy E. Edmondson, Staff Attorney, Public Staff – North Carolina Utilities Commission, 430 North Salisbury Street, Raleigh, North Carolina 27603

BY THE COMMISSION: General Statute 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric public utilities, outside of a general rate case, for recovery of all reasonable and prudent costs incurred for adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) measures. The Commission is also authorized to award incentives to electric companies for adopting and implementing new DSM/EE measures, including, but not limited to, appropriate rewards based on (1) the sharing of savings achieved by the DSM and EE measures and/or (2) the capitalization of a percentage of avoided costs achieved by the measures. Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric public utility to establish an annual DSM/EE rider to recover the reasonable and prudent costs incurred for adopting and implementing new DSM/EE measures previously approved by the Commission pursuant to Commission Rule R8-68. Further, Commission Rule R8-69(b) provides for the establishment of a DSM/EE experience modification factor (EMF) rider to allow the electric public utility to collect the difference between reasonable and prudently incurred costs and the revenues that were actually realized during the test period under the DSM/EE rider then in effect. Commission Rule R8-69(c) permits the utility to request the inclusion of utility incentives (the rewards authorized by the statute), including net lost revenues (NLR), in the DSM/EE rider and the DSM/EE EMF rider.

In the present proceeding, Docket No. E-7, Sub 1073, on March 4, 2015, Duke Energy Carolinas, LLC (DEC or the Company), filed an application for approval of its DSM/EE rider (Rider EE[1] or Rider 7) for 2016[2] (Application) and the direct testimony and exhibits of Carolyn T. Miller, Rates Manager for DEC; Conitsha B. Barnes, Strategy and Collaboration Manager for the Company's Market Solutions Regulatory Strategy and Evaluation group; and Roshena M. Ham, Manager, Measurement and Verification for DEC.

On March 16, 2015, DEC filed an Amended Application along with the corrected testimony and exhibits of witness Miller.

On March 18, 2015, the Commission issued an Order scheduling a hearing for June 2, 2015, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice.

[1] DEC refers to its DSM/EE Rider as "Rider EE"; however, this rider includes charges intended to recover both DSM and EE revenue requirements.

[2] The Rider EE proposed in this proceeding is the Company's seventh Rider EE and includes components that relate to Vintages 1, 2, 3, and 4 of the cost recovery mechanism approved in Docket No. E-7, Sub 831, and components that relate to Vintages 2014, 2015, and 2016 of the cost recovery mechanism approved in Docket No. E-7, Sub 1032. For purposes of clarity, the aggregate rider is referred to in this Order as "Rider 7" or the proposed "Rider EE." Rider 7 is proposed to be effective for the rate period January 1, 2016, through December 31, 2016.

The intervention of the Public Staff – North Carolina Utilities Commission (Public Staff) has been recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On March 17, 2015, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was granted on March 24, 2015. On March 23, 2015, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted on March 24, 2015. The Carolina Industrial Group for Fair Utility Rates III filed a petition to intervene on May 18, 2015, which was granted on May 21, 2015. On May 18, 2015, the Southern Alliance for Clean Energy (SACE) filed a petition to intervene, which was granted on May 21, 2015.

On May 15, 2015, DEC filed the supplemental direct testimony and exhibits of witness Miller and the supplemental exhibits of witness Barnes. Also on May 15, 2015, DEC filed a motion requesting that the Commission schedule an additional public hearing and require public notice based on the revised proposed rates included in DEC's supplemental testimony.

On May 18, 2015, the Public Staff filed a motion for extension of time. On that same date, the Commission issued an Order Granting Motion for Extension of Time to File Intervenor and Rebuttal Testimony.

On May 20, 2015, SACE filed the testimony of Taylor Allred, its Energy Policy Manager; and the Public Staff filed the affidavits of Michael C. Maness, Assistant Director of the Accounting Division, and Jack L. Floyd, Engineer in the Electric Division.

On May 22, 2015, DEC, SACE, and the Public Staff filed a joint motion to excuse their witnesses from appearing at the June 2, 2015 evidentiary hearing. On May 28, 2015, the Commission issued an Order Granting Motion to Excuse Witnesses from Attending Hearing.

On May 28, 2015, the Commission issued an Order scheduling an additional public hearing in this matter for July 7, 2015, and requiring DEC to publish public notice of the hearing.

The case came on for hearing as scheduled on June 2, 2015. No public witnesses appeared at the hearing. All pre-filed testimony, exhibits and affidavits of the parties were accepted into evidence by the Commission.

On July 7, 2015, the additional public hearing was held as scheduled in Raleigh, North Carolina. No public witnesses appeared at the hearing. Also, on July 7, 2015, the Public Staff filed a motion requesting that the date for the filing of proposed orders and briefs be extended to July 17, 2015. On July 8, 2015, the Commission issued an Order granting the extension of time requested by the Public Staff.

On July 17, 2015, DEC and the Public Staff filed a Joint Proposed Order. On that same date, SACE filed a Post-Hearing Brief and NCSEA filed a Post-Hearing Letter.

Other Pertinent Proceedings: Docket No. E-7, Subs 831, 938, 979, and 1032

On February 9, 2010, the Commission issued an Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues in DEC's first DSM/EE rider proceeding, Docket No. E-7, Sub 831 (Sub 831 Order). In the Sub 831 Order, the Commission approved, with certain modifications, the Agreement and Joint Stipulation of Settlement between DEC, the Public Staff, SACE, Environmental Defense Fund, the Natural Resources Defense Council, and the Southern Environmental Law Center (Sub 831 Settlement), which described the modified save-a-watt mechanism (Sub 831 Mechanism), pursuant to which DEC calculated, for the period from June 1, 2009 until December 31, 2013, the revenue requirements underlying its DSM/EE riders based on percentages of avoided costs, plus compensation for NLR resulting from EE programs only. The Sub 831 Mechanism was approved as a pilot with a term of four years, ending on December 31, 2013.

On February 15, 2010, the Company filed an Application for Waiver of Commission Rule R8-69(a)(4) and R8-69(a)(5) in Docket No. E-7, Sub 938 (Sub 938 Waiver Application), requesting waiver of the definitions of rate period and test period. Under the Sub 831 Mechanism, customer participation in the Company's DSM and EE programs and corresponding responsibility to pay Rider EE are determined on a vintage year basis. A vintage year is generally the 12-month period in which a specific DSM or EE measure is installed for an individual participant or group of participants.[1] For purposes of the modified save-a-watt portfolio of programs, the Company applied the vintage year concept on a calendar-year basis for administrative ease for the Company and its customers. Pursuant to the Sub 938 Waiver Application, test period is defined as the most recently completed vintage year at the time of the Company's DSM/EE rider application filing date.[2]

On February 24, 2010, in Docket No. E-7, Sub 938, the Commission issued an Order Requesting Comments on the Company's Sub 938 Waiver Application. After receiving comments and reply comments, the Commission entered an Order Granting Waiver, in Part, and Denying Waiver, in Part (Sub 938 Waiver Order) on April 6, 2010. In this Order, the Commission approved the requested waiver of R8-69(d)(3) in part, but denied the Company's requested waiver of the definitions of rate period and test period.

On May 6, 2010, DEC filed a Motion for Clarification or, in the Alternative, for Reconsideration, asking that the Commission reconsider its denial of the waiver of the definitions of test period and rate period, and that the Commission clarify that the EMF may incorporate

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[1] Vintage 1 is an exception in terms of length. Vintage 1 is a 19-month period beginning June 1, 2009 and ending December 31, 2010, as a result of the approval of DSM/EE programs prior to the approval of the cost recovery mechanism.

[2] Further, in the Sub 938 Second Waiver Order issued June 3, 2010, the Commission concluded that DEC should true up all costs during the save-a-watt pilot through the EMF rider provided in Commission Rule R8-69(b)(1). The modified save-a-watt approach approved in the Sub 831 Order required a final calculation after the completion of the four-year program, comparing the cumulative revenues collected related to all four vintage years to amounts due the Company, taking into consideration the applicable earnings cap.

adjustments for multiple test periods. In response, the Commission issued an Order on Motions for Reconsideration on June 3, 2010 (Sub 938 Second Waiver Order), granting DEC's Motion. The Sub 938 Second Waiver Order established that the rate period for Rider EE would align with the 12-month calendar year vintage concept utilized in the Commission-approved save-a-watt approach (in effect, the calendar year following the Commission's order in each annual DSM/EE cost recovery proceeding), and that the test period for Rider EE would be the most recently completed vintage year at the time of the Company's Rider EE cost recovery application filing date.

Consistent with the Sub 938 Second Waiver Order, the Company calculated Rider EE for purposes of the present proceeding (Docket No. E-7, Sub 1073) using the rate period of January 1, 2016, through December 31, 2016. In addition, the present filing for Rider EE includes EMF components for Vintage 2014 because that vintage year (2014, also the test year in this proceeding) has been completed as of the filing date. DEC also included in the present filing adjustments to the EMF components for Vintages 1, 2, 3, and 4, as well as the final true-up of all four vintages under the Sub 831 Mechanism.

On February 8, 2011, in Docket No. E-7, Sub 831, the Commission issued its Order Adopting "Decision Tree" to Determine "Found Revenues" and Requiring Reporting in DSM/EE Cost Recovery Filings in Docket No. E-7, Sub 831 (Sub 831 Found Revenues Order), which included in the Order's Appendix A a "Decision Tree" to identify, categorize, and net possible found revenues against the NLR created by the Company's EE programs. Found revenues may result from activities that directly or indirectly result in an increase in customer demand or energy consumption within DEC's service territory.

On November 8, 2011, in Docket No. E-7, Sub 979, the Commission issued its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice (Sub 979 Order), in which it approved the Evaluation, Measurement, and Verification (EM&V) agreement (EM&V Agreement) reached by the Company, SACE, and the Public Staff. Pursuant to the EM&V Agreement, for all EE programs, with the exception of the Non-Residential Smart $aver® Custom Rebate Program and the Low Income Energy Efficiency and Weatherization Assistance Program, actual EM&V results are applied to replace all initial impact estimates back to the beginning of the program offering. For the purposes of the vintage true-ups, these initial EM&V results will be considered actual results for a program until the next EM&V results are received. The new EM&V results will then be considered actual results going forward and will be applied prospectively for the purposes of truing up vintages from the first day of the month immediately following the month in which the study participation sample for the EM&V was completed. These EM&V results will then continue to apply and be considered actual results until superseded by new EM&V results, if any. For all new programs and pilots, the Company will follow a consistent methodology, meaning that initial estimates of impacts will be used until DEC has valid EM&V results, which will then be applied back to the beginning of the offering and will be considered actual results until a second EM&V is performed.

On February 6, 2012, in the Sub 831 docket, the Company, SACE, and the Public Staff filed a proposal regarding revisions to the program flexibility requirements (Flexibility Guidelines). The proposal divided potential program changes into three categories based on the magnitude of the change, with the most significant changes requiring regulatory approval by the Commission prior to implementation; less extensive changes requiring advance notice prior to making such program changes; and minor changes being reported on a quarterly basis to the Commission. The Commission approved the joint proposal in its July 16, 2012 Order Adopting Program Flexibility Guidelines.

On October 29, 2013, the Commission issued its Order Approving DSM/EE Programs and Stipulation of Settlement in Docket No. E-7, Sub 1032 (Sub 1032 Order), which approved a new cost recovery and incentive mechanism for DSM and EE Programs (Sub 1032 Mechanism) and a portfolio of DSM/EE programs to be effective January 1, 2014, (Sub 1032 portfolio of programs) to replace the cost recovery mechanism and portfolio of DSM/EE programs approved in Docket No. E-7, Sub 831. In the Sub 1032 Order, the Commission approved an Agreement and Stipulation of Settlement, filed on August 19, 2013, and amended on September 23, 2013, by and between DEC; NCSEA; the Environmental Defense Fund; SACE; the South Carolina Coastal Conservation League; the Natural Resources Defense Council; the Sierra Club; and the Public Staff (Stipulating Parties), which incorporates the Sub 1032 Mechanism (Sub 1032 Settlement).

Under the Sub 1032 Settlement, as approved by the Commission, the portfolio of DSM and EE programs filed by the Company was approved with no specific duration (unlike the programs approved in Sub 831, which explicitly expired at December 31, 2013). Additionally, the Sub 1032 Settlement included a provision that the Company and Public Staff would study the issue of the appropriate avoided transmission and distribution (T&D) costs to be used in the Company's calculations of cost-effectiveness and, if appropriate, recommend in the Company's 2014 DSM/EE rider proceeding adjustments to the rate filed in the Sub 1032 proceeding, to be made on a prospective basis. The Stipulating Parties also agreed that the Company would meet with the North Carolina Waste Awareness and Reduction Network (NC WARN) and other interested intervenors to discuss the low-income program proposed by NC WARN. The Stipulating Parties further agreed to have discussion and consideration of on-bill repayment and combined heat and power (CHP) as part of the Company's EE Collaborative (Collaborative), and to report to the Commission the status and results of that discussion and consideration. Finally, the Sub 1032 Settlement also provided that the Company's annual DSM/EE rider would be determined according to the Sub 1032 Settlement and the terms and conditions set forth in the Sub 1032 Mechanism.

The overall purpose of the Sub 1032 Mechanism, as approved as part of the Sub 1032 Settlement, is to (1) allow DEC to recover all reasonable and prudent costs incurred for adopting and implementing new DSM and new EE measures; (2) establish certain requirements, in addition to those of Commission Rule R8-68, for requests by DEC for approval, monitoring, and management of DSM and EE programs; (3) establish the terms and conditions for the recovery of NLR (net of found revenues) and a Portfolio Performance Incentive (PPI) to reward DEC for adopting and implementing new DSM and EE measures and programs; and (4) provide for an additional incentive to further encourage kilowatt-hour (kWh) savings achievements. The Sub 1032 Mechanism also includes the following provisions, among several others: (a) it shall continue until terminated pursuant to Commission Order; (b) modifications to Commission-approved DSM/EE programs will be made using the Flexibility Guidelines; and (c) treatment of opted-out and opted-in customers will continue to be guided by the Commission's Orders in Docket No. E-7, Sub 938, with the addition of an additional opt-in period during the first week in March of each year.

Docket No. E-7, Sub 1073

Based upon consideration of DEC's Application, the pleadings, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. DEC is a public utility with a public service obligation to provide electric utility service to customers in its service area in North Carolina and is subject to the jurisdiction of the Commission.

2. The Commission has jurisdiction over this Application pursuant to the Public Utilities Act. A utility may petition the Commission for approval of an annual rider to recover all reasonable and prudent costs incurred for the adoption and implementation of new DSM and EE measures, as well as appropriate utility incentives, pursuant to G.S. 62-133.9 and Commission Rules R8-68 and R8-69. Based on the specific recovery of costs and incentives proposed by DEC in this proceeding, the Commission concludes that it has the authority to consider and approve the relief the Company is seeking in this docket.

3. For purposes of this proceeding, DEC has requested approval of costs and incentives related to the following DSM/EE programs to be included in Rider 7: Appliance Recycling Program; Energy Assessments Program; Energy Efficiency Education Program; Energy Efficient Appliances and Devices; HVAC Energy Efficiency Program; Multi-Family Energy Efficiency Program; My Home Energy Report; Income-Qualified Energy Efficiency and Weatherization Program; Residential Retrofit Pilot Program; Power Manager; Nonresidential Smart $aver® Energy Efficient Food Service Products Program; Nonresidential Smart $aver® Energy Efficient HVAC Products Program; Nonresidential Smart $aver® Energy Efficient IT Products Program; Nonresidential Smart $aver® Energy Efficient Lighting Products Program; Nonresidential Smart $aver® Energy Efficient Process Equipment Products Program; Nonresidential Smart $aver® Energy Efficient Pumps and Drives Products Program; Nonresidential Smart $aver® Custom Program; Nonresidential Smart $aver® Custom Energy Assessments Program; PowerShare®; PowerShare® Call Option; Energy Management and Information Services Pilot Program; Small Business Energy Saver; and Smart Energy in Offices.

4. For purposes of inclusion in Rider 7, the Company's portfolio of EE and DSM programs is cost-effective.

5. The EM&V analyses and reports prepared by DEC's independent third party evaluator are acceptable for purposes of this proceeding.

6. The Public Staff and DEC agreed to continue to discuss the EM&V information presented in Ham Exhibit B (Smart Energy Now Pilot)[1] and Ham Exhibit E (Energy Efficient Appliances and Devices Program [Specialty Bulb measures]), and further agreed that the vintages of these programs covered by these EM&V reports may be subject to further adjustment in next year's proceeding depending upon the outcome of these discussions. It is reasonable and appropriate to accept the impacts derived through the EM&V analyses for the Smart Energy Now Pilot and the Specialty Bulb measures of the Energy Efficient Appliances and Devices Program for purposes of this proceeding, subject to true-up in next year's proceeding.

7. The EM&V recommendations contained in the affidavit of Public Staff witness Floyd are appropriate for inclusion in future EM&V reports for the applicable EE programs, including certain program vintages that remain to be verified and trued up.

8. It is reasonable, for purposes of this proceeding, for DEC to include negative found revenues associated with its current initiative to replace mercury vapor (MV) lighting with light emitting diode (LED) fixtures in the calculation of net found revenues used in the Company's calculation of NLR.

9. Subject to future adjustments and true-ups to vintages of the programs covered by the EM&V filed in Ham Exhibits B and E in this proceeding, it is reasonable for the Company to make a modified save-a-watt earnings cap true-up in this proceeding. Further, the benefit to the customers of the avoided cost revenue requirement previously being set at 85% of the amount that could be justified should be allowed to offset the earnings cap for purposes of the calculation of interest.

10. Pursuant to the Commission's Sub 938 Second Waiver Order and the Sub 1032 Order, the rate period for purposes of this proceeding is January 1, 2016 through December 31, 2016.

11. Rider 7 includes EMF components for Vintage 2014 EE and DSM programs. Consistent with the Sub 938 Second Waiver Order, the test period for these EMF components is the period from January 1, 2014, through December 31, 2014 (Vintage 2014). Rider 7 also includes adjustments to the EMF components previously approved for Vintage Years 1, 2, 3, and 4, as well as the final true-up for those four vintages under the Sub 831 Mechanism.

12. DEC's proposed rates for Rider 7 are comprised of both prospective and EMF components. The prospective components include factors designed to collect program costs and the PPI for the Company's Vintage 2016 DSM and EE programs, as well as the first year of NLR for the Company's Vintage 2016 EE programs; the second year of NLR for Vintage 2015 EE programs; and the third year of NLR for Vintage 2014 EE programs. The EMF components include the true up of Vintage 2014 program costs and a partial true-up of Vintage 2014 NLR and PPI; factors designed to true up the recovery of revenue requirements related to Vintages 1, 2, 3, and 4;

[1] The Smart Energy Now Pilot program was approved on February 14, 2011, in Docket No. E-7, Sub 961. On August 13, 2014, the Commission approved a fully-commercialized version of the program, which is called Smart Energy in Offices.

and the final true-up of Vintages 1 through 4, as provided for in the Sub 831 Mechanism. DEC, as reflected in the supplemental testimony and exhibits of Company witness Miller and the supplemental exhibits of Company witness Barnes, has calculated the components of Rider 7 in a manner that appropriately reflects the Commission's findings and conclusions in this Order, as well as the Commission's findings and conclusions as set forth in the Sub 831 Order, the Sub 938 Waiver Order, the Sub 938 Second Waiver Order, the Found Revenues Order, the Sub 979 Order, and the Sub 1032 Order.

13. The reasonable and prudent Rider 7 billing factor for residential customers[1] is 0.3621 cents per kWh (including regulatory fee).

14. The reasonable and prudent Rider 7 Vintage 2016 EE prospective billing factor for non-residential customers who do not opt out of Vintage 2016 of the Company's EE programs is 0.2164 cents per kWh (including regulatory fee).

15. The reasonable and prudent Rider 7 Vintage 2016 DSM prospective billing factor for non-residential customers who do not opt out of Vintage 2016 of the Company's DSM programs is 0.0709 cents per kWh (including regulatory fee).

16. The reasonable and prudent Rider 7 Vintage 2015 prospective EE billing factor for non-residential customers who participated in Vintage 2015 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2015 during the annual enrollment period for that vintage, nor (b) opt out of Vintage 2016) is 0.0345 cents per kWh (including regulatory fee).

17. The reasonable and prudent Rider 7 Vintage 2014 prospective EE billing factor for non-residential customers who participated in Vintage 2014 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2014 during the annual enrollment period for that vintage, nor (b) opt out of Vintage 2016) is 0.0256 cents per kWh (including regulatory fee).

18. The reasonable and prudent Rider 7 Vintage 2014 EE EMF billing factor for non-residential customers who participated in Vintage 2014 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2014 during the annual enrollment period for that vintage, nor (b) opt out of Vintage 2016) is 0.0150 cents per kWh (including regulatory fee).

19. The reasonable and prudent Rider 7 Vintage 2014 DSM EMF billing factor for non-residential customers who participated in Vintage 2014 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2014 during the annual

[1] The residential billing factor applicable to all residential customers is the sum of the residential prospective and residential true-up factors for the applicable vintage years.

enrollment period for that vintage, nor (b) opt out of Vintage 2016) is (0.0044) cents per kWh (including regulatory fee).

20. The reasonable and prudent Rider 7 Vintage 4 EE EMF billing factor for non-residential customers who participated in Vintage 4 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 4 (2013) during the annual enrollment period for that vintage, nor (b) opt out of Vintage 2016) is 0.0326 cents per kWh (including regulatory fee).

21. The reasonable and prudent Rider 7 Vintage 4 DSM EMF billing factor for non-residential customers who participated in Vintage 4 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 4 (2013) during the annual enrollment period for that vintage, nor (b) opt out of Vintage 2016) is 0.0005 cents per kWh (including regulatory fee).

22. The reasonable and prudent Rider 7 Vintage 3 EE EMF billing factor for non-residential customers who participated in Vintage 3 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 3 (2012) during the annual enrollment periods for that vintage, nor (b) opt out of Vintage 2016) is 0.0261 cents per kWh (including regulatory fee).

23. The reasonable and prudent Rider 7 Vintage 3 DSM EMF billing factor associated with the true-up adjustment for non-residential customers who participated in Vintage 3 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 3 (2012) during the annual enrollment period for that vintage, nor (b) opt out of Vintage 2016) is (0.0017) cents per kWh (including regulatory fee).

24. The reasonable and prudent Rider 7 Vintage 2 EE EMF billing factor associated with the true-up adjustment for non-residential customers who participated in Vintage 2 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2 (2011) during the annual enrollment period for that vintage, nor (b) opt out of Vintage 2016) is 0.0148 cents per kWh (including regulatory fee).

25. The reasonable and prudent Rider 7 Vintage 2 DSM EMF billing factor associated with the true-up adjustment for non-residential customers who participated in Vintage 2 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2 (2011) during the annual enrollment period for that vintage, nor (b) opt out of Vintage 2016) is 0.0019 cents per kWh (including regulatory fee).

26. The reasonable and prudent Rider 7 Vintage 1 EE EMF billing factor associated with the true-up adjustment for non-residential customers who participated in Vintage 1 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 1 (2009-2010) during the annual enrollment period for that vintage, nor (b) opt out of Vintage 2016) is 0.0027 cents per kWh (including regulatory fee).

27. The reasonable and prudent Rider 7 Vintage 1 DSM EMF billing factor associated with the true-up adjustment for non-residential customers who participated in Vintage 1 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 1 (2009-2010) during the annual enrollment period for that vintage, nor (b) opt out of Vintage 2016) is 0.0017 cents per kWh (including regulatory fee).

28. DEC should continue to use its Collaborative to work with stakeholders to find ways of increasing DSM and EE program impacts and participation, including programs designed to decrease opt-outs and changes to existing or development of new programs as discussed in the testimony of SACE witness Allred.

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

The evidence in support of these findings and conclusions can be found in the Application, the pleadings, the testimony and exhibits in this docket, as well as in the statutes, case law, and rules governing the authority and jurisdiction of this Commission. These findings are informational, procedural, and jurisdictional in nature.

G.S. 62-133.9 grants the Commission the authority to approve an annual rider, outside of a general rate case, for recovery of reasonable and prudent costs incurred in the adoption and implementation of new DSM and EE measures, as well as appropriate rewards for adopting and implementing those measures. Similarly, Commission Rule R8-68 provides, among other things, that reasonable and prudent costs of new DSM or EE programs approved by the Commission shall be recovered through the annual rider described in G.S. 62-133.9 and Commission Rule R8-69. The Commission may also consider in the annual rider proceeding whether to approve any utility incentive (reward) pursuant to G.S. 62-133.9(d)(2)a-c.

Commission Rule R8-69 outlines the procedure whereby a utility applies for and the Commission establishes an annual DSM/EE rider. Commission Rule R8-69(a)(2) defines DSM/EE rider as "a charge or rate established by the Commission annually pursuant to G.S. 62-133.9(d) to allow the electric public utility to recover all reasonable and prudent costs incurred in adopting and implementing new demand-side management and energy efficiency measures after August 20, 2007, as well as, if appropriate, utility incentives, including net lost revenues." Commission Rule R8-69(a)(2). Commission Rule R8-69(c) allows a utility to apply for recovery of incentives for which the Commission will determine the appropriate ratemaking treatment.

G.S. 62-133.9, Commission Rules R8-68 and R8-69 establish a procedure whereby an electric public utility files an application in a unique docket for the Commission's approval of an annual rider for recovery of reasonable and prudent costs of approved EE and DSM programs as well as appropriate utility incentives, potentially including specifically "[a]ppropriate rewards based on capitalization of a percentage of avoided costs achieved by demand-side management and energy efficiency measures." Consistent with this provision, as well as the Commission-approved Sub 831 Mechanism, a portion of the cost recovery and utility incentives the Company seeks through Rider 7 is based on the Company recovering a percentage of the avoided capacity costs achieved by DSM measures, and a separate percentage of the net present value (NPV) of avoided capacity costs and avoided energy costs achieved by EE measures. In addition, the Sub 831 Mechanism provides for a limited period of recovery of the Company's NLR resulting from implementation of its EE measures approved as part of the Sub 831 pilot, net of found revenues. The remaining portion of proposed Rider 7 provides for the recovery, pursuant to the Sub 1032 Mechanism, of DSM/EE program costs, NLR (net of found revenues), and a PPI incentive related to DSM/EE programs approved in the Sub 1032 Order, after the end of the Sub 831 pilot, as well as the Small Business Energy Saver program, which was approved in Docket No. E-7, Sub 1055. Recovery of these costs and utility incentives is also consistent with G.S. 62-133.9, Commission Rules R8-68 and R8-69. Therefore, the Commission concludes that it has the authority to consider and approve the relief the Company is seeking in this docket.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 3

The evidence for this finding and conclusion can be found in DEC's Application, the testimony and exhibits of Company witnesses Barnes and Miller, the affidavit of Public Staff witness Floyd, and the various Commission orders referenced herein.

DEC witness Miller's testimony and exhibits show that the Company's request for approval of Rider 7 is associated with the Sub 831 pilot, as well as the Sub 1032 portfolio of programs and the Small Business Energy Saver program, which was approved in Docket No. E-7, Sub 1055. The direct testimony and exhibits of DEC witness Barnes listed the applicable DSM/EE programs as follows: Appliance Recycling Program; Energy Assessments Program; Energy Efficiency Education Program; Energy Efficient Appliances and Devices; HVAC Energy Efficiency Program; Multi-Family Energy Efficiency Program; My Home Energy Report; Income-Qualified Energy Efficiency and Weatherization Program; Power Manager; Nonresidential Smart $aver® Energy Efficient Food Service Products Program; Nonresidential Smart $aver® Energy Efficient HVAC Products Program; Nonresidential Smart $aver® Energy Efficient IT Products Program; Nonresidential Smart $aver® Energy Efficient Lighting Products Program; Nonresidential Smart $aver® Energy Efficient Process Equipment Products Program; Nonresidential Smart $aver® Energy Efficient Pumps and Drives Products Program; Nonresidential Smart $aver® Custom Program; Nonresidential Smart $aver® Custom Energy Assessments Program; PowerShare®; PowerShare® Call Option; Energy Management and Information Services Pilot Program;[1] Small Business Energy Saver; and Smart Energy in Offices.

In his affidavit, Public Staff witness Floyd also listed the DSM/EE programs and pilots for which the Company seeks cost recovery and noted that each of these programs and pilots has received approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under G.S. 62-133.9.

[1] The Commission issued an Order on November 26, 2014, in Docket No. E-7, Sub 1032 approving DEC's request to discontinue the Energy Management and Information Services Pilot Program.

Thus, the Commission concludes that each of the programs and pilots listed by witnesses Barnes and Floyd has received Commission approval as a new DSM or EE program or pilot and is, therefore, eligible for cost recovery in this proceeding under G.S. 62-133.9.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 4

The evidence for this finding and conclusion can be found in the testimony and exhibits of Company witness Barnes and the affidavit of Public Staff witness Floyd.

DEC witness Barnes testified that the Company reviewed the portfolio of DSM/EE programs and performed prospective analyses of each of its programs and the aggregate portfolio for the Vintage 2016 period, the results of which are incorporated in Barnes Exhibit No. 7. DEC's calculations indicate that with the exception of the Income-Qualified Energy Efficiency and Weatherization Program (which was not cost-effective at the time it was approved by the Commission, but was approved based on its societal benefit) and the HVAC Energy Efficiency Program, all of the programs in the portfolio, individually and in the aggregate, continue to be cost-effective. Witness Barnes explained that since the HVAC Energy Efficiency Program provides efficiency opportunities for such a large component of overall residential usage, and because the program is on the border of being cost-effective, DEC does not plan to discontinue the program. Instead, DEC is currently evaluating opportunities to modify the HVAC Energy Efficiency Program in order to enhance the program and return it to being cost-effective. DEC Witness Barnes indicated that, based on the Company's cost-effectiveness analysis, aside from the HVAC Energy Efficiency Program, none of the programs had been modified or needed to be discontinued.

Public Staff witness Floyd stated in his affidavit that he reviewed DEC's calculations of cost-effectiveness under each of the four standard cost-effectiveness tests - the Utility Cost (UC), Total Resource Cost (TRC), Participant, and Ratepayer Impact Measure tests. He indicated that each program was cost-effective under all four tests, with the exception of the Income-Qualified Energy Efficiency and Weatherization Program and the HVAC Energy Efficiency Program, which are not cost-effective under the UC or TRC tests. Witness Floyd noted that the cost-effectiveness of the HVAC Energy Efficiency Program was impacted by new federal standards that became effective in January 2015, and that DEC intends to discuss continuation of the program with its Collaborative to see if there are program design changes that can be made to improve the cost-effectiveness of this program. Finally, witness Floyd stated that his review indicated that the Sub 1032 portfolio as a whole remains cost-effective.

Based on the foregoing, the Commission concludes that DEC's portfolio of DSM and EE programs is cost-effective and eligible for inclusion in Rider 7. The Commission acknowledges the significant portion of residential customer usage associated with HVAC and that recent changes in the federal efficiency standards applicable to HVAC systems are likely to impact the HVAC EE Program's ability to remain cost-effective. The Commission therefore concludes that prior to DEC filing its next DSM/EE rider case in 2016, DEC and its Collaborative should work to evaluate how the HVAC EE Program can be modified, if at all, such that the Program's cost-effectiveness can be enhanced in the future in order to maintain a viable program. A summary of the Collaborative's findings should be included in the 2016 DSM/EE Rider application. If no solutions or modifications are found which can be implemented to make the HVAC EE program viable in the future, DEC should be prepared to fully justify, in its next DSM/EE rider case, why the HVAC EE Program should not be terminated.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence in support of these findings and conclusions can be found in the testimony and exhibits of DEC witness Ham and the affidavit of Public Staff witness Floyd.

DEC witness Ham testified regarding the EM&V process, activities, and results presented in this proceeding. In her testimony, witness Ham explained that the EMF component of Rider 7 incorporates actual customer participation and evaluated load impacts determined through EM&V and applied pursuant to the EM&V Agreement. In addition, actual participation and evaluated load impacts are used prospectively to update NLR estimated for 2016. In this proceeding, the Company submitted, as exhibits to witness Ham's testimony, process evaluation and impact evaluation studies for My Home Energy Report, Smart Energy Now Pilot, Appliance Recycling Program, Income-Qualified Energy Efficiency (Neighborhoods), Energy Efficient Appliances and Devices (Specialty Bulb measures), and Power Manager. The Company also completed impact evaluation studies for HVAC Energy Efficiency (Tune & Seal) and PowerShare®.

In his affidavit, Public Staff witness Floyd stated that DEC had appropriately addressed EM&V-related recommendations made in previous DSM/EE rider proceedings. Witness Floyd also provided recommendations concerning the content of future EM&V studies for particular EE programs, noting that DEC's implementation of these recommendations would be subject to the consideration of whether the cost would outweigh the benefit. He recommended that:

1. The Public Staff and DEC should further discuss the EM&V information presented in Ham Exhibit B (Smart Energy Now Pilot) and Ham Exhibit E (Energy Efficient Appliances and Devices Program [Specialty Bulb measures]).
2. The Public Staff and DEC should work to coordinate an expeditious review of future planned program evaluations of existing programs and methodologies proposed for future EM&V;
3. Future planned program evaluation plans of existing programs, should include, as applicable, the survey instrument and scoring methodology used to account for net-to-gross (NTG) adjustments;
4. Future light logging studies should consider using stratification criteria to account for variables such as the percentage of people at home during the weekday (in the sample vs. the population) when appropriate;
5. Future evaluations which use an S-curve to estimate free-ridership (or spillover) in any NTG analysis, should provide an explanation of changes made to current S-curves relative to S-curves used in past evaluations of DEC programs;
6. Future evaluations which use technical reference manuals (TRMs) from other states to estimate program savings, should use available data (to the extent that is reasonable and cost-effective do to so) from DEC's Carolinas' service territory when calculating savings using algorithms in these TRMs; and

7. Future evaluation plans (for any program which addresses residential lighting measures) should consider the feasibility of collecting specific data from DEC's Carolinas' service territory to revise the final adjusted in-service rates for program bulbs.

Witness Floyd testified that with respect to program vintages for which EM&V reports were filed in this proceeding, he does not recommend any adjustment to the impacts at this time. Aside from EM&V for the Specialty Bulb measures in the Energy Efficient Appliances and Devices program and the Smart Energy Now Pilot, which DEC and the Public Staff have agreed to further discuss, witness Floyd agreed with DEC witness Barnes' testimony that all program vintages for the original save-a-watt portfolio have been evaluated, that this rider represented a "final" true-up of the program impacts for these vintages and programs, and that except for the two programs mentioned above, he considered these programs and vintages to be complete.

With respect to the Specialty Bulb measures and Smart Energy Now Pilot, witness Floyd concluded that the impacts derived through the EM&V analyses should be accepted for purposes of this proceeding, but may be subject to true-up in next year's proceeding depending upon the result of the discussions between DEC and the Public Staff.

With the exception of those EM&V-related recommendations made by witness Floyd (which were not disputed by the Company), no party contested the EM&V information submitted by the Company. The Commission therefore finds that: (1) the EM&V analyses and reports submitted by DEC are acceptable for purposes of this proceeding; (2) the EM&V recommendations concerning future EM&V reports contained in the affidavit of Public Staff witness Floyd should be approved; and (3) subject to the caveat below, the EM&V reports and applicable effective dates as identified by witness Floyd should be considered complete for purposes of calculating program impacts. The Commission further concludes that the vintages related to the Specialty Bulb measures in the Energy Efficient Appliances and Devices program and the Smart Energy Now Pilot impacted by the EM&V reports still being discussed by DEC and the Public Staff cannot be considered complete. As there are ongoing discussions related to the EM&V for these programs, the affected vintages for these programs may be subject to true-up in future DSM/EE rider proceedings. Therefore, in the next proceeding, the Company should address in its testimony and exhibits any adjustments to the EM&V for these programs, as well as how these adjustments, if any, affect the EMF and program impacts.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 8

The evidence supporting this finding and conclusion is found in the testimony of Public Staff witness Maness.

Witness Maness testified that in accordance with the Sub 831 Settlement, the Commission's Found Revenues Order, Sub 831 Order, and the Sub 1032 Settlement, DEC has continued to reduce NLR by net found revenues in accordance with the Found Revenues Order. Additionally, witness Maness stated that as discussed in the Sub 1050 Proceeding and explained by Company witness Barnes, the Company has begun reducing net found revenues by the monetary impact (negative found revenues) caused by reductions in consumption resulting from the current initiative to replace MV lights with LED fixtures. In his affidavit in Docket No. E-7, Sub 1050, witness Maness stated that the Commission possesses significant discretion as to what items may be included in the calculation of the DSM/EE rider as either NLR or found revenues, but that negative found revenues should be approved only to the extent to which the underlying activity actually reduces the Company's profitability, much like positive found revenues increase profitability. Public Staff witness Maness additionally stated that he also testified in the Sub 1050 Proceeding that the underlying circumstances and impacts on the utility of any proposal to offset positive found revenues with negative ones should be evaluated very carefully, on a case-by-case basis. As the Company had not proposed to include any negative found revenues in Rider 6 in the Sub 1050 Proceeding, DEC and the Public Staff agreed, and the Commission found, that the issue was not ripe for adjudication.

Witness Maness explained that after review, the Public Staff has concluded that DEC's currently ongoing initiative to replace MV lighting with LED fixtures is an activity that can reasonably be considered to produce negative found revenues for inclusion in the Company's calculations. He stated that the Public Staff has reviewed DEC's calculations of negative found revenues and accepts them for purposes of this proceeding.

Based on the evidence presented in this proceeding, the Commission finds and concludes that for purposes of this proceeding, it is reasonable for DEC to include negative found revenues associated with its current initiative to replace MV lighting with LED fixtures as an offset to net found revenues in the Company's calculation of NLR.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 9

The evidence supporting this finding and conclusion is found in the testimony of Company witnesses Miller and Barnes, and in the testimony of Public Staff witness Maness.

Company witness Miller explained that the final true-up of revenue requirements related to the Sub 831 pilot includes calculations that determine the earnings for the entire program and ensure that DEC's compensation is capped so that the actual after-tax return on program costs applicable to EE and DSM program costs does not exceed the predetermined earnings cap levels set out in the Sub 831 Settlement. DEC witness Barnes testified that during the four-year term of the Sub 831 pilot, the actual nominal avoided cost benefits generated by the Sub 831 portfolio of programs are nearly 123% of the target set in the Sub 831 Settlement. Company witness Barnes stated that this achievement entitles the Company to the highest earning cap allowed under the Sub 831 Settlement, the lesser of the permitted avoided cost revenues or 15% of the program costs on an after-tax basis. After comparing the allowed avoided cost revenue calculation to the 15% earnings cap on program cost, the Company determined that it is appropriate to apply the 15% after-tax earnings cap, which is reflected in the final Sub 831 true-up component of Rider 7. DEC witness Miller testified that the Company did not collect more than its earnings cap consisting of program costs plus allowed return.

Public Staff witness Maness also provided testimony pertaining to DEC's calculation of its proposed final earnings cap true-up. Witness Maness stated that per the Company and as agreed to by Public Staff witness Floyd, with the exception of the vintages associated with the EM&V for the Smart Energy Now Pilot and the Specialty Bulb measures of the Energy Efficient Appliances and Devices program, EM&V analyses covering all of the Sub 831 vintage years have been completed. (As discussed previously, the Public Staff and DEC have agreed to further discuss the EM&V for the Smart Energy Now pilot program and the specialty bulb measure of the Energy Efficient Appliances and Devices program; thus, the vintages of these programs covered by the EM&V filed in Ham Exhibits B and E in this proceeding are subject to further adjustment in next year's proceeding.) Public Staff witness Maness also stated that as noted in the letter filed by the Public Staff in Sub 1050 on October 1, 2014, the Public Staff has completed its audit of save-a-watt program costs, and the revised level of costs has also been incorporated into the final calculation. Therefore, subject to future adjustment to vintages of the programs covered by the EM&V filed in Ham Exhibits B and E in this proceeding, witness Maness indicated that the Public Staff has no objection to the Company making an earnings cap true-up in this case, subject to possible future adjustment and further true-up.

Witness Maness also testified that in the Sub 1050 Proceeding, he expressed certain concerns regarding the Company's application of the Sub 831 Settlement provisions regarding interest on various true-ups, and specifically the Company's decision not to calculate interest on the earnings cap overcollection. He discussed the appropriateness of calculating interest on the various true-ups separately, versus netting them as DEC has done. Based upon further discussions with the Company and further internal deliberation, witness Maness indicated that the Public Staff concluded that the Company's approach is reasonable, and that no interest (other than the amount that the Company has calculated for Vintage 3 non-residential DSM) is necessary. Essentially, the earnings cap overcollection has been beneficially offset by the avoided cost revenue requirement being set at 85% of the amount that could be justified throughout the Sub 831 pilot, resulting in customers' bills being lower than they otherwise would have been (in fact, lower than the bills justified by the earnings cap). In this particular case, the Public Staff considers it reasonable to allow this benefit to offset the earnings cap for purposes of the calculation of interest.

Based upon all the evidence presented in this proceeding and the record as a whole, the Commission finds and concludes that, subject to future adjustments and true-ups to vintages of the programs covered by the EM&V information filed in Ham Exhibits B and E in this proceeding, it is reasonable for the Company to make a modified save-a-watt earnings cap true-up in this proceeding, and that the benefit to the customers of the avoided cost revenue requirement previously being set at 85% of the amount that could be justified should be allowed to offset the earnings cap for purposes of the calculation of interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-11

The evidence in support of these findings and conclusions can be found in the Sub 938 Second Waiver Order; the Sub 1032 Order; the testimony of Company witnesses Miller and Barnes; and the testimony of Public Staff witness Maness. The rate period and the scope of the EMF components of Rider 7 are consistent with the Commission's ruling in the Sub 938 Second Waiver Order and the Sub 1032 Order, and are uncontroverted by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-27

The evidence in support of these findings and conclusions can be found in the Sub 831 Found Revenues Order, Sub 938 Waiver, Sub 938 Second Waiver, Sub 979, and Sub 1032 Orders; in the Company's Application, as set forth in the testimony and exhibits of Company witnesses Miller, Ham, and Barnes; and in the testimony of Public Staff witnesses Maness and Floyd.

On March 4, 2015, DEC filed its Application seeking approval of Rider 7, which includes the formula for calculation of Rider EE, as well as the proposed billing factors to be effective for the 2016 rate period. Company witness Miller and Public Staff witness Maness testified that the methods by which DEC has calculated its proposed Rider EE are the Sub 831 Mechanism as described in the Sub 831 Settlement and approved, with certain modifications, in the Sub 831 Order and other relevant Orders of the Commission, and the Sub 1032 Settlement and Sub 1032 Mechanism approved in the Sub 1032 Order.

The Sub 831 Mechanism

DEC witness Miller described the Sub 831 Mechanism as set out in the Sub 831 Settlement and approved in the Sub 831 Order. It was designed to allow the Company to collect revenue equal to 75% of its estimated avoided capacity costs applicable to DSM programs approved as part of the Sub 831 pilot and 50% of the NPV of estimated avoided capacity and energy costs applicable to the same category of EE programs, and to recover NLR for EE programs only. Revenues were to be based on the expected avoided costs and the associated NLR to be realized at an 85% level of achievement of the Company's avoided cost savings target for the applicable vintage. The 85% billing factor was to be used until the true-up to be performed at the end of the four-year pilot (which was Rider 6). Billing factors related to the Sub 831 pilot are calculated separately for residential and non-residential customers, with the charges calculated based on the avoided costs of the programs targeted to each class of customers.

Witness Miller explained that the Sub 831 Mechanism uses vintage years for each of the four calendar year vintages[1] during the Sub 831 pilot. Annual NLR associated with each vintage of EE programs are recovered for a 36-month period, so the recovery of NLR for EE programs for certain vintage years extends several years beyond the initial four-year cost recovery period.

Witness Miller testified that the Sub 831 Settlement provides for a series of vintage true-ups conducted to update revenue requirements, including NLR, based on actual customer participation results for each vintage. EM&V results are applied during vintage true-ups in accordance with the EM&V Agreement. The true-ups for each vintage also incorporate the difference between (1) the revenues collected based on billings at 85% of targeted savings, based on estimated participation levels and initial assumptions of load impacts; and (2) the allowable

[1] Vintage 1 is an exception in terms of length. Vintage 1 is the 19-month period beginning June 1, 2009 and ending December 31, 2010, as a result of the approval of the Sub 831 programs prior to the approval of the Sub 831 Mechanism. The remaining Sub 831 vintages are 12-month periods aligning with calendar years as follows: Vintage 2 (January 1, 2011 through December 31, 2011); Vintage 3 (January 1, 2012 through December 31, 2012); and Vintage 4 (January 1, 2013 through December 31, 2013).

revenues based on actual participation levels and load impacts. The cost of pilot programs or new programs introduced during a vintage year may be recovered during these vintage true-ups.

Witness Miller noted that after the end of the Sub 831 pilot, there is to be a final true-up, including a final comparison of the revenues collected from customers through Rider EE during the Sub 831 pilot to 100% of the amount of revenue the Company is authorized to collect from customers based on the independently measured and verified results. She further testified that any difference will be flowed through to or collected from customers and that any amounts owed to customers will be refunded with interest at a rate to be determined by the Commission in the first true-up proceeding in which an overcollection occurs.

Witness Miller testified that the final true-up is also utilized to include a determination of the earnings for the entire program to ensure that the after-tax rate of return on actual program costs applicable to EE and DSM programs does not exceed the predetermined earnings cap levels set out in the Sub 831 Settlement. Any excess earnings collected from customers will be refunded to customers with interest.

Witness Miller further testified that under the Sub 831 Mechanism, pursuant to the Sub 938 First Waiver Order, qualifying non-residential customers[1] may opt out of the DSM and/or EE portion of Rider EE during annual election periods. If a customer opts into a DSM program (or never opted out), it is required to participate for three years in the programs and rider. If a customer chooses to participate in an EE program (or never opted out), that customer is required to pay the EE-related avoided cost revenue requirements and the NLR for the corresponding vintages of the programs in which it participated. Customers that opt out of the Company's DSM or EE programs remain opted-out for the term of the Sub 831 pilot, unless they choose to opt back in during any of the succeeding annual election periods, which occur from November 1 to December 31 each year. If a customer participates in any vintage of programs, the customer is subject to all true-up provisions of the approved Rider EE for any vintages in which the customer participates.

Witness Miller explained that proposed Rider 7 consists, in part, of five components related to the Sub 831 pilot, which are all calculated pursuant to the Sub 831 Mechanism: (1) an EMF component designed to collect the final half-year of NLR for Vintage 4 EE programs; (2) an EMF component that consists of the true-up of the third year of NLR for Vintage 4 EE programs; (3) an EMF component which consists of the true-up of the final year of NLR for participants in Vintage 3 EE programs; (4) an EMF component for Vintages 1-4 resulting from the final EM&V; and (5) an EMF component for Vintages 1-4 resulting from the final true-up process.

<u>The Sub 1032 Mechanism</u>

Company witness Miller testified that the Sub 1032 Mechanism, which replaces the Sub 831 Mechanism, is set out in the Sub 1032 Settlement, which was approved in the Sub 1032

[1] Individual commercial customer accounts with annual energy usage of not less than 1,000,000 kWh and any industrial customer account.

Order. The Sub 1032 Mechanism is designed to allow the Company to collect revenue equal to its incurred program costs[1] for a rate period plus a PPI based on shared savings achieved by the Company's DSM and EE programs, and to recover NLR for EE programs only. The Company will continue to recover NLR associated with a particular vintage for a maximum of 36 months or the life of the measure, or until the implementation of new rates in a general rate case to the extent that the new rates are set to recover NLR.

Witness Miller noted that the Sub 1032 Mechanism also employs a vintage year concept based on the calendar year.[2] In each annual rider filing, prior calendar year vintages will be trued up to the extent possible, reflecting actual participation and verified EM&V results, applied pursuant to the EM&V Agreement.

Under the Sub 1032 Settlement, as witness Miller explained, deferral accounting may be used for over- and under-recoveries of costs eligible for recovery through the annual DSM/EE rider. The balance in the deferral accounts, net of deferred income taxes, may accrue a return at the net-of-tax rate of return approved in the Company's then most recent general rate case. The methodology used for the calculation of interest shall be the same as that typically utilized for the Company's Existing DSM Program Rider proceedings. Pursuant to Commission Rule R8-69(c)(3), the Company will not accrue a return on NLR or the PPI.

Witness Miller testified that pursuant to the Sub 1032 Settlement, the PPI is calculated by multiplying the net dollar savings achieved by the system portfolio of DSM and EE programs by a factor of 11.5%. The system amount of PPI is then allocated to North Carolina retail customer classes in order to derive customer rates. DEC witness Barnes testified that the calculation of the PPI is based on avoided cost savings achieved through the implementation of the Company's DSM and EE programs, net of program costs.

Witness Barnes testified that consistent with the notice that the Company filed with the Commission on December 18, 2013 in Docket No. E-7, Sub 1032, the Company updated the avoided capacity rates used to estimate Vintage 2016 to reflect the rates contained in the Stipulation of Settlement among DEC, Duke Energy Progress, LLC,[3] and the Public Staff, filed October 29, 2013 in Docket No. E-100, Sub 136. Public Staff witness Floyd explained that DEC also updated the avoided transmission and distribution (T&D) rates to those determined by the avoided cost study conducted pursuant to the Sub 1032 Order. Witness Floyd stated that while the updated avoided cost rate was higher than originally filed in the Sub 136 case, the updated T&D rates were substantially lower, which netted to fewer avoided cost benefits from all programs.

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[1] Commission Rule R8-68(b)(1) defines "program costs" as all reasonable and prudent expenses expected to be incurred by the electric public utility, during a rate period, for the purpose of adopting and implementing new DSM and EE measures previously approved pursuant to Commission Rule R8-68.

[2] To distinguish from Sub 831 vintages, each vintage under the Sub 1032 Mechanism is referred to by the calendar year of its respective rate period (*e.g.*, Vintage 2015).

[3] Effective August 1, 2015, Duke Energy Progress, Inc., converted to a limited liability corporation.

Under the Sub 1032 Settlement, as with the Sub 938 First Waiver Order and the Sub 831 pilot, qualifying non-residential customers may opt out of the DSM and/or EE portion of Rider EE during annual election periods. Rider EE will be charged to all customers who have not elected to opt out during an enrollment period and who participate in any vintage year of programs, and these customers will be subject to all true-up provisions of the approved Rider EE for any vintage in which the customers participate. Witness Miller explained that the Sub 1032 Mechanism affords an additional opportunity for participation, whereby qualifying customers may opt in to the Company's EE and/or DSM programs during the first five business days of March. Customers who elect to begin participating in the Company's EE and DSM programs during the special "opt-in period" during March of each year will be retroactively billed the applicable Rider EE amounts back to January 1 of the vintage year, such that they will pay the appropriate Rider EE amounts for the full rate period.

Witness Miller testified that proposed Rider 7 consists of five components related to the Sub 1032 Mechanism: (1) a prospective Vintage 2014 component designed to collect the third year of estimated NLR for the Company's 2014 vintage of EE programs; (2) a prospective Vintage 2015 component designed to collect the second year of estimated NLR for the Company's 2015 vintage of EE programs; (3) a prospective Vintage 2016 component designed to collect program costs, the PPI, and the first year of NLR for the Company's 2016 vintage of EE programs; (4) a prospective Vintage 2016 component designed to collect program costs and the PPI for the Company's 2016 vintage of DSM programs; and (5) an EMF component which consists of the true-up of Vintage 2014 program costs, shared savings and participation for the Company's 2014 vintage of EE and DSM programs.

<u>Allocation of Costs and Incentives</u>

Company witness Miller testified that under both mechanisms, program costs and incentives for EE programs targeted at retail residential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the ratio of North Carolina retail kWh sales (grossed up for line losses) to total retail kWh sales (grossed up for line losses), and then recovered only from North Carolina retail residential customers. Revenue requirements related to EE programs targeted at retail non-residential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the ratio of North Carolina retail kWh sales (grossed up for line losses) to total retail kWh sales (grossed up for line losses), and then recovered from only North Carolina retail non-residential customers. The portion of revenue requirements related to NLR is computed based on the kilowatt (kW) and kWh savings of North Carolina retail customers.

For DSM programs, witness Miller noted, the aggregated revenue requirement for all retail DSM programs targeted at both residential and non-residential customers across North Carolina and South Carolina is allocated to the North Carolina retail jurisdiction based on the North Carolina retail contribution to total retail peak demand. Both residential and non-residential customer classes are allocated a share of total system DSM revenue requirements based on each group's contribution to total retail peak demand.

The allocation factors used in DSM/EE EMF true-up calculations for each vintage are based on the Company's most recently filed Cost of Service studies at the time that the Rider EE filing incorporating the true-up is made. If there are subsequent true-ups for a vintage, the allocation factors used will be the same as those used in the original DSM/EE EMF true-up calculations.

Prospective Components of Proposed Rider 7

Company witness Miller testified that for the prospective components of Rider EE, NLR are estimated by multiplying the portion of the Company's tariff rates that represent the recovery of fixed costs by the estimated North Carolina retail kW and kWh reductions applicable to EE programs by rate schedule, and reducing this amount by estimated found revenues. The fixed cost portion of the tariff rates is calculated by deducting the recovery of fuel and variable operation and maintenance costs from the tariff rates. The NLR totals for residential and non-residential customers are then reduced by North Carolina retail found revenues computed using the weighted average lost revenue rates for each customer class. For the EMF components of Rider EE, NLR are calculated by multiplying the fixed cost portion of the tariff rates by the actual and verified North Carolina retail kW and kWh reductions applicable to EE programs by rate schedule, and reducing this amount by actual found revenues.

Witness Miller explained that the billing factors are computed separately for EE and DSM measures by dividing the revenue requirements for each customer class, residential and non-residential, by the forecasted sales for the rate period for the customer class. For non-residential rates, the forecasted sales exclude the estimated sales to customers who have elected to opt out of paying Rider EE. The non-residential billing factors are separately computed for each vintage. Pursuant to the Sub 938 Second Waiver Order and the Sub 1032 Order, the rate period for the prospective components of Rider 7 is January 1, 2016 through December 31, 2016.

Witness Miller further testified that the prospective revenue requirements for Vintage 2014 are determined separately for residential and non-residential customer classes and are based on the third year of estimated NLR for the Company's Vintage 2014 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and the Company's rates approved in DEC's most recent general rate case, Docket No. E-7, Sub 1026, which became effective September 25, 2013 (Sub 1026 Rates).

The prospective revenue requirements for Vintage 2015 are determined separately for residential and non-residential customer classes and are based on the second year of estimated NLR for the Company's Vintage 2015 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and the Sub 1026 Rates.

The prospective revenue requirements for Vintage 2016 EE programs include estimates of program costs, a PPI, and the first year of NLR determined separately for residential and non-residential customer classes. The program costs and shared savings incentive are computed at the system level and allocated to North Carolina retail operations. The NLR for EE programs are based on estimated North Carolina retail kW and kWh reductions and the Sub 1026 Rates.

On May 15, 2015, witness Miller filed supplemental testimony and exhibits reflecting prospective billing factors for Rider 7 of 0.3361 cents per kWh for all North Carolina retail residential customers, 0.2164 cents per kWh for non-residential Vintage 2016 EE participants, 0.0709 cents per kWh for non-residential Vintage 2016 DSM participants, 0.0345 cents per kWh for non-residential Vintage 2015 EE participants, and 0.0256 cents per kWh for non-residential Vintage 2014 EE participants.

EMF Component of Rider 7

Company witness Miller testified that pursuant to the Sub 938 Second Waiver Order and the Sub 1032 Order, the "test period" for the Vintage 2014 EMF component is January 1, 2014 through December 31, 2014. As the Sub 938 Second Waiver Order allows the EMF to cover multiple test periods, the test period for the EMF related to the final true-up includes the four prior Sub 831 vintages: Vintage 1 (June 1, 2009 through December 31, 2010); Vintage 2 (January 1, 2011 through December 31, 2011); Vintage 3 (January 1, 2012 through December 31, 2012); and Vintage 4 (January 1, 2013 through December 31, 2013).

Company witness Miller explained the updates in this proceeding to the Vintage 2014 estimate filed in 2013 that comprise the Vintage 2014 EMF component of Rider 7. Estimated participation for Vintage 2014 was updated for actual participation for the period January through December 2014. With regard to NLR, estimated participation for the Year 1 Vintage 2014 estimate assumed a January 1, 2014 sign-up date and used a half-year convention, while the NLR Year 1 Vintage 2014 true-up was updated for actual participation for the period January through December 2014 and actual 2014 lost revenue rates. Found revenues for Year 1 of Vintage 2014 were trued up according to Commission-approved guidelines. To reflect the results of EM&V, Vintage 2014 estimated avoided cost savings were updated pursuant to the EM&V Agreement. Finally, while the Vintage 2014 estimate included only the programs approved prior to the filing of the estimated Vintage 2014 revenue requirement, the Vintage 2014 true-up was updated for new programs and pilots approved and implemented during Vintage 2014. For DSM programs, the Vintage 2014 true-up reflects the actual quantity of demand reduction capability for the Vintage 2014 period.

Actual year one (2014) NLR for Vintage 2014 were calculated using actual kW and kWh savings by North Carolina retail participants by customer class in 2014, based on actual participation and load impacts applied according to the EM&V Agreement. The rates applied to the kW and kWh savings are those in effect for 2014, reduced by fuel and variable operation and maintenance costs. NLR were then offset by actual found revenues for Year 1 NLR of Vintage 2014. NLR were calculated by rate schedule within the residential and non-residential customer classes.

Witness Miller explained that for the Vintage 4 EMF component, avoided costs for Vintage 4 EE programs are being trued up based on updated EM&V participation results and program costs. Avoided costs for Vintage 4 DSM programs are being trued up to correct participation results and program costs. NLR for all years were trued up for updated EM&V participation results. The actual kW and kWh savings were as experienced during the period

January 1, 2013 through December 31, 2013. The rates applied to the kW and kWh savings are the rates that were in effect during each period the lost revenues were earned.

Witness Miller testified that avoided costs for Vintage 3 EE programs are being trued up based on updated EM&V results and program costs. Avoided costs for Vintage 3 DSM programs are being trued up to reflect participation results and program costs. NLR for all years of Vintage 3 EE programs were trued up for updated EM&V participation results. The actual kW and kWh savings were as experienced during the period July 1, 2012 through December 31, 2012. NLR associated with January through June 2012 participation in Vintage 3 have been incorporated into the Sub 1026 Rates, which went into effect on September 25, 2013. As a result, DEC has discontinued collection of NLR associated with January through June 2012 participation in Vintage 3 through Rider EE effective September 25, 2013. The rates applied to the kW and kWh savings are the rates that were in effect during each period lost revenues were earned.

According to witness Miller, avoided costs for Vintage 2 EE programs are being trued up based on updated EM&V participation results and program costs. Avoided costs for Vintage 2 DSM programs are being also being trued up to reflect updated EM&V participation results and program costs. The actual kW and kWh savings were as experienced during the period January 1, 2011 through December 31, 2011. DEC has incorporated lost revenues associated with participation in Vintage 2 into the Sub 1026 Rates. As a result, Rider 7 includes collection of NLR for the third year of Vintage 2 only for the period January 1, 2013 through September 25, 2013. The rates applied to the kW and kWh savings are the rates that were in effect during each period lost revenues were earned. In addition, witness Miller noted that Vintage 1 is being trued up to reflect updated DSM program costs.

Witness Miller explained that the final true-up of revenue requirements related to the Sub 831 pilot includes a final comparison of the revenues collected from customers through Rider EE during the Sub 831 pilot to 100% of the amount of revenue DEC is authorized to collect from customers based on the independently measured and verified results as described in the Sub 831 Settlement. The final true-up process also includes calculations that determine the earnings for the entire program and ensure that DEC's compensation is capped so that the actual after-tax return on program costs applicable to EE and DSM program costs does not exceed the predetermined earnings cap levels set out in the Sub 831 Settlement (as further discussed in the Evidence for Finding and Conclusion No. 9). The Company has updated Vintages 1-4 for the final participation and EM&V results. Therefore, although Rider 7 includes estimates for Vintage 3 Year 4 of NLR, and Vintage 4 Year 3 and 4 NLR, no further true-ups will be made to adjust these components of Rider 7, and all adjustments relating to the Sub 831 pilot are included in the EMF component of the Rider. The Company is also revising the revenue estimated to be collected in 2015 by utilizing the fall 2014 forecast and the most recent opt-out information. Finally, the final true-up of Sub 831 clarifies the amount of gross receipts tax due and paid during the life of each vintage year.

Witness Miller testified that, as a result of the final true-up, DEC owes interest relating to one component. The Company over-collected for the Vintage 3 Non-Residential DSM program. Witness Miller explained that the Company has calculated interest using the same methodology utilized in its North Carolina fuel rider proceedings, whereby interest is calculated at 10% from the mid-point of the overcollection period to the mid-point of the give-back period. Witness Miller added that this methodology benefits customers by using a higher interest rate than DEC's weighted average cost of capital approved in its most recent rate case, and provides a simple and consistent approach.

Overall, as set forth on Supplemental Miller Exhibit 1, the Company proposed an EMF of 0.0260 cents per kWh for its North Carolina retail residential customers, 0.0150 cents per kWh for non-residential Vintage 2014 EE participants, (0.0044) cents per kWh for non-residential Vintage 2014 DSM participants, 0.0326 cents per kWh for non-residential Vintage 4 EE participants, 0.0005 cents per kWh for non-residential Vintage 4 DSM participants, 0.0261 cents per kWh for non-residential Vintage 3 EE participants, (0.0017) cents per kWh for non-residential Vintage 3 DSM participants, 0.0148 cents per kWh for non-residential Vintage 2 EE participants, 0.0019 cents per kWh for non-residential Vintage 2 DSM participants, 0.0027 cents per kWh for non-residential Vintage 1 EE participants, and 0.0017 cents per kWh for non-residential Vintage 1 DSM participants.

Public Staff Review of Company Rider 7 Calculations

As discussed above, Public Staff witness Floyd filed an affidavit in this proceeding discussing several topics and issues related to the Company's filing. The Public Staff pointed out that none of these topics and issues necessitate an adjustment in this particular proceeding to the Company's billing factor calculations. However, as witness Floyd notes, the Public Staff and DEC have agreed to further discuss the EM&V for the Smart Energy Now Pilot and the Specialty Bulb measures of the Energy Efficient Appliances and Devices program, and therefore agree that the vintages of these programs covered by the EM&V filed in Ham Exhibits B and E in this proceeding are subject to possible adjustment in next year's proceeding depending upon the outcome of those discussions.

Public Staff witness Maness testified that his investigation of DEC's filing in this proceeding focused on whether the Company's proposed DSM/EE billing factors (a) were calculated in accordance with the Sub 831 Settlement (as modified by the Commission) and the Sub 1032 Settlement, as applicable, as well as other relevant Commission orders, and (b) otherwise adhered to sound ratemaking concepts and principles. With the possible exception of the EM&V items identified by witness Floyd, which may require adjustment in next year's proceeding, witness Maness testified that he believes that the Company has calculated the Rider 7 billing factors in a manner consistent with G.S. 62-133.9, Commission Rule R8-69, the Sub 831 Settlement as modified by the Commission, the EM&V Agreement, the Sub 1032 Settlement, and other relevant Commission Orders. He noted that the while the Public Staff and DEC became aware of certain relatively minor input and calculation errors in the determination of the billing factors, corrections of these minor errors were appropriately addressed by DEC in its supplemental filing made on May 15, 2015 and are reflected in the revised billing factors included in Miller Supplemental Exhibit 1 and Maness Exhibit I.

Witness Maness also provided testimony relating to DEC's calculation of its proposed final earnings cap true-up, as discussed in the Evidence and Conclusion for Finding of Fact No. 9, and negative found revenues, as discussed in the Evidence and Conclusion for Finding of Fact No. 8.

Witness Maness also testified that as part of its investigation in this proceeding, the Public Staff performed a review of the DSM/EE program costs incurred by DEC during the 12-month period ended December 31, 2014. To accomplish this, the Public Staff selected and reviewed a sample of source documentation for test year costs included by the Company for recovery through the DSM/EE riders. Review of this sample was intended to test whether the costs included by the Company in the DSM/EE riders are valid costs of approved DSM and EE programs. The Public Staff's review resulted in only one error being found in the costs included in the sample; however, this error had already been corrected by DEC in its books and records. Therefore, no adjustments to program costs were found necessary as a result of this review.

Based on the results of the Public Staff's investigation, witness Maness recommended approval of Rider 7 proposed by DEC in its supplemental filing in this proceeding. He concluded that all the recommended billing factors in Miller Supplemental Exhibit 1 and Maness Exhibit I should be approved subject to any appropriate and reasonable true-ups in future cost recovery proceedings consistent with the Sub 831 and Sub 1032 Orders, as well as other relevant orders of the Commission, including the Commission's final Order in this proceeding.

Other Parties Comments and Recommendations Regarding Rider 7

In its Post-Hearing Letter, NCSEA stated that it does not challenge the reasonableness or prudence of any costs for which DEC seeks recovery in its Rider 7 application. However, NCSEA stated that it wanted to provide a temporal context for DEC's proposed DSM and EE recovery rider. As such, NCSEA included several pictorial graphs in its Letter.

In its Post-Hearing Brief, SACE stated that it supports the approval of DEC's Rider 7.

Conclusions on Calculations of Rider EE

Based on all the evidence presented above and on the record, the Commission finds and concludes that the components of Rider 7, as revised in Miller Supplemental Exhibit 1 and Maness Exhibit I, appropriately reflect the Commission's findings and conclusions herein, as well as the Commission's findings and conclusions as set forth in the Sub 831 Order, the Sub 938 First Waiver Order, the Sub 938 Second Waiver Order, the Found Revenues Order, the Sub 979 Order, and the Sub 1032 Order.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 28

The evidence in support of this finding and conclusion can be found in the testimony of DEC witness Barnes and SACE witness Allred.

Company witness Barnes noted that Vintage 2014 of the EE and DSM programs produced over 546 million kWh of energy savings and nearly 880 megawatts (MW) of capacity savings, which produced NPV avoided cost savings of $324 million. Since the beginning of the Sub 831 pilot, the Company has generated over 2,030 gigawatt-hours of energy reductions, over 980 MW of capacity reductions, and nearly $925 million in nominal avoided cost benefits.

In regard to the opting out by qualifying industrial and commercial customers, witness Barnes testified that these opt-outs have had a negative effect on the Company's overall non-residential impacts. For Vintage 2014, 1,782 eligible customer accounts opted out of participating in the non-residential portfolio of EE programs, constituting slightly more than 15% of eligible customer accounts, but nearly 49% of the load for all eligible customers. To reduce opt-outs, the Company has added the March opt-in window (which resulted in 101 customers' accounts accounting for a total annual usage of approximately 147,295 MWh electing to opt in March 2014), restructured some programs (including increasing the incentive for the Non-Residential Smart $aver® Program), and plans to investigate adding additional measures and programs to attract these customers.

SACE witness Allred testified that the Company has achieved significant EE savings and that SACE supports the Company's requested Rider 7. Witness Allred also noted that the Company's energy savings forecasts are declining and the percentage of non-residential customers electing to opt out of the Company's DSM and EE programs is increasing. While acknowledging DEC's efforts to increase non-residential participation in DSM/EE programs, he recommended additional improvements in the Company's DSM/EE efforts, including several recommendations that could encourage commercial and industrial customers to participate in DEC's DSM/EE programs. Witness Allred made specific recommendations regarding ways to expand and improve the Company's non-residential programs, as well as its residential programs, including low-income program opportunities. Witness Allred also made specific recommendations regarding low-income EE programs and the operation of the Collaborative.

In its Post-Hearing Brief, SACE reiterated several statements testified to by its witness Allred. SACE stated that it supports the approval of DEC's Rider 7 and recommends that the Commission direct that the Company take the following steps to ramp up its energy savings: (1) adopt new programs based on best practices from around the country, including a non-residential self-direct program, on-bill financing programs for residential and non-residential customers, and additional low-income residential EE programs; and (2) enhance the reporting of EE program performance metrics in future applications for new DSM/EE riders by including detailed cost category fields for each EE program.

CONCLUSIONS

The Commission continues to encourage DEC and other stakeholders to find ways that would improve residential and non-residential program participation. Due to the ability of certain non-residential customers to opt out of the DSM/EE rider, it may be difficult to attract non-residential participation, either through increased incentives or restructuring of programs.

The Commission finds and concludes that the Collaborative is the appropriate forum for reviewing potential programs and enhancements to existing DSM/EE programs in DEC's service territory. Specifically, the Commission finds that the Collaborative should continue to discuss how to increase program participation and impacts, reduce opt-outs, and the specific recommendations made by witness Allred regarding new programs or enhancements to existing programs.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby approves the calculation of Rider EE as filed by DEC and revised in the supplemental testimony and exhibits of witness Miller and the supplemental exhibits of witness Barnes, and the resulting billing factors as set forth in Miller Supplemental Exhibit 1 and Maness Exhibit I, to go into effect for the rate period January 1, 2016, through December 31, 2016, subject to appropriate true-ups in future cost recovery proceedings consistent with the Sub 831 Order, the Sub 1032 Order, and other relevant orders of the Commission.

2. That DEC shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket and the Company shall file such proposed customer notice for Commission approval as soon as practicable.

3. That the Company shall incorporate the recommendations made by Public Staff witness Floyd into future EM&V reports filed with the Commission in subsequent DSM/EE rider proceedings.

4. That in its next proceeding, the Company shall address in testimony and exhibits any adjustments to the EM&V for the Smart Energy Now Pilot and the Specialty Bulb measures in the Energy Efficient Appliance and Devices program, as well as how these adjustments, if any, affect the EMF and program impacts.

5. That DEC shall continue to use its Collaborative to work with stakeholders and discuss program offerings that could reduce the number of opt-outs.

6. That the specific recommendations made by witness Allred regarding new programs or enhancements to existing programs shall be considered by the Collaborative.

ISSUED BY ORDER OF THE COMMISSION.
This 21st day of August, 2015.

THE NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

Commissioner Susan W. Rabon did not participate in this decision.

DOCKET NO. E-7, SUB 1081

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Duke Energy Carolinas, LLC,	)	ORDER APPROVING
for Approval of Business Energy Report Pilot	)	PILOT PROGRAM
Program	)	

BY THE COMMISSION: On May 7, 2015, Duke Energy Carolinas, LLC (DEC or the Company), filed an application seeking approval of a Business Energy Report Pilot Program (Pilot) as a new energy efficiency (EE) program under G.S. 62-133.9 and Commission Rule R8-68.

DEC stated that the Pilot is designed to achieve energy savings by providing participants with periodic energy usage reports that give them energy consumption data that allow comparison to usage of other similar customers. The reports are also designed to motivate participants to become more energy efficient by including EE tips and suggestions to reduce energy consumption. No monetary incentives will be given to participants. The only incentive each participant will receive is a regular Business Energy Report.

The application includes estimates of the Pilot's impacts, costs, and benefits used to calculate the cost-effectiveness of the Pilot. DEC's calculations indicate that the Pilot will be cost-effective under the Total Resource Cost (TRC) and the Utility Cost (UC) tests, but not under the Ratepayer Impact Measure (RIM) test.

On May 28, 2015, the Southern Alliance for Clean Energy filed a letter in support of DEC's application.

On June 5, 2015, the Commission granted the Public Staff and any other interested parties an extension of time to July 23, 2015, in which to file comments.

The Public Staff filed its comments on the Pilot on July 23, 2015. No other party filed comments.

The Public Staff stated in its comments that the filing contains the information required by Commission Rule R8-68(c) and is consistent with G.S. 62-133.9, R8-68(c), and the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Mechanism), approved by Order dated January 20, 2015, in Docket No. E-2, Sub 931. The Public Staff noted that DEC's estimates of program costs, net lost revenue, and performance incentive, appeared to be consistent with the requirements of the Mechanism.

The Public Staff noted that DEC's application states that the estimates of energy saving impacts for the Pilot were based on Duke Energy Carolinas, LLC's Smart Energy Now (SEN) Pilot Program. However, the Public Staff's investigation determined that DEC relied more on the Pilot vendor's experience with other similar behavioral EE programs for nonresidential customers as the basis for the savings rate. The Public Staff stated that it had some uncertainty over the estimated savings both because of ongoing questions about the evaluation and measurement of SEN savings and because of the difficulty of using impacts from other jurisdictions to project savings in North Carolina. The Public Staff further stated that one purpose of a pilot is to gain more reliable data for savings estimates, and that approval of a pilot is not a commitment to continuation of a program or measure that is later discovered to not be cost-effective. Therefore, the Public Staff concluded that it was reasonable to allow DEC to proceed with the Pilot.

The Public Staff stated in its comments that it had reviewed the avoided costs used to determine cost-effectiveness of the Pilot and noted that DEC had stated it used the avoided capacity cost rates from its filing in Docket No. E-100, Sub 136, and the avoided energy cost rates from DEC's 2012 Integrated Resource Plan. The Public Staff stated that it found these rates to be sufficient for purposes approving the Pilot.

The Public Staff presented this matter at the Commission's Regular Staff Conference on August 17, 2015. The Public Staff stated that the Pilot has the potential to encourage EE, appears to be cost effective, is consistent with DEC's IRP, and is in the public interest. The Public Staff recommended that the Commission approve the Pilot as a new EE program pursuant to Commission Rule R8-68, and determine the appropriate recovery of program costs, net lost revenues, and performance incentives associated with the Pilot in the annual DSM/EE rider proceeding consistent with G.S. 62-133.9, Commission Rule R8-69, and the current DSM/EE cost recovery mechanism.

Based on the foregoing and the entire record in this proceeding, the Commission finds good cause to approve the Pilot as a new EE program for a three-year period effective upon implementation.

Further, the Commission finds and concludes that the appropriate ratemaking treatment for the Pilot, including program costs, net lost revenues, and performance incentives, should be determined in DEC's annual cost recovery rider approved pursuant to Commission Rule R8-69.

IT IS, THEREFORE, ORDERED as follows:

1. That the Pilot is hereby approved as a new energy efficiency program pursuant to Commission Rule R8-68.

2. That the Pilot is approved for a three-year period, beginning on the date of implementation by DEC.

3. That DEC shall file with the Commission, within 10 days of Pilot implementation, a notice that the Pilot has begun.

4. That the Commission shall determine the appropriate ratemaking treatment for the Pilot, including program costs, net lost revenues, and performance incentives, in DEC's annual cost recovery rider, in accordance with G.S. 62-133.9 and Commission Rule R8-69.

5. That DEC shall file with the Commission, within 10 days following the date of this order, a revised tariff showing the effective date of the tariff.

ISSUED BY ORDER OF THE COMMISSION.
This the __19th__ day of August, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-7, SUB 1093

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Duke Energy Carolinas,	)	
LLC, for Approval of EnergyWise for	)	ORDER APPROVING PROGRAM
Business Program	)	

BY THE COMMISSION: On August 20, 2015, Duke Energy Carolinas, LLC (DEC or the Company), filed an application seeking approval of an EnergyWise for Business Program (Program) as a new energy efficiency (EE) program under G.S. 62-133.9 and Commission Rule R8-68.

DEC states that the Program is designed to provide small business customers with the ability to participate in demand response (DR) events. The Program will offer participants a choice from two measures. The first measure is a programmable thermostat measure that DEC can use to remotely control the participant's HVAC system during DR events. It will also allow participants to manage their thermostats and HVAC systems remotely with preselected settings that save energy based on a schedule that works best for the business. The second measure will allow the Company to install a load control device on the customer's HVAC system, which will be used to cycle the customer's HVAC based on a preselected cycling strategy, producing demand savings during DR events. There will be three levels of summer participation, each providing a predetermined incentive based on the level of DR selected by the participant. An additional incentive will be given to customers wishing to participate in the winter season DR. The Program will be limited to 40 hours of DR for each season, and up to 4 hours per day.

DEC's application includes estimates of the Program's impacts, costs, and benefits used to calculate the cost-effectiveness of the Program. DEC's calculations indicate that the Program will be cost-effective under the Total Resource Cost and the Utility Cost tests, and also under the Ratepayer Impact Measure test.

On September 22, 2015, the Commission granted the Public Staff and other interested parties an extension of time to October 5, 2015, in which to file comments.

On September 24, 2015, the Southern Alliance for Clean Energy filed a letter in support of DEC's application.

On October 5, 2015, the Public Staff filed comments on the Program. No other party filed comments.

The Public Staff stated in its comments that the filing contains the information required by Commission Rule R8-68(c) and is consistent with G.S. 62-133.9, R8-68(c), and the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Mechanism), approved by Order dated October 29, 2013, in Docket No. E-7, Sub 1032. The Public Staff stated that DEC's estimates of program costs, net lost revenue, and performance incentive, appeared to be consistent with the requirements of the Mechanism.

The Public Staff also stated in its comments that it had reviewed the avoided costs used to determine cost-effectiveness of the Program and noted that DEC had stated it used the avoided capacity cost rates from its filing in Docket No. E-100, Sub 136, and the avoided energy cost rates from DEC's 2012 Integrated Resource Plan (IRP). The Public Staff stated that it found these rates to be sufficient for purposes of approving the Program.

The Public Staff also stated in its comments that while DEC filed the Program as a new EE program, it is more appropriate to treat it as a new demand-side management (DSM) program. While it has the potential to produce both capacity and energy savings impacts, it is evident that the majority of the impacts reside in avoided capacity and transmission and distribution. This indicates that the Program is more of a DSM program than an EE program.

The Public Staff presented this matter at the Commission's Regular Staff Conference on October 26, 2015. The Public Staff stated that the Program has the potential to encourage DSM and EE, appears to be cost effective, is consistent with DEC's IRP, and is in the public interest. The Public Staff recommended that the Commission approve the Program as a new DSM program pursuant to Commission Rule R8-68, and determine the appropriate recovery of program costs, net lost revenues, and performance incentives associated with the Program in the annual DSM/EE rider proceeding consistent with G.S. 62-133.9, Commission Rule R8-69, and the current DSM/EE cost recovery Mechanism.

Based on the foregoing and the entire record in this proceeding, the Commission finds good cause to approve the Program as a new DSM program. The Commission further finds and concludes that the appropriate ratemaking treatment for the Program, including program costs, net lost revenues, and performance incentives, should be determined in DEC's annual cost recovery rider approved pursuant to Commission Rule R8-69.

IT IS, THEREFORE, ORDERED as follows:

1. That the Program is hereby approved as a new Demand Side Management program pursuant to Commission Rule R8-68.

2. That the Commission shall determine the appropriate ratemaking treatment for the Program, including program costs, net lost revenues, and incentives, in DEC's annual cost recovery rider, in accordance with G.S. 62-133.9 and Commission Rule R8-69.

3. That DEC shall file with the Commission, within 10 days following the date of this Order, a revised tariff showing the effective date of the tariff.

ISSUED BY ORDER OF THE COMMISSION.
This the ___27th__ day of October, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

DOCKET NO. E-2, SUB 1070

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application of Duke Energy Progress, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69	))))	ORDER APPROVING DSM/EE RIDER AND REQUIRING FILING OF PROPOSED CUSTOMER NOTICE

HEARD: Tuesday, September 15, 2015, at 9:50 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Chairman Edward S. Finley, Jr., and Commissioners Bryan E. Beatty, Susan W. Rabon, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Duke Energy Progress, LLC:

Brian L. Franklin, Associate General Counsel, Duke Energy Corporation, DEC 45A / Post Office Box 1321, 550 South Tryon Street, Charlotte, North Carolina 28201-1006

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 East Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolina Industrial Group for Fair Utility Rates II:

Adam Olls, Bailey & Dixon, LLP, Post Office Box 1351, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27602

For the North Carolina Sustainable Energy Association:

Peter H. Ledford, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Southern Alliance for Clean Energy:

Gudrun Thompson, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

David T. Drooz, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: General Statute 62-133.9(d) authorizes the North Carolina Utilities Commission (Commission) to approve an annual rider to the rates of electric public utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) programs. The Commission is also authorized to award incentives to electric utilities for adopting and implementing new DSM/EE programs, including rewards based on the sharing of savings achieved by the programs. Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric utility to establish an annual DSM/EE rider to recover the reasonable and prudent costs incurred for adopting and implementing new DSM/EE measures previously approved by the Commission pursuant to Commission Rule R8-68. Under Commission Rule R8-69, such rider consists of the utility's forecasted cost during the rate period, similarly forecasted performance incentives (including net lost revenues (NLR)) as allowed by the Commission, and an experience modification factor (EMF) rider to collect the difference between the utility's actual reasonable and prudent costs and incentives incurred and earned during the test period and the actual revenues realized during the test period under the DSM/EE rider (based on previous forecasts) then in effect.

Docket No. E-2, Sub 1070

Pursuant to G.S. 62-133.9 and Commission Rule R8-69, on June 17, 2015, Duke Energy Progress, LLC (DEP or the Company), filed an application and the associated testimony and exhibits of Carolyn T. Miller and Robert P. Evans for the approval of a DSM/EE rider to recover DSM/EE costs and utility incentives forecasted for the rate period of January 1, 2016, through December 31, 2016, including program expenses, amortizations and carrying costs associated with deferred prior period costs, Distribution System Demand Response (DSDR) depreciation and capital costs, NLR, and program and portfolio performance incentives (PPI). In addition, DEP asked for approval of a DSM/EE EMF rider to true-up an under-recovery of its actual DSM/EE costs and utility incentives during the adjusted test period of April 1, 2014, through December 31, 2014.[1]

On June 24, 2015, the Commission issued an Order scheduling a public hearing in this matter for September 15, 2015, immediately following the 9:30 a.m. hearings in Docket Nos. E-2, Subs 1069 and 1071, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice. On September 3, 2015, DEP filed its affidavits of publication indicating that the Company had provided notice in newspapers of general circulation as required by the Commission's June 24, 2015 Order.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

[1] The trued-up DSM/EE costs and utility incentives for the test period months of April through July 2014 were recovered in the Company's 2014 DSM/EE Rider proceeding, pursuant to Commission Rule R8-69(b)(2), and thus do not need to be trued up again in this proceeding.

On June 30, 2015, both the North Carolina Sustainable Energy Association (NCSEA) and the Carolina Utility Customers Association, Inc. (CUCA), filed petitions to intervene, which were granted by Commission orders issued July 7, 2015. On August 31, 2015, both the Southern Alliance for Clean Energy (SACE) and the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed petitions to intervene, which were granted by Commission orders issued September 1, 2015.

On August 31, 2015, SACE filed the testimony of Taylor Allred, its Energy Policy Manager. Also on August 31, 2015, the Public Staff filed the affidavit and exhibits of Michael C. Maness, Assistant Director of the Accounting Division, and the testimony of Jack L. Floyd, Engineer in the Electric Division.

On September 1, 2015, DEP filed a joint motion on behalf of itself, SACE and the Public Staff requesting that all witnesses be excused from testifying and that their prefiled testimony, exhibits, and affidavits be received into the record. On September 3, 2015, the Commission granted that motion.

On September 15, 2015, the hearing was held as scheduled. No public witnesses appeared at the hearing. All pre-filed testimony, exhibits, and affidavits of the parties were accepted into evidence by the Commission.

On October 12, 2015, the Public Staff filed a letter with the Commission stating that the Public Staff had found no exceptions in its audit of the costs of the portfolio of DSM/EE programs of DEP incurred during the 9-month test period ended December 31, 2014.

On October 15, 2015, DEP, SACE and the Public Staff filed a Joint Proposed Order. Also on October 15, 2015, NCSEA filed a letter with the Commission in lieu of a proposed order.

Cost Recovery Mechanism

On June 15, 2009, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required Modifications in DEP's first DSM/EE rider proceeding (Sub 931 Order). In that Order, the Commission approved, with certain modifications, an Agreement and Stipulation of Partial Settlement (Stipulation) between DEP, the Public Staff, Wal-Mart Stores East, LP, and Sam's East, Inc., setting forth the terms and conditions for approval of DSM/EE measures and the annual DSM/EE rider proceedings pursuant to G.S. 62-133.9 and Commission Rules R8-68 and R8-69. The Stipulation included a Cost Recovery and Incentive Mechanism for DSM and EE Programs (Original Mechanism), which was modified by the Commission in its Sub 931 Order and subsequently in its Order Granting Motions for Reconsideration in Part issued on November 25, 2009, in the same docket (Reconsideration Order). The Original Mechanism as approved after reconsideration allows DEP to recover all reasonable and prudent costs incurred and utility incentives earned for adopting and implementing new DSM and EE measures in accordance with G.S. 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Original Mechanism.

On January 20, 2015, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waivers. In that Order, the Commission approved an agreement between DEP, the Public Staff, the Natural Resources Defense Council, and SACE proposing revisions to the Original Mechanism, generally to be effective January 1, 2016 (Revised Mechanism). The Revised Mechanism allows DEP to recover all reasonable and prudent costs incurred and utility incentives earned for adopting and implementing new DSM and EE measures in accordance with G.S. 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Revised Mechanism.

In the present proceeding, based upon DEP's verified application, the affidavits, testimony, and exhibits received into evidence, and the record as a whole, the Commission makes the following

FINDINGS OF FACT

1. DEP is a duly organized limited liability company (LLC)[1] existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North and South Carolina, and is subject to the jurisdiction of the Commission as a public utility. DEP is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.9 and Commission Rule R8-69.

2. The test period is normally a 12-month period; however, to effectuate the transition from the Original Mechanism to the Revised Mechanism the test period for purposes of this proceeding is April 1, 2014, through December 31, 2014.[2]

3. The rate period for purposes of this proceeding is the 12-month period, January 1, 2016, through December 31, 2016.

4. For purposes of this proceeding, DEP has requested approval for the recovery of costs, and utility incentives where applicable, related to the following DSM/EE programs: Distribution System Demand Response; EnergyWise; Commercial, Industrial, and Governmental (CIG) Demand Response; Residential Home Advantage (RHA); Residential Home Energy Improvement; Residential Low Income-Neighborhood Energy Saver; CIG EE (EE for Business); Energy Efficiency Lighting (EEL); Residential Energy Efficiency Benchmarking (REEB), which is also known as My Home Energy Report (MyHER); Residential Appliance Recycling (ARP); Small Business Energy Saver (SBES); Residential New Construction; Multi-Family EE; EE Education; Residential Solar Water Heating; and Residential Compact Fluorescent Light (CFL) Bulb pilot. These programs are eligible for cost and utility incentive recovery, where applicable.

[1] DEP converted from a corporation to a limited liability company on August 1, 2015.

[2] See Footnote 1. As the test period DSM/EE costs and utility incentives for the months of April through July 2014 were already trued-up in the Company's 2014 DSM/EE Rider proceeding pursuant to Commission Rule R8-69(b)(2), the test period DSM/EE costs and utility incentives being trued up in this proceeding are only those for the months of August through December 2014.

5. DEP also requested recovery of incremental administrative and general (A&G) expenses not directly related to specific DSM or EE programs. The level of A&G costs proposed by DEP in this proceeding is reasonable. It is appropriate for DEP to recover these incremental A&G costs over a three-year period pursuant to the Original Mechanism and Revised Mechanism.

6. The evaluation, measurement, and verification (EM&V) analyses and reports prepared by DEP are adequate for purposes of this proceeding, and DEP has appropriately incorporated the results of EM&V into the DSM/EE rider calculations.

7. DEP initially requested the recovery of NLR in the amount of $11,145,963 and PPI in the amount of $5,818,064 in the EMF component of the total DSM/EE Rider, and NLR of $39,637,452 and PPI of $18,429,648 for recovery in the forward-looking, or prospective component of the total Rider. As a result of additional analysis performed by DEP and provided to the Public Staff during the course of the proceeding, the Public Staff recommended a reduction in the prospective PPI to $18,204,469. DEP’s proposed recovery of NLR and PPI, as adjusted by the Public Staff, is consistent with the Original Mechanism and Revised Mechanism, and is appropriate, subject to further review to the extent allowed in the Mechanisms.

8. For purposes of the DSM/EE rider to be set in this proceeding and subject to review in DEP's future DSM/EE rider proceedings, the reasonable and appropriate estimate of the Company’s North Carolina retail DSM/EE program rate period amounts, consisting of its amortized operations and maintenance (O&M) costs, depreciation, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, is $144,127,450, and this is the appropriate amount to use to develop the forward-looking DSM/EE revenue requirement. This amount is the total of DEP’s original recommended $144,352,629 and the Public Staff’s recommended PPI decrement adjustment of $225,179.

9. For purposes of its DSM/EE EMF rider, DEP’s reasonable and prudent North Carolina retail test period costs and incentives (net of the amount previously approved for recovery pursuant to Commission Rule R8-69(b)(2)), consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, are $45,613,753. The reasonable and appropriate amount of test period DSM/EE rider revenues (net of amounts included in the 2014 proceeding pursuant to Commission Rule R8-69(b)(2)) and miscellaneous adjustments to take into consideration in determining the test period DSM/EE under- or over-recovery is $29,807,084. Therefore, the test period revenue requirement, minus the test period revenues collected and miscellaneous adjustments, leaves $15,806,669 as the test period under-collection that is appropriate to use as the DSM/EE EMF revenue requirement in this proceeding.

10. After assignment or allocation to customer classes in accordance with G.S. 62-133.9, Commission Rule R8-69, and the Commission's Sub 931 Order, the revenue requirements for each rate class, excluding the North Carolina Regulatory Fee (NCRF), are as follows:

RATE PERIOD:

Residential	$87,830,871
General Service EE	51,730,095
General Service DSM	4,046,634
Lighting	519,850
Total	$144,127,450

DSM/EE EMF:

Residential	$9,651,741
General Service EE	6,073,951
General Service DSM	54,253
Lighting	26,724
Total	$15,806,669

11. The appropriate and reasonable North Carolina retail class level kilowatt-hours (kWh) sales for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding are:

Rate Class	kWh Sales
Residential	15,715,975,740
General Service	10,467,016,100
Lighting	479,138,946

12. The appropriate DSM/EE EMF billing factors, excluding NCRF, are increments of: 0.061 cents per kWh for the Residential class; 0.058 cents per kWh for the EE component of the General Service classes; 0.001 cents per kWh for the DSM component of the General Service classes, and 0.006 cents per kWh for the Lighting class. These DSM/EE EMF billing factors do not change when the NCRF of 0.148% is included. Customers eligible for opt-out pursuant to G.S. 62-133.9(f) and Commission Rule R8-69(d) who are participating in either only a DSM or only an EE program as of January 1, 2016, are eligible to opt out of the component (either DSM or EE) of the prospective and EMF riders in which they are not participating, effective as of or after that date, provided they follow the opt-out procedures set forth in the statute and Commission Rule, as administered by the Company. The Company shall be allowed in the future to recover any reasonable and appropriately determined actual shortfall in revenues, due to such opt-outs and experienced during the 2016 rate period, in recovery of the EMF revenue requirement established in this proceeding. The extent and timing of that recovery shall be determined by the Commission in future proceedings.

13. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, excluding NCRF, are increments of: 0.559 cents per kilowatt hour (kWh) for the Residential class; 0.494 cents per kWh for the EE component of the General Service classes;

0.039 cents per kWh for the DSM component of the General Service classes; and 0.109 cents per kWh for the Lighting class. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, including NCRF of 0.148%, are increments of: 0.560 cents per kWh for the Residential class; 0.495 cents per kWh for EE component of the General Service classes; 0.039 cents per kWh for the DSM component of the General Service classes; and 0.109 cents per kWh for the Lighting class.

14. In accordance with the Commission's November 25, 2014, Order in Docket No. E-2, Sub 1044 (Sub 1044 Order), DEP has incorporated or will incorporate the recommendations of Public Staff witness Floyd from that proceeding with regard to future EM&V reports relating to DEP's lighting measures, spillover savings, and the Company's REEB program.

15. Also in accordance with the Sub 1044 Order, DEP has reported on the discussions of the Company's Carolinas Energy Efficiency Collaborative (Collaborative) pertaining to opt-out surveys, program modifications recommended by SACE, and customer notifications of forecasted peak demand conditions. DEP will not pursue the proposal for a survey of customers who have opted out of the DSM/EE rider. SACE's recommendations for program modifications and advance notice to customers of forecasted peak demand conditions should be discussed at future meetings of the Collaborative, and the results of those discussions reported to the Commission in the Company's next DSM/EE rider application.

16. In accordance with the Sub 1044 Order requirement that DEP shall monitor the changes in annual ratios of allocations between non-DSDR and DSDR equipment and report the degree of change in its annual DSM/EE rider filing, the Company stated it would provide the first update of the allocation factor in September 2015, and will report to the Commission any changes to the allocation factor in subsequent proceedings.

17. The Commission finds it reasonable for DEP to make best efforts to adjust the timing of its EM&V reports for the program year 2014 to be available by the time of the filing of the 2016 rider proceeding. Additionally, the Company should either include copies of those EM&V reports with its annual DSM/EE rider application, or include in the application a list of the URL website links to the Commission's docket system where such reports are on file.

18. To the extent they are not cost prohibitive, the following recommendations of Public Staff witness Floyd regarding future EM&V reports are reasonable: (i) future EM&V reports should provide more details on how outliers are addressed and categorized with respect to regression modeling used to estimate savings impacts; (ii) with respect to savings for MyHER program that are attributable to other EE programs, they should use the most current savings estimates from the other EE programs, and also for the MyHER program, the reports should exclude any energy savings attributable to the EnergyWise program as it is a DSM program; (iii) with respect to the ARP program's use of secondary metering data for regression modeling, the most recent findings and metering data should be used; and (iv) the EEL program should incorporate any updated attributes from the lighting metering evaluations of either the SBES program or the Energy Efficiency for Business program, as appropriate.

19. The Total Resource Cost (TRC) cost-effectiveness test results for the Residential Home Energy Improvement program are estimated to be below 1.0 for three out of the four years from 2013 through 2016. The Commission finds this is not sufficiently cost-effective, and accepts Public Staff witness Floyd's recommendation that the program should be canceled effective March 31, 2016, unless DEP can demonstrate, prior to that date, how the program will be modified in a manner that will make it cost effective in the long term, or files a statement by March 31, 2016, that the Company expects to submit modifications on or before July 1, 2016, that would bring the cost effectiveness above 1.0 on the TRC test.

20. DEP has not provided TRC results or other cost-effectiveness test scores for the DSDR program since the original program application in 2008. The Commission finds it reasonable to accept Public Staff witness Floyd's recommendation that the Company file TRC results for the DSDR program on or before March 31, 2016. If the TRC score is below 1.0, further proceedings may be appropriate to review the question of ongoing DSDR program cost recovery through the DSM/EE rider.

21. A regulatory fee change became effective on July 1, 2015, and a state income tax rate is scheduled to become effective on January 1, 2016. However, it is not necessary to adjust the DSM/EE rider rates or the DSM/EE EMF rider rates in this proceeding to reflect either of these changes.

22. DEP is not requesting NLR recovery for the DSDR program in the present proceeding, and any question about the starting date for NLR recovery applicable to DSDR may be addressed in future proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-3

The evidence for this finding of fact can be found in DEP's application, the testimony and exhibits of DEP witnesses Miller and Evans, the affidavit of Public Staff witness Maness and the Original Mechanism and the Revised Mechanism.

No party opposed DEP's proposed rate period and test period. The rate period proposed by DEP is consistent with the Revised Mechanism approved by the Commission. The modified test period proposed by DEP is appropriate for transition from the Original Mechanism to the Revised Mechanism. The proposed rate period and test period are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact can be found in DEP's application, the testimony and exhibits of DEP witness Miller, the testimony of Public Staff witness Floyd, and various Commission orders in program approval dockets.

The direct testimony of DEP witness Miller and her Exhibit 1 list the DSM/EE programs for which the Company is requesting cost recovery, and incentives where applicable, in this proceeding. Those programs are: DSDR; EnergyWise; CIG Demand Response; RHA; Residential Home Energy Improvement; Residential Low Income-Neighborhood Energy Saver; CIG EE; EEL; REEB, (also known as MyHER); ARP; SBES; Residential New Construction; Multi-Family EE; EE Education; Residential Solar Water pilot; and Residential CFL Bulb Pilot.

In his testimony, Public Staff witness Floyd listed these DSM/EE programs and noted that each of these programs has previously received Commission approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under G.S. 62-133.9. He noted that the RHA, Residential Solar Hot Water pilot, and Residential CFL Bulb pilot programs had been canceled but were still appropriate for cost recovery in this proceeding due to ongoing amortization of past costs.

Accordingly, because each of the programs listed by witnesses Miller and Floyd has received Commission approval as a new DSM or EE program (or pilot), each is, consequently, eligible for cost recovery in this proceeding under G.S. 62-133.9.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact can be found in DEP witness Miller and Evan's testimony.

The appropriate A&G amounts for use in the development of the EMF and rate periods were provided by DEP witness Miller. In her Exhibit No. 1, witness Miller provided $1,741,261 as the test period A&G cost appropriate for use in the development of DEP's EMF rate and $3,078,909 as the estimated 2016 A&G cost appropriate for use in the development of DEP's prospective DSM/EE rate. Additionally Company witness Miller proposed decrement EMF adjustments of approximately $700,000 to correct A&G costs that had been included in the 2014 DSM/EE rider proceeding.

In prior proceedings, the Commission sought particular information about General Education and Awareness (GEA) expenditures that were part of A&G costs. DEP witness Evans noted that presently there are no unassigned GEA costs. The GEA activities are program-specific and thus not part of incremental A&G costs.

No party opposed DEP's incremental A&G costs.

Therefore, based on all evidence in the record, the Commission finds and concludes that the expenditures are reasonable and prudent and further concludes that it is appropriate for DEP to recover these incremental A&G costs over a three-year period pursuant to the Original Mechanism and Revised Mechanism.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact can be found in the testimony of DEP witness Evans and the testimony of Public Staff witness Floyd.

Witness Evans testified that DEP's third party consultant, Navigant, completed its assessment for the 2013 vintage of the EEL, ARP, SBES, and CIG EE programs. In addition, Navigant completed its assessment for the REEB program in both 2013 and through the program's closure in mid-2014.

Public Staff witness Floyd testified that the Public Staff had reviewed the EM&V reports filed by DEP prior to July 1, 2015. He identified the programs evaluated, their docket numbers, and the vintage year completed as follows: REEB, Sub 989, 2013; EnergyWise, Sub 927, Summer 2013; SBES, Sub 1022, 2013; EEL, Sub 950, 2013; Neighborhood Energy Save, Sub 952, 2013; and ARP, Sub 970, 2013.

No party objected to DEP's EM&V results for use in the present proceeding. Witness Floyd noted that other EM&V reports were filed after July 1, 2015, but were not incorporated into the DSM/EE savings calculations used in the present docket and that the savings related to those vintage years will be trued up in the next DEP DSM/EE rider proceeding.

Using the EM&V reports completed prior to July 1, 2015, DEP reevaluated cost-effectiveness for these program vintages under both the TRC test and the Utility Cost Test (UCT). Cost-effectiveness tests are first used to evaluate a DSM or EE program as a resource option, and then again later to reevaluate the PPI. With a few exceptions, programs or measures with a TRC of less than 1.0 at the time of the cost recovery proceeding are ineligible for a PPI. The levelized PPIs for the program vintages were recalculated using revised cost-effectiveness results resulting from EM&V. In addition to the changes in PPI amounts, EM&V-based impacts to the Company's NLR values were also recognized.

Witness Evans further stated that he used the updated EM&V reports to recalculate PPI values and associated carrying costs, determining that there had been a past under-collection of $190,380. That amount is reflected in Miller Exhibit 7 as EMF-related adjustments.

Public Staff witness Floyd testified that he had observed the operation of the database DEP uses to track the capacity and energy savings data of its DSM/EE programs, and he had confirmed through sampling that the data properly flowed into the calculations of net present values (NPV) that serve as the basis for the NLR and PPI calculations. He stated that he tracked the data derived from EM&V as they were incorporated into the database, the NPV calculations and, ultimately, the rider calculation. Witness Floyd affirmed that DEP was appropriately incorporating the results of EM&V into the DSM/EE rider calculations.

Based upon the testimony and evidence above and in the record of this proceeding, the Commission finds the net energy and capacity savings derived from the EM&V to be reasonable and appropriate. Further, the Commission concludes that DEP is appropriately incorporating the results of EM&V into the DSM/EE rider calculations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-13

The evidence for these findings of fact can be found in the testimony and exhibits of DEP witness Miller and the affidavit and exhibits of Public Staff witness Maness. The Commission also takes notice of the statement made at the hearing by Public Staff counsel regarding the ongoing audit of DSM/EE program costs and the procedure under which adjustments, if any, may be addressed in the future.

In DEP witness Miller's testimony and exhibits, she calculated DEP's North Carolina retail adjusted test period (August through December 2014) DSM/EE NLR as $11,145,963 and its adjusted test period PPI as $5,818,064. She calculated DEP's estimated North Carolina retail rate period (January through December 2016) DSM/EE NLR as $39,637,452 and the comparable PPI as $18,429,648.

DEP witness Miller calculated DEP's total North Carolina retail adjusted test period costs and utility incentives, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI to be $45,613,753. Witness Miller's testimony and exhibits also indicated that the amount of adjusted test period DSM/EE rider revenues and miscellaneous adjustments to take into consideration in determining the adjusted test period DSM/EE under- or over-recovery is $29,807,084. Therefore, the aggregate DSM/EE under-recovery recommended by DEP for purposes of this proceeding is $15,806,669.

Witness Miller also calculated DEP's estimate of its North Carolina retail DSM/EE program rate period amounts, consisting of its amortized operations and maintenance (O&M) costs, depreciation, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, as $144,352,629.

According to the testimony and exhibits of DEP witness Miller, after assignment or allocation to customer classes in accordance with G.S. 62-133.9, Commission Rule R8-69, and the Commission Orders in Docket No. E-2, Sub 931, the revenue requirements for each class, excluding NCRF, are as follows:

RATE PERIOD:

Residential	$88,019,354	($74,541,595 EE + $13,477,759 DSM)
General Service	55,813,425	($51,730,095 EE + $4,083,330 DSM)
Lighting	519,850	($519,850 EE + $0 DSM)
Total	$144,352,629	

DSM/EE EMF:

Residential	$9,651,741	($8,642,353 EE + $1,009,388 DSM)
General Service	6,128,204	($6,073,951 EE + $54,253 DSM)
Lighting	26,724	($26,724 EE + $0 DSM)
Total	$15,806,669	

Witness Miller's exhibits also set forth the North Carolina retail class level kWh sales that DEP believes are appropriate and reasonable for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding. She adjusted the kWh sales to exclude estimated sales to customers who have opted out of participation in DEP's DSM/EE programs. The adjusted sales amounts are as follows:

Residential class – 15,715,975,740 kWh; General Service classes – 10,467,016,100 kWh; and Lighting class – 479,138,946 kWh.

Witness Miller calculated the DSM/EE billing factors without NCRF as follows:

Rate Class	DSM Rate ($/kWh)	EE Rate ($/kWh)	DSM EMF ($/kWh)	EE EMF Rate ($/kWh)	DSM/EE Annual Rider ($/kWh)
Residential	.00086	.00474	.00006	.00055	.00621
General Service EE		.00494		.00058	.00552
General Service DSM	.00039		.00001		.00040
Lighting		.00109		.00006	.00115

Adding the NCRF increased the Residential EE rate to $0.00475/kWh, the combined Residential DSM/EE and DSM/EE EMF rider rate to $0.00622/kWh, the General Service EE rate to $0.00495/kWh, and the combined General Service EE and EE EMF rider rate to $0.00553/kWh.

Public Staff witness Maness indicated that the focus of the Public Staff's investigation of DEP's filing in this proceeding was on whether the proposed DSM/EE riders were calculated in accordance with the Original and Revised Mechanisms, as applicable, and otherwise adhered to sound ratemaking concepts and principles. The Public Staff's investigation included a review of the Company's filing and relevant prior Commission proceedings and orders, and the selection and review of a sample of source documentation for test period costs included by the Company for recovery.

Witness Maness testified that his investigation of DEP's filing indicated that the Company generally has calculated the proposed riders in accordance with the methods set forth in the approved Mechanisms, as applicable, for recovery of costs, NLR, and the PPI. Witness Maness noted that DEP had discovered an error in the 2015 vintage year avoided transmission and distribution cost for the CIG Demand Response and EnergyWise programs. This affected the calculation of rate period PPI for those programs, and witness Maness made a corresponding adjustment that reduced the prospective PPI by $225,179, to $18,204,469. The impact of the corrections was large enough to reduce the Residential class DSM/EE billing rate slightly, but not large enough to affect the General Service DSM billing rate. The billing factor for the Residential DSM/EE rate decreased by 0.001 cents/kWh (including NCRF), to 0.621 cents/kWh. No party objected to the adjustment.

Witness Maness testified that the Public Staff was continuing to review portions of the Company's calculations and responses to data requests. In his affidavit, Public Staff witness Maness noted that if any adjustments were identified by the Public Staff in its ongoing audit of DSM/EE costs and agreed to by DEP, the adjustments would be recorded in the 2015 DSM/EE deferral account and in the absence of agreement, any proposed adjustments would be submitted to the Commission for decision in the 2016 DSM/EE rider proceeding. On October 12, 2015, the Public Staff filed a letter with the Commission stating that the audit was complete and that no exceptions were found during the course of its audit.

With respect to DEP's proposed recovery of NLR and PPI, as adjusted by witness Maness for the rate period PPI for CIG DR and EnergyWise, the Commission notes that no party opposed such recovery. The Commission finds that such proposed recovery is consistent with the Commission's Sub 931 Order, as modified by the Reconsideration Order, and that NLR and PPI are appropriate for recovery in this proceeding, with the prospective and rate period costs subject to further review in DEP's future annual DSM/EE rider proceedings. The Commission concludes that DEP has complied with G.S. 62-133.9, Commission Rule R8-69, and the Sub 931 Order, as modified by the Reconsideration Order, with regard to calculating costs and incentives for the test and rate periods at issue in this proceeding.

In its letter filed with the Commission in lieu of a Proposed Order, NCSEA stated that NCSEA does not challenge the reasonableness or prudence of any costs for which DEP seeks recovery in its DSM/EE application.

Therefore, the Commission concludes that for purposes of the DSM/EE EMF rider to be set in this proceeding, DEP's reasonable and prudent North Carolina retail test period costs and incentives, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, are $45,613,753. The reasonable and appropriate amount of test period DSM/EE rider revenues and adjustments to take into consideration in determining the test year and prospective period DSM/EE under- or over-recovery is $29,807,084. Therefore, the aggregate DSM/EE under-recovery for purposes of this proceeding is $15,806,669 ($45,613,753 - $29,807,084).

Furthermore, the Commission finds that the appropriate and reasonable North Carolina retail class level kWh sales for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding are as follows: Residential class – 15,715,975,740; General Service classes - 10,467,016,100; and Lighting class - 479,138,946.

For purposes of the DSM/EE rider to be set in this proceeding, and subject to review in DEP's future DSM/EE rider proceedings, the Commission concludes that DEP's reasonable and appropriate estimate of its North Carolina retail DSM/EE program rate period amounts, consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, after incorporation of the PPI adjustment recommended by the Public Staff, is $144,127,450, and that this is the appropriate amount to use to develop the DSM/EE revenue requirement.

With regard to the revenue requirements per class, the Commission concludes that after assignment or allocation to customer classes in accordance with G.S. 62 133.9, Commission Rule R8-69, and the Orders in Docket No. E-2, Sub 931, the revenue requirements for each class, excluding NCRF, are as follows:

RATE PERIOD:

Residential	$87,830,871
General Service	55,776,729
Lighting	519,850
Total	$144,127,450

DSM/EE EMF:

Residential	$9,651,741
General Service	6,128,204
Lighting	26,724
Total	$15,806,669

Based on the testimony and exhibits of witness Miller and the affidavit and exhibits of witness Maness, and the entire record in this proceeding, the Commission finds and concludes that the DSM/EE EMF billing factors as proposed by DEP witness Miller are appropriate. The Commission further concludes that the forward-looking DSM/EE rates as proposed by DEP witness Miller and adjusted by Public Staff witness Maness to be charged during the rate period for the Residential, General Service, and Lighting rate schedules are appropriate. All of these factors are set forth on Maness Exhibit II. The Commission notes that pursuant to the Revised Mechanism DEP has proposed that its combined General Service DSM and DSM EMF billing factor, and its combined General Service EE and EE EMF billing factor, be available to General Service customers for measures and programs implemented on and after January 1, 2016. The

Commission agrees with and approves this approach. Furthermore, consistent with the Commission's decisions in Docket No. E-7, Sub 938, the Commission hereby concludes that customers eligible for opt-out pursuant to G.S. 62-133.9(f) and Commission Rule R8-69(d) who are participating in either only a DSM or only an EE program as of January 1, 2016, are eligible to opt out of the component (either DSM or EE) of the prospective and EMF riders in which they are not participating, effective as of or after that date, provided they follow the opt-out procedures set forth in the statute and Commission Rule, as administered by the Company.

The Commission recognizes that in its calculation of the EMF in this proceeding DEP did not anticipate any such single-category opt-outs in its calculation of North Carolina retail kWh sales. Therefore, the Commission concludes that the Company shall be allowed in the future to recover any reasonable and appropriately determined actual shortfall in revenues, due to such opt-outs, experienced during the 2016 rate period in recovery of the EMF revenue requirement established in this proceeding. The extent and timing of that recovery shall be determined by the Commission in future proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-16

The evidence for these findings of fact can be found in the testimony of DEP witness Evans, Public Staff witness Floyd, and SACE witness Allred, as well as the record in Docket No. E-2 Sub 1044.

In the Sub 1044 Order, the Commission ordered the Company to incorporate the recommendations of witness Floyd with regard to future EM&V for certain programs. Specifically, for the EM&V of lighting measures, witness Floyd recommended that DEP include in future reports a discussion of the impacts of the Energy Independence and Security Act of 2007 and other relevant regulatory mandates on the calculations of measure impacts and the baseline measures used in those calculations. Witness Floyd further recommended that future evaluations include post-installation on-site verification of a sample of projects for which spillover savings are claimed, if spillover savings exceed 20% of verified gross savings and are estimated to produce at least 500,000 kWh per year savings. Finally, he recommended that future evaluations for the REEB Program continue to include an investigation of the potential for double-counting savings associated with CFL or other lighting measure installations. In the present proceeding, Witness Evans testified that DEP has adopted witness Floyd's recommendations from last year's DSM/EE rider proceeding. Public Staff witness Floyd concurred that DEP had incorporated his recommendations where applicable in the EM&V reports reviewed in the present case, and that he understood DEP's evaluation consultant would also incorporate his recommendations in future EM&V reports. The Commission therefore concludes that DEP has met these requirements from the Sub 1044 Order and should continue to incorporate those recommendations from witness Floyd.

Also in the Sub 1044 Order, the Commission required that DEP report the results and any conclusions or recommendations regarding the Collaborative's discussions scheduled to begin in the third and fourth quarter of 2014 pertaining to surveys of customers who have opted-out of DEP's portfolio of DSM or EE programs, program modifications recommended by SACE, and customer notification of forecasted peak demand conditions. Witness Evans testified that the Collaborative discussed surveying opt-out customers to assess what EE measures they had implemented, but some stakeholders opposed such a survey. He stated that in the absence of consensus, the Company decided not to conduct a survey of customers that had opted-out. Witness Evans further noted that suggestions by SACE for program modifications had been discussed in the Collaborative, and that these items warranted further discussion in future meetings. He stated that the possibility of peak notifications to customers would be discussed in the third quarter (2015) Collaborative meeting. In his testimony, SACE witness Allred offered several additional ideas for program modifications aimed at increasing DEP's energy savings, which should be addressed and discussed in future Collaborative meetings.

Based on the foregoing and all the evidence in the record in this proceeding, the Commission concludes that DEP has taken reasonable actions to comply with these requirements from the Sub 1044 Order, and that it should proceed to discuss SACE's proposals for program modifications and peak notifications to customers in future Collaborative meetings. DEP should report on those discussions as part of its next DSM/EE rider application.

Additionally, the Sub 1044 Order provided that DEP should monitor the changes in annual ratios of allocations between non-DSDR and DSDR equipment and report the degree of change in its annual DSM/EE rider filing. In his testimony, witness Evans informed the Commission that the process to monitor allocation changes was being put in place from July through September, and that updated allocation factors would be calculated in September 2015. He further stated the DEP would report any changes to the Commission in subsequent proceedings. Therefore, based on the information provided by DEP witness Evans regarding this matter, the Commission finds and concludes that DEP should file reports of changes to its allocations between non-DSDR and DSDR equipment in future proceedings and provide the Public Staff with information on any changes to the allocation factor as they become available.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence for this finding of fact can be found in the testimony of SACE witness Allred.

SACE witness Allred observed that DEP's EM&V reports are filed in the program approval dockets instead of the annual cost recovery rider docket at different times during the year, and that not all the EM&V reports for the vintage year 2013 were available when the Company filed its application in the present proceeding. He recommended that in the future DEP should adjust the timing of the filing of its EM&V reports so they are all available by the time of each rider proceeding for the year prior to the test period, and should include copies of the EM&V reports in its rider applications. Witness Allred stated that this would help improve transparency. No other party commented on this proposal.

The Commission concludes that DEP should, to the extent possible, adjust the timing of its EM&V reports so that all reports for program year 2014 are available by the time of the filing of the Company's 2016 rider proceeding. Furthermore, the Company should discuss the timing of future EM&V reports in the Collaborative, and the Company should include copies of those EM&V reports and/or a web link to each filed report with its annual DSM/EE rider application.

The Commission notes that in other DSM and EE program approval proceedings filed by DEP and Duke Energy Carolinas, LLC (DEC), the Commission has observed similarities between the programs of both companies and the proposed EM&V. While the Commission encourages both companies to coordinate their EM&V work and schedules, particularly for programs both companies offer that are similar in design and measures offered, to minimize the costs of EM&V for both companies, the Commission recognizes that the timing of EM&V work and the filing of EM&V reports may not always be coordinated with the test year period of either company. However, to the extent EM&V reports can be coordinated, DEP and DEC should coordinate their EM&V reporting with the test year period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding of fact can be found in the testimony of Public Staff witness Floyd.

The recommendations of Public Staff witness Floyd with regard to future EM&V reports, as summarized in Finding of Fact No. 18, were not opposed by any other party. The Commission finds and concludes that DEP should comply with those recommendations to the extent they are not cost prohibitive.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence for this finding of fact can be found in the testimony of Public Staff witness Floyd and SACE witness Allred.

Public Staff witness Floyd testified that the Residential Home Energy Improvement program had TRC results of 0.8 for 2013, an estimated 0.8 for 2014, an estimated 1.1 for 2015, and an estimated 0.9 for 2016. He recommended that unless DEP can demonstrate by March 31, 2016, how the program can remain cost-effective in the long term, the program should be canceled by March 31, 2016. No other party commented on his recommendation, although SACE witness Allred also made note of the decline in the program's cost-effectiveness. The Commission notes that G.S. 62 133.9(c) requires electric power suppliers to submit cost-effective DSM and EE programs to the Commission for approval if incentives are sought. The Commission's Rule R8-69 for annual riders implicitly recognizes the relevance of cost-effectiveness by requiring the filing of total expenses and avoided costs (benefits). Likewise, Paragraph 22 of the Revised Mechanism provides that in each annual DSM/EE cost recovery filing, DEP shall provide prospective cost-effectiveness test evaluations for each of its approved DSM and EE programs, and discuss whether the results indicate that any of the programs should be modified or discontinued.

The Commission takes notice that the Residential Home Energy Improvement program has had a TRC below 1.0 for three out of four years, and, thus, is not cost-effective. Therefore, the Commission finds and concludes that the Residential Home Energy Improvement program should be canceled effective March 31, 2016, unless DEP can show that the program will achieve cost-effectiveness in future years or files a statement by March 31, 2016, that the Company expects to submit modifications on or before July 1, 2016, that would bring the cost-effectiveness above 1.0 on the TRC test.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence for this finding of fact can be found in the testimony of Public Staff witness Floyd.

Public Staff witness Floyd noted that DEP has not provided a cost-effectiveness evaluation of DSDR since the projected cost-effectiveness test scores in the original DSDR program application in 2008. He testified that DSDR was supposed to be in operation by 2012, that it has been used on multiple occasions since early 2014, and that DEP now has more than a year of data for DSDR since the program became fully operational in June of 2014. Accordingly, witness Floyd recommended that DEP be required to provide TRC results for the DSDR program no later than March 31, 2016, and that DSDR costs continue to be recovered through the DSM/EE rider if the EM&V results show a TRC greater than 1.0. No other party responded to witness Floyd's recommendation.

The Commission concludes that because over $241 million has been spent on DSDR and is being recovered from ratepayers, and because the Revised Mechanism is predicated on the recovery of costs and incentives for cost-effective programs, it is incumbent upon DEP to show the cost-effectiveness of the DSDR program. The Commission concludes that witness Floyd's recommendation is consistent with the statutory intent for DSM/EE programs, with Commission Rule R8-69, and with the Revised Mechanism. Therefore, DEP should provide an EM&V report on DSDR, including TRC test results, on or before March 31, 2016. If the TRC result is greater than 1.0, then ongoing cost recovery of DSDR through the DSM/EE rider is appropriate; otherwise, cost recovery through the rider may be reviewed.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence for this finding of fact can be found in the affidavit of Public Staff witness Maness.

Public Staff witness Maness stated in his affidavit that the NCRF changed from 0.135% to 0.148% of North Carolina retail revenues effective July 1, 2015. He determined that the change would not impact the cents per kWh DSM/EE or DSM/EE EMF riders. Witness Maness also stated that the state income tax rate is scheduled to decrease to 4% effective January 1, 2016, which could affect the 2016 vintage DSM/EE revenue requirement. He proposed that the rate period revenue requirement be subject to true-up in future DSM/EE EMF riders to reflect any tax change. No other party commented on these changes. Based on the foregoing, the Commission finds and concludes that no adjustment to the rider rates is necessary in this proceeding due to the change in the NCRF and that any adjustment for the applicable state income tax change can be addressed in future DSM/EE EMF riders.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence for this finding of fact can be found in the affidavit of Public Staff witness Maness and testimony of DEP witness Evans.

Public Staff witness Maness noted in his affidavit that DEP considered June 1, 2014, as the "in-service date" for DSDR. He stated that the Public Staff considers the beginning date for DSDR to be an open topic to be evaluated in future cases. He noted that the beginning date of a program is also the date that the 36-month period applicable to NLR recovery begins. However, DEP witness Evans testified that the Company is not requesting recovery of NLR in the present proceeding. Therefore, the Commission concludes that the issue of the appropriate in-service date of DSDR should be addressed when, or if, DEP requests recovery of NLR for DSDR in a future rider proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the appropriate DSM/EE EMF billing factors, excluding NCRF, for the Residential, General Service, and Lighting rate classes are increments of: 0.061 cents per kWh for the Residential class; 0.058 cents per kWh for the EE component of General Service classes; 0.001 cents per kWh for the DSM component of General Service classes, and 0.006 cents per kWh for the Lighting class. These DSM/EE EMF billing factors do not change when the NCRF is included.

2. That the appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period for the Residential, General Service, and Lighting rate classes (excluding NCRF) are increments of 0.559 cents per kWh for the Residential class; 0.0494 cents per kWh for the EE component of General Service classes; 0.039 cents per kWh for the DSM component of General Service classes; and 0.109 cents per kWh for the Lighting class. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, including NCRF of 0.148%, are increments of: 0.560 cents per kWh for the Residential class; 0.495 cents per kWh for the EE component of the General Service classes; 0.039 cents per kWh for the DSM component of the General Service classes; and 0.109 cents per kWh for the Lighting class.

3. That the appropriate total DSM/EE annual riders including the DSM/EE rate and the DSM/EE EMF rate (including NCRF of 0.148%) for the Residential, General Service, and Lighting rate classes are increments of 0.621 cents per kWh for the Residential class, 0.553 cents per kWh for the EE portion of the General Service classes, 0.040 cents per kWh for the DSM portion of the General Service classes, and 0.115 cents per kWh for the Lighting class.

4. That DEP shall file, within 10 days of the date of this Order, appropriate rate schedules and riders with the Commission in order to implement these adjustments. Such rates are to be effective for service rendered on and after January 1, 2016.

5. That DEP shall work with the Public Staff to prepare a joint proposed Notice to Customers of the rate adjustments ordered by the Commission in Docket Nos. E-2 Sub 1023, 1069,

1070, 1071, and 1088, and the Company shall file such proposed notice for Commission approval as soon as practicable.

6. That as part of its 2016 DSM/EE rider filing DEP shall report the results of the Collaborative's discussions pertaining to program modifications recommended by SACE and customer notifications of forecasted peak demand conditions.

7. That the issues raised in witness Allred's testimony shall be discussed in the DEP Collaborative with the results of such discussions to be reported in the Company's application in the next DSM/EE rider proceeding.

8. That DEP shall file all changes in annual ratios of allocations between non-DSDR and DSDR equipment, report the degree of change in its annual DSM/EE rider filings, and provide such changes to the Public Staff as they become available.

9. That the Residential Home Energy Improvement program shall be canceled effective March 31, 2016, unless DEP can demonstrate how the program can be made cost-effective in the long term or files a statement by March 31, 2016, that the Company expects to submit modifications on or before July 1, 2016, that would bring the cost-effectiveness above 1.0 on the TRC test.

10. That with regard to the DSDR program, DEP shall conduct EM&V and provide TRC results to the Commission on or before March 31, 2016.

11. That DEP shall implement the recommendations of Public Staff witness Floyd regarding future EM&V reports.

12. That to the extent possible, and in coordination with DEC for EM&V that may be used by both companies, DEP shall adjust the timing of its EM&V reports as appropriate, so they are all available by the time of each rider proceeding for the year prior to the test period. DEP shall include copies of or web links to those filed EM&V reports in its annual DSM/EE rider application.

13. That customers eligible for opt-out pursuant to G.S. 62-133.9(f) and Commission Rule R8-69(d) who are participating in either only a DSM or only an EE program as of January 1, 2016, shall be eligible to opt-out of the component (either DSM or EE) of the prospective and EMF riders in which they are not participating, effective as of or after that date, provided they follow the opt-out procedures set forth in the statute and Rule, as administered by the Company, and that the Company shall be allowed in the future to recover any reasonable and appropriately determined actual shortfall in revenues, due to such opt-outs and experienced during the 2016 rate period, in recovery of the EMF revenue requirement established in this proceeding. The extent and timing of that recovery shall be determined by the Commission in future proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th ___ day of November, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

DOCKET NO. E-2, SUB 1071
DOCKET NO. E-7, SUB 1074
DOCKET NO. E-22, SUB 525
DOCKET NO. E-100, SUB 113
DOCKET NO. E-100, SUB 121
DOCKET NO. E-100, SUB 145

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1071

In the Matter of
Application of Duke Energy Progress, LLC, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to G.S. 62-133.8 and Commission Rule R8-67

DOCKET NO. E-7, SUB 1074

In the Matter of
Application of Duke Energy Carolinas, LLC, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to 62-133.8 and Commission Rule R8-67

DOCKET NO. E-22, SUB 525

In the Matter of
Application of Virginia Electric and Power, d/b/a Dominion North Carolina Power, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to G.S. 62-133.8 and Commission Rule R8-67

DOCKET NO. E-100, SUB 113

In the Matter of
Rulemaking Proceeding to Implement Session Law 2007-397

ORDER ADDRESSING POULTRY COMPLIANCE SHORTFALL AND REQUESTING COMMENTS ON NEW ALLOCATION METHOD

DOCKET NO. E-100, SUB 121	)
	)
In the Matter of	)
Implementing a Tracking System for	)
Renewable Energy Certificates Pursuant	)
to Session Law 2007-397	)
	)
DOCKET NO. E-100, SUB 145	)
	)
In the Matter of	)
2015 REPS Compliance Plans and 2014	)
REPS Compliance Reports	)

BY THE COMMISSION: On September 21, 2015, the Commission issued an Order Requesting Comments on Options for Addressing Poultry REC Shortfall in the above-captioned dockets. The Order stated that on September 16, 2015, the Administrator of the North Carolina Renewable Energy Tracking System (NC-RETS) filed a letter with the Commission explaining that the 2013 retail sales for some electric power suppliers were corrected well after the June 1, 2014 deadline,[1] some as recently as August of 2015. This caused NC-RETS's software to re-allocate the 170,000-MWh 2014 poultry waste resource obligation among electric power suppliers. Some electric power suppliers had already submitted their 2014 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance to the Commission when this re-allocation occurred. According to the letter, North Carolina's electric power suppliers, in the aggregate, were 599 MWh short of the 2014 poultry waste resource obligation due to the re-allocation.

The Order requested comments on these questions:

1) What actions, if any, the Commission should take to address the apparent 599 MWh short-fall in the electric power suppliers' aggregate 2014 poultry waste resource requirement, including the option of rolling the shortfall into the 2015 compliance year;

2) What changes to the Commission's rules or the NC-RETS software are necessary to prevent a similar occurrence in the future; and

3) Whether an independent audit of the NC-RETS system is advisable.

Comments addressing these questions were filed October 2, 2015, by: Dominion North Carolina Power (Dominion); jointly by North Carolina Eastern Municipal Power Agency and North Carolina Municipal Power Agency Number 1 (collectively the Agencies); jointly by Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), (collectively Duke); and the Public Staff.

[1] See Commission Rule R8-67(h)(11).

COMMENTS BY THE PARTIES

As to the question of what actions, if any, the Commission should take to address the apparent 599 MWh short-fall in the electric power suppliers' aggregate 2014 poultry waste resource requirement, Dominion stated that it had already updated its 2014 REPS compliance so that the poultry RECs in its 2014 compliance sub-account in NC-RETS is accurate[1] "[Dominion] is not responsible for any portion of the 599 MWh shortfall...." Dominion recommended that each electric power supplier be required to notify the Commission by November 1, 2015, as to whether it has updated its 2014 poultry compliance or whether it elects to roll any shortfall into the 2015 REPS compliance year. If an electric power supplier elects to update its 2014 compliance, the supplier should not be required to refile its 2014 REPS compliance report. Instead, the power supplier would verify that it had submitted the required number of poultry RECS into its 2014 compliance sub-account.

The Agencies stated that:

> Based on the data set forth in APX's [the NC-RETS administrator's] letter to the Commission, it appears that [Duke] and [TVA] moved slightly less poultry RECs into their respective 2014 compliance sub-accounts than they needed to, based on the revised data as to the total retail electric sales [of] all electric suppliers, with the total differential being 599 poultry RECs.

The Agencies stated that they believe there is an adequate number of poultry RECs available to comply with the 170,000 MWh poultry REC requirement for 2014, so there is no need to roll this "shortfall" into the 2015 compliance year.

> In the event that [Duke] and TVA do not have a total of 599 additional poultry RECs to retire for 2014, then the Power Agencies are willing to, in effect, "advance" 599 poultry RECs on their behalf to maintain compliance with the poultry waste set-aside requirement. In that event, then for purposes of compliance with the poultry waste set-aside requirement in future years the Power Agencies would be "credited" with the excess poultry RECs which they retired for 2014.

[1] On October 14, 2015, Dominion submitted testimony in Docket No. E-22, Sub 525 confirming that it had substituted 27 poultry RECs for 27 general RECs in its 2014 compliance sub-account.

Duke stated that its poultry REC "shortfall" based on the revised poultry obligation is 574 poultry RECs, which is the vast majority of the shortfall. "Although the Companies have sufficient eligible REC inventories available for retirement now to make up the combined shortfall for DEC and DEP, the Companies recommend rolling [this amount] into the power suppliers' 2015 poultry waste resource obligations." Duke stated that this approach would be simpler because there would be no confusion regarding the 2014 REPS compliance reports that have already been filed,[1] and there would be no need for the Commission to reject compliance sub-accounts in NC-RETS, which would then need to be adjusted by the power suppliers and re-submitted for approval.

The Public Staff stated that some electric power suppliers were already adjusting their 2014 compliance sub-accounts to ensure that the correct number of poultry RECs were submitted.

> To the extent an electric power supplier has already submitted its RECs for compliance purposes based on an earlier allocation of the poultry waste resource obligation, it is appropriate for the Commission to allow those parties to either submit additional poultry RECs towards their 2014 compliance, or in the event the party does currently not have sufficient poultry RECs banked, to allow that shortfall to carry forward to the next compliance year. If a party has retired more RECs than its current allocation, the NC-RETS administrator should "un-retire" those excess RECs to allow them to be used for future compliance.

The second issue raised in the Commission's Order is whether changes should be made to the Commission's rules or the NC-RETS software in order to prevent a similar occurrence in the future.

Commission Rule R8-67(h)(11) states:

> ... <u>Each electric power supplier, or its utility compliance aggregator, shall</u>, within 60 days of NC-RETS beginning operations, and <u>by June 1 of each subsequent year</u>, enter its previous year's retail electricity sales into NC-RETS, which sales will be used by NC-RETS to calculate each electric power supplier's REPS obligations and NC-RETS charges. ... [Emphasis added.]

[1] In the case of DEC, the Commission has approved the Company's 2014 REPS compliance by Order dated July 30, 2015, in Docket No. E-7, Sub 1074. In the case of DEP, that Company's 2014 REPS compliance is pending in Docket No. E-2, Sub 1071.

The Public Staff said that the following sentence should be added to Commission Rule R8-67(h)(11): "After June 1, no electric power supplier may amend its previous year's retail electricity sales without approval of the Commission." Similarly, the Public Staff stated that the Commission should direct the NC-RETS administrator to block any functionality in NC-RETS that would allow power suppliers to change their previous year's retail sales after June 1 of each year.

Dominion stated that it is able to submit its prior year retail sales by June 1, and does not oppose moving this deadline back to September 1. "However, the Company does believe NC-RETS and all other electric power suppliers should have a high level of confidence that an electric power supplier's retail sales data is correct, once filed." Accordingly, Dominion supported the amendment to Commission Rule R8-67(h)(11) that the Public Staff proposed (discussed above).

The Agencies stated that the Commission rules should be revised to move the date for reporting retail sales data to later in the year, preferably to the same date that the compliance report is due (September 1). The Agencies explained that they rely on data that its member power suppliers submit to the Energy Information Administration, U.S. Department of Energy (EIA). The Agencies stated that EIA made changes to its reporting requirements that made it difficult to secure the data from EIA by June 1. For example, the EIA did not open the 2014 submittal window for reporting retail sales data until June 3, 2014, which was two days after the June 1 due date for reporting data to NC-RETS. The EIA's reporting window closed on August 5, after which EIA reviews the data, sometimes resulting in changes. The Agencies stated further that:

> Delaying the date for submission of sales data to NC-RETS to September 1, as recommended by the Power Agencies, would have no adverse impact on the ability of electric suppliers to determine their REPS compliance requirements, as that determination is not made until the following year, e.g., 2013 retail sales data was due to be reported on June 1, 2014, and then was used in 2015 to determine the number of RECs to be retired in August 2015.

The Agencies provided no explanation as to why correct sales data for all of its power suppliers for 2013 was not available until August of 2015.

Duke recommended that electric power suppliers be required to establish their compliance sub-accounts late in a given compliance year (rather than waiting until the subsequent year when compliance is documented to the Commission), and that the NC-RETS administrator be tasked with auditing each electric power supplier's retail sales data, comparing the data that is provided by June 1 as required by the Commission's rules, with the data that is provided when the compliance sub-account is established. The administrator should then "investigate and resolve any differences prior to finalizing the poultry waste resource obligation for each electric power supplier on January 1. This process would be complete before the actual retirement of RECs, which occurs during the year following the end of the compliance year."

On the question of whether an independent audit of NC-RETS is needed, Dominion stated that it "believes that NC-RETS is operating effectively and that the time and potential expense associated with such an audit may not be warranted at this time." The Agencies stated that they "see no need for such an audit." Duke stated "that there are no related and inherent NC-RETS system flaws requiring review by an independent auditor." The Public Staff stated that it "does not have any objections to the Commission authorizing an independent audit of the NC-RETS system in order to identify potential issues before they arise and to suggest improvements to the functionality of the system."

DISCUSSION AND CONCLUSIONS

The Commission has considered the comments filed by parties, as well as updated records in NC-RETS, and concludes that there are advantages in resolving the 2014 poultry compliance shortfall issue sooner rather than later. Although Duke did not cause the shortfall in question, the re-allocation nonetheless caused its 2014 poultry obligations to increase somewhat. Since Duke has enough poultry RECs banked to allow it to comply now by adding poultry RECs to its 2014 compliance sub-accounts, the Commission will require it to do so. The Commission will require DEC to add 317 and DEP to add 211 poultry RECs with vintages dated 2014 or earlier to their 2014 REPS compliance sub- accounts.[1] The Commission anticipates that DEC and DEP would also remove a similar number of general RECs from their compliance sub-accounts.

The Commission has already "accepted" DEC's compliance sub-account in NC-RETS, and the RECs have been retired. Therefore, the Commission will instruct the NC-RETS administrator to "un-retire" 334 general RECs, and allow DEC to replace them with poultry RECs, thereby coming into compliance with the poultry requirement as it has been re-allocated.

NC-RETS now shows that some of the smaller electric power suppliers have under-complied by only one poultry REC, while several others have over-complied by a small number of poultry RECs. The Commission will not require adjustments in these cases.

[1] While this matter has been pending the Commission learned that the recent 2013 retail sales data changes had caused NC-RETS to allocate a 170,075-MWh poultry obligation, rather than the required 170,000-MWh obligation, to the electric power suppliers. This error has since been corrected, thereby reducing the poultry REC shortfall.

The Commission is no longer comfortable allowing electric power suppliers to rely on EIA's data procurement timelines, which are subject to change and are not related to the REPS and the Commission's rules. While it might be convenient for the Agencies to piggy-back on the EIA's data reporting requirements, no party has described any barrier preventing the individual municipal power suppliers from reporting their retail sales data to the Agencies directly in time for the Agencies to submit the data to NC-RETS on June 1 each year as the Commission's rules require. In fact, DEC and DEP apparently have no problem securing this data, on time, from the municipal power suppliers for which they act as compliance aggregators.

Part of the Commission's rationale for the June 1 deadline is that each electric power supplier's current year REPS obligation should be defined while there is still time in the current year to acquire the necessary renewable energy/RECs at reasonable cost. If the reporting of retail sales data were moved back to September 1, as the Agencies advocate, electric power suppliers would have to wait until the fourth quarter of the year to have a clear understanding of that year's compliance obligation. Granted, the compliance report is not due to the Commission until the following year (early March for DEC, early June for DEP, early August for Dominion, and early September for all other electric power suppliers). However, the intent of the rule is that the renewable energy, and/or related RECs, be acquired during the compliance year, not after-the-fact or just-in-time for filing the compliance report in the subsequent year.

Based on these concerns, the Commission does not support Duke's proposal whereby electric power suppliers could submit one sales number in June, and a different one in the context of their compliance sub-accounts later in the year, and the NC-RETS administrator would be relied upon to resolve any discrepancies. Under Duke's proposal, electric power suppliers would need to wait until all discrepancies are resolved before they would have certainty regarding their share of the aggregate poultry requirement. While the poultry REC obligation change might have been small in 2014, the aggregate requirement in 2014 was only 170,000 MWh. When the requirement grows to 900,000 MWh as required by G.S. 62-133.8(f) it will be more difficult for electric power suppliers to meet their obligations if there is a delay in allocating the aggregated requirement among them each year.

The Commission finds that the rule change that is proposed by the Public Staff and Dominion (wherein if an electric power supplier wants to change its sales data after June 1 it must first seek permission from the Commission) is unnecessary. The existing rule states that this data is due by June 1; as with other Commission rules, it is implicit that if a regulated entity cannot comply, it must ask the Commission for a waiver. (In this instance, ElectriCities should have requested a waiver before changing its sales numbers, and if a similar situation were to occur in the future, the Commission might consider reallocating the poultry requirement so that any additional burden would fall only on the electric power supplier that requested permission to update its retail sales data.)

This is the first year in which the NC-RETS functionality for allocating the aggregate poultry obligation has been used. The Commission believes that this method is too dynamic in that every electric power supplier's obligation changes whenever one electric power supplier corrects a retail sales data error. The Commission believes it would be preferable to periodically establish an allocation of the poultry obligation, based on historic retail sales, and leave that allocation in place for a period of years. (For example, perhaps each electric power supplier would submit three years of retail sales data to the Commission, and that data would be used to establish a poultry MWh allocation that would remain static for five years, after which the process would be repeated.) The Commission seeks comments on how an allocation that is stable and fair, yet based on each electric power supplier's share of total retail sales, might be accomplished.

Finally, the Commission agrees with the majority of parties who stated that there is no need for an independent audit of NC-RETS at this time.

IT IS, THEREFORE, ORDERED as follows:

1) That DEC and DEP shall work with the NC-RETS administrator to adjust the RECs in their 2014 compliance sub-accounts as discussed in this Order as soon as reasonably possible;

2) That the NC-RETS administrator shall submit a report to the Commission in Docket No. E-7, Sub 1074 and Docket No. E-2, Sub 1071 as to the status of this effort as soon as possible after the adjustments have been completed, but no later than November 6, 2015; and

3) That all parties are invited to provide comments as to alternative methods of allocating the aggregate poultry obligation in the future. Such comments should be filed in Docket No. E-100, Sub 113 by December 30, 2015. Reply comments may be filed by January 29, 2016.

ISSUED BY ORDER OF THE COMMISSION.
This the _19th _ day of October, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

DOCKET NO. E-2, SUB 1071

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Duke Energy Progress, LLC for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to G.S. 62-133.8 and Commission Rule R8-67	)))))	ORDER APPROVING REPS AND REPS EMF RIDER AND 2014 REPS COMPLIANCE

HEARD: Tuesday, September 15, 2015, at 9:43 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Bryan E. Beatty, Presiding; Chairman Edward S. Finley, Jr. and Commissioners Susan W. Rabon, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Duke Energy Progress, LLC:

Kendrick C. Fentress, Associate General Counsel, Duke Energy Corporation, Post Office Box 1551, Raleigh, North Carolina 27602

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 353 E. Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Tim Dodge, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

For the North Carolina Sustainable Energy Association:

Peter Ledford, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

BY THE COMMISSION: On June 17, 2015, Duke Energy Progress, LLC (DEP or the Company, formerly known as Duke Energy Progress, Inc.), filed its annual Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance Report and application seeking an adjustment to its North Carolina retail (NC retail) rates and charges pursuant to G.S. 62-133.8(h) and Commission Rule R8-67.The Commission is required to conduct an annual proceeding for the purpose of determining whether a rider should be established to permit the recovery of the incremental costs incurred to comply with the requirements of G.S. 62-133.8(b), (d) (e) and (f) and to true up any under-recovery or over-recovery of compliance costs. DEP's application was accompanied by the testimony and exhibits of Megan W. Jennings, Renewable Compliance Manager, and Veronica I. Williams, Rates Manager. In its application and pre-filed testimony, DEP sought approval of the proposed REPS rider, which incorporated the Company's proposed adjustments in its NC retail rates.

On June 24, 2015, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice, in which the Commission set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and DEP rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines. DEP subsequently published notice in newspapers of general circulation, as required by the order, and filed proof of publication on September 9, 2015.

On June 30, 2015, petitions to intervene were filed by the North Carolina Sustainable Energy Association (NCSEA) and Carolina Utility Customers Association, Inc. (CUCA). Both of these petitions were granted by the Commission on July 7, 2015. The intervention and participation by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On July 7, 2015, DEP filed revised Exhibit No. 2 of witness Jennings and Exhibits 1, 2, and 4 of witness Williams.

On August 28, 2015, the Public Staff filed the affidavits of Peter Batista, Engineer – Electric Division, and Michelle Boswell, Staff Accountant – Accounting Division. No other party pre-filed testimony in this docket.

On September 4, 2015, DEP and the Public Staff filed a Joint Motion for Witnesses to be Excused from Appearance at the Evidentiary Hearing, which the Commission granted on September 9, 2015.

The matter came on for hearing as scheduled on September 15, 2015. No public witnesses appeared at the hearing.

On September 21, 2015, the Commission issued in this docket its Order Requesting Comments on Options for Addressing Poultry REC Shortfall (Poultry REC Shortfall Order). In the Order, the Commission requested comments on how to address a reported shortfall in the aggregate poultry waste set-aside requirement for 2014. On October 2, 2015, DEP and Duke Energy Carolinas, LLC, filed comments jointly. In addition, ElectriCities of North Carolina, Inc., North Carolina Municipal Power Agency Number 1, and North Carolina Eastern Municipal Power Agency, filed joint comments, and the Public Staff, GreenCo Solutions, Inc., (GreenCo), and Dominion North Carolina Power filed separate comments. The Commission issued a final Order on this matter on October 19, 2015, whereby the Commission ordered DEP to work with the North Carolina Renewable Energy Tracking System (NC-RETS) administrator to adjust the RECs in the NC-RETS 2014 compliance sub-accounts as discussed in the Order as soon as reasonably possible. Further, the Order required the NC-RETS administrator to submit a report to the Commission as to the status of this effort as soon as possible after the adjustments have been completed. The NC-RETS administrator's report was submitted to the Commission on November 6, 2015.

On October 15, 2015, the Public Staff and DEP filed a Joint Proposed Order in the present docket. Also on that date, NCSEA filed a Post-Hearing Brief.

Based upon the foregoing, DEP's verified application, the testimony, exhibits, and revised exhibits received into evidence at the hearing, the records of NC-RETS, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. DEP is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina and South Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEP is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

2. G.S. 62-133.8(h) authorizes an electric power supplier to recover the "incremental costs" of compliance with the REPS requirements through an annual REPS rider. The "incremental costs," as defined in G.S. 62-133.8(h)(1), include the reasonable and prudent costs incurred by an electric power supplier to comply with REPS "that are in excess of the electric supplier's avoided costs." The term "avoided costs" includes both avoided energy costs and avoided capacity costs. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred to purchase unbundled renewable energy certificates (RECs) constitute incremental costs, and have no avoided cost component.

3. The test period and billing period for this proceeding are, respectively, the period from April 1, 2014 through March 31, 2015, and the 12-month period beginning on December 1, 2015 and ending on November 30, 2016.

4. DEP has agreed to provide REPS compliance services, including the procurement of RECs, to the following wholesale entities (Wholesale Customers): the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek, the Town of Winterville, and the Town of Waynesville.

5. DEP has complied with the 2014 general requirement, solar set-aside requirement, and poultry waste set-aside requirement for itself and the Wholesale Customers for which the Company is providing compliance services. Pursuant to the Commission's Order Modifying the Swine Waste Set-Aside Requirement and Providing Other Relief in Docket No. E-100, Sub 113, issued November 13, 2014 (2014 Relief Order), the Commission delayed the swine waste set-aside requirement for one year.

6. DEP's annual REPS Compliance Report filed pursuant to Commission Rule R8-67(c) demonstrates that DEP is in compliance with G.S. 62-133.8(b) for the test period.

DEP projects that the Company will comply with the general and solar requirements in 2015. DEP will not, however, meet its 2015 swine waste and poultry waste set-aside requirements.

7. DEP has appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and billing period. For purposes of establishing the REPS Experience Modification Factor (EMF) rider in this proceeding, DEP's incremental costs for REPS compliance during the test period were $23,190,036, including costs incurred for its Wholesale Customers, and these costs were reasonably and prudently incurred. The Company's projected incremental costs for REPS compliance for the billing period are $32,250,073.

8. DEP's under-recovery of incremental costs amounts to $788,661 for the EMF period, April 2014 through March 2015.

9. The appropriate monthly amount of the REPS EMF rider per customer account, excluding the regulatory fee, to be collected during the billing period is $0.06 for residential accounts, ($0.18) for general service accounts, and $16.05 for industrial accounts.

10. The appropriate monthly amount of the REPS rider per customer account, excluding the regulatory fee, to be collected during the billing period is $1.11 for residential accounts, $6.83 for general service accounts, and $44.72 for industrial accounts.

11. The combined monthly REPS and REPS EMF rider charges per customer account, excluding the regulatory fee, to be collected during the billing period are $1.17 for residential accounts, $6.65 for general service accounts, and $60.77 for industrial accounts.

12. DEP's combined REPS and REPS EMF riders to be charged to each customer account for the billing period are within the annual cost caps established in G.S. 62-133.8(h)(4).

13. The research activities funded by DEP during the test period and planned for the billing period are recoverable pursuant to G.S. 62-133.8(h)(1)(b). The research costs are within the statute's $1 million annual limit. It is appropriate for DEP to provide, in its 2016 REPS rider application, the results of its REPS-related research when these results are publicly available, and the procedures for third parties to access the results when they are proprietary.

14. NCSEA's request for additional information in order to improve transparency of renewable energy certificates and Energy Efficiency Certificates (EEC's) is reasonable.

15. DEP has appropriately worked with the NC-RETs Administrator to satisfy and comply with the requirements set forth in the Poultry REC Shortfall Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-3

The evidence for these findings of fact can be found in DEP's Application, the requirements of G.S. 62-133.8, and Commission Rule R8-67.

G.S. 62-133.8(h)(4) requires the Commission to allow an electric utility to recover all of its incremental, reasonable, and prudent costs incurred to comply with G.S. 62-133.8 through an annual rider. G.S. 62-133.8(h)(1) provides that "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirements that are in excess of the electric power supplier's avoided costs, other than those costs recovered pursuant to G.S. 62-133.9. Commission Rule R8-67(e)(2) explains that the total costs reasonably and prudently incurred to purchase unbundled RECs constitute incremental costs and have no avoided cost component.

Commission Rule R8-67(e)(1) provides that the Commission shall schedule an annual public hearing to review an electric utility's REPS compliance costs. Subdivision (e)(3) of Rule R8-67 further provides that the test period for each utility shall be the same as the test period for purposes of Commission Rule R8-55. Rule R8-55 provides that DEP's test period is the twelve months ending March 31 of each year. Therefore, DEP proposed a test period for its REPS cost recovery proceeding of the twelve months ending March 31, 2015.

Rule R8-67(e)(4) provides that the REPS and REPS EMF riders shall be in effect for a fixed period which "shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55." In its current fuel charge adjustment proceeding, Docket No. E-2, Sub 1069, and in this proceeding, DEP proposed, without objection from any party, that its rate adjustments take effect on December 1, 2015, and remain in effect for a 12-month period. This period is referred to herein as the billing period.

The test and billing periods proposed by DEP were not challenged by any party. The Commission concludes that the test period appropriate for use in this proceeding is the twelve months ending March 31, 2015, and the appropriate billing period is the twelve months ending November 30, 2016.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

The evidence for these findings can be found in DEP's Application, the direct testimony, exhibits, and revised exhibit of DEP witness Jennings, the affidavit of Public Staff witness Batista and the requirements of G.S. 62-133.8. In addition, the Commission takes judicial notice of information contained in NC-RETS.

DEP witness Jennings described in her testimony the Company's efforts to comply with the REPS requirements, and she discussed these efforts more fully in the REPS compliance report, which was admitted into evidence as Jennings Exhibit No. 1. Witness Jennings testified that the Company has contracted to provide REPS services to the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek, the Town of Winterville, and the

City of Waynesville. No party took issue with DEP's purchase of RECs for the Wholesale Customers.

Witness Jennings testified that, for the calendar year 2014, the Company must generally supply an amount of at least 3 percent of its previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency measures (Total Obligation). She stated that as part of the Total Obligation the Company must supply energy in the amount of at least 0.07 percent of the previous year's North Carolina retail sales from solar resources (Solar Set-Aside). Witness Jennings testified that in 2015, the Total Obligation increases to 6 percent, and the Solar Set-Aside increases to 0.14 percent of the previous year’s NC retail sales.

G.S. 62-133.8(e) and (f) requires DEP and other electric suppliers in North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from swine and poultry waste resources (referred to as the Swine Waste Set-Aside and the Poultry Waste Set-Aside, respectively). However, in its 2014 Relief Order, the Commission delayed for one year the Swine Waste Set-Aside for 2014. Therefore, in 2015, the Company must supply energy in the amount of its pro-rata share of at least 0.07 percent of the previous year's total statewide aggregate retail sales to meet the Swine Waste Set-Aside, and energy in the amount of its pro-rata share of 700,000 megawatt-hours (MWh) to meet the Poultry Waste Set-Aside.

Witness Jennings further testified that the Company has submitted for retirement 1,109,096 RECs, which include 1,832 Senate Bill 886 RECs, each of which counts for two poultry waste and one general REC, to meet its Total Obligation of 1,112,760 RECs for calendar year 2014. Within this total, the Company has submitted for retirement 25,969 RECs to meet the Solar Set-Aside requirement, and 44,790 RECs along with 1,832 Senate Bill 886 RECs (which count as 3,664 poultry waste set-aside RECs) to meet the Poultry Waste Set-Aside requirement, for calendar year 2014. Specifically, the RECs to be used for 2014 compliance have been transferred from the NC-RETS Progress Energy Electric Power Supplier account to the Progress Energy Compliance Sub-Account and the Sub-Accounts of its Wholesale customers. She stated that during the two calendar years partially included in the prospective billing period, the Company’s estimated obligations are as follows[1]: in 2015, the Company estimates that it will be required to submit for retirement 2,262,185 RECs to meet its Total Obligation. Within this total, the Company is also required to retire the following: 52,784 solar RECs, 26,392 swine waste RECs, and 207,635 poultry waste RECs. In 2016, the Company estimates that it will be required to submit for retirement 2,232,332 RECs to meet its Total Obligation. Within this total, the Company estimates that will be required to retire approximately 52,088 solar RECs, 26,044 swine waste RECs, and 262,974 poultry waste RECs. Witness Jennings stated that the Company has complied with its Solar and Poultry Waste Set-Aside obligations for 2014 and that the Company is well-positioned to comply with its Solar Set-Aside and Total Obligation requirements in 2015; however, it projects that it will not meet its Poultry Waste Set-Aside requirement or its Swine Waste Set-Aside requirement in 2015. DEP witness Jennings noted that the Company's ability to meet its Swine and

[1] The Company’s projected obligations are based upon retail sales estimates included within Duke Energy Progress’s 2014 REPS Compliance Plan, filed in Docket No, E-100, Sub 141, and will be subject to change based upon actual prior year North Carolina retail sales data.

Poultry Waste Set-Asides is hampered by the lack of performance by signed counterparties on current contracts.

Public Staff witness Batista discussed in his affidavit that DEP has met the compliance requirements for 2014 by placing a sufficient number of general, solar and poultry RECs in the NC-RETS compliance sub-accounts of DEP and the Wholesale Customers. He also stated that the Public Staff has reviewed DEP's REPS Compliance Report for 2014 and recommends that the Commission approve compliance for DEP and the Wholesale Customers.

Based on the evidence presented and the record as a whole, the Commission finds and concludes that DEP and the Wholesale Customers for which it is providing REPS compliance services have fully complied with the REPS requirements for 2014, that DEP's 2014 REPS Compliance Report should be approved and that the RECs and EEC’s in the related NC-RETS compliance sub-accounts should be permanently retired.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-12

The evidence supporting these findings of fact appears in DEP’s application, the testimony, exhibits and revised exhibits of DEP witnesses Jennings and Williams, and the affidavits of Public Staff witnesses Batista and Boswell.

Witness Williams testified that DEP calculated its incremental costs associated with its purchases from renewable energy facilities, such that for each purchased power agreement with a renewable energy facility, DEP subtracted its avoided costs from the total costs associated with the renewable energy purchase to arrive at the incremental cost for that renewable energy purchase for the period in question. She explained that the cost of an unbundled REC is an incremental cost and has no avoided cost component. She testified that consistent with these procedures, the total cost incurred during the test period for REC purchases is included in incremental costs. Witness Williams further testified that total billing period projected costs for anticipated REC purchases are included in incremental costs.

DEP witness Jennings testified that besides the costs of purchases of renewable power and RECs, DEP seeks to recover costs associated with the support of various research and development efforts and studies, internal labor costs associated with REPS compliance activities, and non-labor costs associated with administration of REPS compliance. Among the non-labor costs associated with REPS are the Company’s subscription to the NC-RETS and an external REC accounting system.

For purposes of allocation, DEP witness Williams testified that incremental costs assigned to DEP NC retail customers are separated into two categories: costs related to solar, poultry and swine compliance requirements, and research and other incremental costs (Set-Aside and Other Incremental Costs); and costs related to the General Requirement (General Incremental Costs), which is calculated in Williams Exhibit No. 1.

She further stated that Set-Aside and Other Incremental Costs are allocated among customer classes based on per-account cost caps. General Incremental Costs are allocated among customer classes in a manner that gives credit for energy efficiency (EE) RECs (for which there are no General Incremental Costs) according to the relative energy reduction contributed by each customer class. As a result, witness Williams testified that General Incremental Costs are allocated among customer classes based on each class's pro-rata share of requirements for non-EE general RECs. She noted that this method of cost allocation is applicable to both the EMF and billing period costs. Witness Williams explained that, in the future, should this method result in an allocation of costs to a particular class in excess of the cap limit for that class, the excess over the respective cap for that class will be re-allocated proportionally to the remaining classes.

Witness Williams's revised exhibits show that DEP's incremental costs of retail REPS compliance were $23,050,896 for the EMF period. Her revised exhibits also show a $788,661 net under-recovery of incremental costs for the EMF period. The forecasted incremental costs for retail REPS compliance for the billing period, as shown through Williams's revised exhibits, amounted to a total of $32,121,073. The Public Staff agreed with DEP's proposed EMF and forecasted incremental costs.

Witness Williams, based on her revised exhibits, calculated the monthly REPS rider amounts of $1.11 for the residential class, $6.83 for the general class, and $44.72 for the industrial class. She also calculated the monthly REPS EMF rider amounts of $0.06 for the residential class, ($0.18) for the general class, and $16.05 for the industrial class. Thus, the combined proposed monthly REPS and REPS EMF rates are $1.17 for the residential class, $6.65 for the general class and $60.77 for the industrial class, not including the regulatory fee. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account to be collected during the billing period are $1.17 for residential accounts, $6.66 for general service accounts, and $60.85 for industrial accounts.

Public Staff witnesses Batista and Boswell stated in their affidavits that they had reviewed and analyzed the REPS incremental costs for which DEP has requested recovery in this proceeding, found them to be appropriate, and recommended their approval. No other party presented any evidence regarding DEP's REPS incremental costs. Witness Batista further stated that the Public Staff did not disagree with DEP's calculation of the EMF rate and that its proposed forecast rate was reasonable.

Witness Boswell stated in her affidavit that the Public Staff's investigation included procedures intended to evaluate whether the Company properly determined its per books incremental compliance costs and revenues, as well as the annual revenue cap for REPS requirements, during the test period. She stated that these procedures included a review of the Company's filing and other Company data provided to the Public Staff, as well as a review of certain specific types of expenditures impacting the Company's costs, including labor and research and development costs. Witness Boswell stated that performing the Public Staff's investigation required the review of numerous responses to written and verbal data requests, as well as discussions with the Company.

As a result of the Public Staff's investigation, witness Boswell recommended that DEP's proposed annual and monthly REPS EMF increment or decrement riders for each customer class be approved. These amounts produce annual increment or decrement REPS EMF riders of $0.70,

$(2.21), and $192.59, and monthly REPS EMF riders of $0.06, ($0.18), and $16.05, per customer account, excluding the regulatory fee, for residential, commercial, and industrial customers, respectively.

Therefore, based on the foregoing, the Commission finds and concludes that DEP's proposed REPS incremental costs for the test period are reasonable and prudent that its proposed REPS and EMF riders should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact appears in the testimony, exhibits, and revised exhibits of DEP witness Jennings and the affidavit of Public Staff witness Batista.

In compliance with the Commission's November 16, 2012 Order Approving REPS and REPS EMF Riders and 2011 REPS Compliance in Docket No. E-2, Sub 1020, DEP witness Jennings supplied testimony and exhibits on the results and status of various research studies for which DEP sought cost recovery in this proceeding. Witness Jennings provided the following information:

- DEP commissioned the Pacific Northwest National Laboratory, Power Costs Inc., and Clean Power Research to research and understand the operational impacts of solar at various penetration levels. Specifically, the study addressed the ancillary services impact of solar at the system level based on granular solar photovoltaic forecasts in the Company's service territory. The final report can be found at http://www.duke-energy.com/pdfs/carolinas-photovoltaic-integration-study.pdf.

- Rocky Mountain Institute (RMI) – The Company participates in eLab, a forum sponsored by RMI, composed of a number of North Carolina and nationally based entities, and organized to overcome barriers to economic deployment of distributed energy resources in the U.S. electric sector. Specifically, the Company seeks to gauge customer desires related to distributed resources and provide ideas of potential long-term solutions for distributed energy resources and microgrids. Company-specific reports and findings are not presently available; however, publicly available reports from e-Lab can be found at www.rmi.org/elab.

- The Company commissioned the University of North Carolina-Chapel Hill to analyze wind resources outside the barrier islands where potential may exist for large-scale offshore wind projects. There is not currently sufficient data to determine the feasibility of offshore wind projects in this area. UNC indicates that field data collection, modeling, and analysis work are ongoing.

- Electric Power Research Institute (EPRI) – In 2014, the Company subscribed to the following EPRI programs, the costs for which were recovered via the REPS rider: Program 84 – Renewable Energy Economics and Technology; and Program 187 – Solar. EPRI designates such study results as proprietary or as trade secrets and licenses such results to EPRI members, including the Company. As such, the

Company may not disclose the information publicly. Non-members may access these studies for a fee. Information regarding access to this information can be found at http://www.epri.com/Pages/Default.aspx.

- AWS Truepower – In 2014, the Company purchased wind generation profiles for the benefit of the IRP planning process. The Company used the wind profiles in understanding how wind generation would impact DEP's system if wind facilities are built in the Company's service territory.

- National Renewable Energy Lab (NREL) Alliance for Sustainable Energy – In 2014 the Company commissioned new studies from NREL that look at how smart inverters can be used in Distribution Management Systems and how these inverters impact the Company's current operations. This work will continue in 2015 with NREL, as needs will be comprehensively evaluated for proper modeling of smart inverters.

- Other Resources and Subscriptions – The Company subscribes to various renewable energy news and trade publications to gain access to market analysis, including price and supply/demand trends for renewable energy. Such publications are generally proprietary and provided to the Company under confidentiality licenses and, as such, the Company may not disclose the information publicly. Interested parties can obtain copies of such reports and analyses for a fee. The Company subscribes to, or has purchased services from, several publications, including Bloomberg New Energy Finance, IHS Global, Megawatt Daily, Greentech Media, and JD Energy.

According to witness Jennings' revised Exhibit No. 2, DEP spent $392,086 on REPS-related research during the test period; the Company plans to spend $400,000 during the billing period.

Therefore, based on the evidence presented, the Commission concludes that the costs of the research activities funded by DEP during the test period and planned for the billing period are appropriate research costs recoverable under G.S. 62-133.8(h)(1)(b), and that such research costs are within the $1 million annual limit provided in the statute. In addition, the Commission finds that the research information DEP provided is quite helpful. Therefore, the Commission finds that DEP shall continue to file this information with future REPS compliance reports. For those studies that are subject to confidentiality agreements, DEP will provide procedures for third parties to access the results. For research projects sponsored by EPRI, DEP will provide the overall program number and specific project number for each project, as well as an internet address or mailing address that will enable third parties to inquire about the terms and conditions for access to any portions of the study results that are proprietary.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact can be found in the Joint Motion for Witnesses to be Excused From Appearance at Evidentiary Hearing (Joint Motion to Excuse Witnesses) well as in the post hearing brief filed by NCSEA.

In its Joint Motion to Excuse Witnesses, DEP indicated that it had entered into a stipulation with NCSEA agreeing that DEP would file certain information regarding its EE certificates as an exhibit in future REPS proceedings. DEP noted that this information will be similar to what it provides already in Duke Energy Carolinas proceedings. Also, on October 15, 2015, NCSEA filed its post hearing brief with the Commission, in which NCSEA states that it does not challenge any of DEP's proposed REPs charges in this docket, however, NCSEA would request that the Commission include language in its final Order in this docket reflecting the stipulation between DEP and NCSEA that DEP will include a worksheet of its EEC inventory in future REPS rider applications. NCSEA notes that DEP and NCSEA have stipulated the following: "DEP agrees that it will file a worksheet in its future REPS recovery proceedings, detailing its energy efficiency certificate inventories, similar in format to what Duke Energy Carolinas, LLC filed on March 4, 2015, as Williams Exhibit No.6, in Docket No. E-7, Sub 1074. DEP will include in its proposed order in this matter this commitment to provide this worksheet as an exhibit in its future REPS recovery applications."

Based on the foregoing, the Commission concludes that this information would help provide additional transparency and, therefore, concludes that DEP should be required to file the information with the Commission in future REPS proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact can be found in the comments received in this docket from all parties regarding this matter, the Commission's various Order's on this matter, and the report submitted by the NC-RETS administrator in this docket.

On September 15, 2015, the NC-RETS administrator filed a letter with the Commission stating that corrections were made to 2013 retail sales amounts by a few electric power suppliers that were input to NC-RETS in August of 2015. These changes caused NC-RETS to re-calculate the 2014 poultry requirement for all electric power suppliers.[1] The letter goes on to state that the

[1] The Commission's rules require North Carolina electric power suppliers to report their previous year's retail sales into NC-RETS by June 1st of each year. The aggregate of all the reported retail sales is used by NC-RETS to calculate the poultry requirement for each North Carolina electric power supplier.

changes in 2013 retail sales resulted in lower 2014 poultry obligations for some electric power suppliers (those whose re-stated 2013 sales went down), and increased 2014 poultry obligations for those whose 2013 sales figures were unchanged or had gone up. For example, in NC-RETS the Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, compliance sub-accounts reflected non-compliance relative to their 2014 poultry obligations.

In order to resolve this issue as quickly and efficiently as possible, the Commission ordered that comments be filed on this matter by all parties affected. DEP and Duke Energy Carolinas, LLC filed comments jointly. ElectriCities of North Carolina, Inc., North Carolina Municipal Power Agency Number 1, and North Carolina Eastern Municipal Power Agency, filed joint comments, and the Public Staff, GreenCo, and Dominion North Carolina Power filed separate comments, as well.

On October 19, 2015, the Commission issued an Order requiring DEP to add 211 poultry RECs with vintages dated 2014 or earlier to its 2014 REPS compliance sub-account. Further, the Order required the NC-RETS administrator to submit a report to the Commission as to the status of this effort as soon as possible after the adjustments have been completed, but no later than November 6, 2015. The Order also asked all parties to provide comments as to alternative methods of allocating the aggregate poultry obligation in the future, if they wished.

On November 6, 2015, the NC-RETS Administrator filed a report with the Commission providing the status of the electric power suppliers' efforts to adjust the poultry RECs in their respective compliance sub-accounts in NC-RETS. The report provided a timeline of events and stated that DEP had been working with the NC-RETS Administrator as ordered and that as of November 4, 2015, Duke (being DEP and DEC in the report) had completed their resubmissions into the system and that their sub-accounts are now in compliance.

The Commission has reviewed the record, as well as the records in NC-RETS, and finds and concludes that DEP has satisfactorily complied with the Poultry Shortfall Order, and that DEP's poultry RECs have been adjusted to the proper amount in the appropriate NC-RETS compliance sub-accounts.

IT IS, THEREFORE, ORDERED, as follows:

1. That effective for service rendered on and after December 1, 2015, DEP shall be allowed to charge each residential customer a monthly EMF of $0.06 and a REPS rider in the amount of $1.11, for a total of $1.17; DEP shall be allowed to charge each general service customer a monthly EMF of ($0.18) and a REPS rider in the amount of $6.83, for a total of $6.65; and DEP shall be allowed to charge each industrial customer a monthly EMF of $16.05 and a REPS rider in the amount of $44.72, for a total of $60.77, excluding the regulatory fee. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account to be collected during the billing period are $1.17 for residential accounts, $6.66 for general service accounts, and $60.85 for industrial accounts.

2. That DEP shall file appropriate rate schedules and riders with the Commission to implement the provisions of this Order no later than 10 days from the date of this Order.

3. That DEP shall work with the Public Staff to prepare a joint proposed notice to customers of the rate changes ordered by the Commission in Docket Nos. E-2, Subs 1069, 1070, 1071, and 1088, and the Company shall file the proposed customer notice for Commission approval as soon as practicable.

4. That DEP's REPS compliance report for 2014 is hereby approved and the RECs in DEP's 2014 compliance sub-accounts in NC-RETS shall be retired.

5. That DEP shall file in all future REPS rider applications the results of studies the costs of which were recovered via its REPS rider, including the overall program number and specific project number for each project sponsored by EPRI; and for those studies that are subject to confidentiality agreements, information (including an internet or mailing address) regarding how parties can access those studies.

6. That DEP shall file in all future REPS rider applications a worksheet detailing its energy efficiency certificate inventories, similar in format to what Duke Energy Carolinas, LLC filed on March 4, 2015, as Williams Exhibit No. 6, in Docket No. E-7, Sub 1074.

7. That DEP has complied with the Poultry Shortfall Order and the poultry RECs included in its compliance sub-accounts for 2014 now reflect the appropriate number of poultry RECs.

ISSUED BY THE ORDER OF THE COMMISSION.
This the _17th_ day of November, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-2, SUB 1088

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Duke Energy Progress, LLC,	)	
Pursuant to G.S. 62-133.14 and Rule R8-70 to	)	ORDER APPROVING
Establish a Joint Agency Asset Rider for	)	JOINT AGENCY ASSET RIDER
Recovery of Costs Related to Facilities	)	
Purchased from Joint Power Agency	)	

HEARD: Tuesday, November 3, 2015, at 10:00 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Duke Energy Progress, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, NCRH 20/Post Office Box 1551, Raleigh, North Carolina 27601-1551

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For Carolina Industrial Group for Fair Utility Rates II:

Adam Olls, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Antoinette R. Wike, Chief Counsel, and Diana Downey, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On September 29, 2015, Duke Energy Progress, LLC (DEP or Company), filed an application to establish its initial Joint Agency Asset Rider (JAAR) pursuant to G.S. 62-133.14 and Commission Rule R8-70, which require the Commission to establish an annual rider to allow DEP to recover the North Carolina retail portion of all reasonable and prudent costs incurred to acquire, operate, and maintain the proportional interest resulting from the acquisition of the North Carolina Eastern Municipal Power Agency (NCEMPA) ownership interests in certain generating facilities. DEP's application was accompanied by the testimony and exhibits of Jane L. McManeus. In its application and pre-filed testimony, DEP sought approval of the proposed rider, which incorporated the Company's proposed adjustments in its North Carolina retail rates.

On October 5, 2015, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice, in which the Commission set this matter for hearing, established discovery guidelines, and provided for public notice of the hearing. On October 6, 2015, Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed its petition to intervene, which the Commission granted on October 7, 2015. On October 8, 2015, Carolina Utility Customers Association, Inc. (CUCA), filed its petition to intervene, which was granted on October 12, 2015. The intervention and participation by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On October 22, 2015, the Public Staff filed the affidavit of James G. Hoard, Director, Public Staff Accounting Division. No other party pre-filed testimony in this docket.

On October 28, 2015, DEP filed a letter with the Commission including revised exhibits and amending its application and previously filed exhibits, including the exhibits attached to the testimony of Jane L. McManeus. DEP's filing noted that the demand rate for Medium General Service (MGS) class customers being billed on a demand basis was calculated incorrectly, which will require a new public notice and hearing related to that rate. DEP proposed to proceed with the originally filed MGS demand rate and stated its intent to make a subsequent filing with the Commission to correct the rate, effective as of February 1, 2016.

This matter came on for hearing as scheduled on November 3, 2015. No public witnesses appeared. DEP's application and the testimony and exhibits, as revised, of Company witness McManeus were admitted into evidence. The Public Staff presented the affidavit and additional testimony of witness Hoard. No other party presented witnesses.

Based upon the foregoing, DEP's verified application, the testimony and exhibits received into evidence at the hearing, and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. DEP is a duly organized corporation existing under the laws of the State of North Carolina, engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina and South Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEP is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.14 and Commission Rule R8-70.

2. On July 31, 2015, DEP acquired NCEMPA's undivided ownership interests of 18.33% in the Brunswick Steam Electric Plant (Brunswick Units 1 and 2), 12.94% in the Roxboro Steam Electric Plant (Roxboro Unit 4), 16.17% in the Mayo Electric Generating Plant (Mayo Unit 1), and 16.17% in the Shearon Harris Nuclear Power Plant (Harris Unit 1) (collectively, Joint Units). On May 12, 2015, the Commission issued an Order Approving Transfer of Certificate and Ownership Interests in Generating Facilities in Docket Nos. E-2, Sub 1067 and E-48, Sub 8, which approved the transfer of NCEMPA's ownership interests in the Joint Units to DEP.

3. G.S. 62-133.14 allows DEP to recover the North Carolina retail portion of all reasonable and prudent costs incurred to acquire, operate, and maintain the proportional interest in the generating facilities purchased from NCEMPA. Commission Rule R8-70(d) provides that for the initial filing to establish the JAAR, an electric public utility shall submit an application no later than 60 days from the date of acquisition containing such information as the Commission may require to recover all estimated financing and non-fuel operating costs which the utility expects to incur during the period from the date of acquisition until the effective date of rates approved by the Commission in DEP's next annual JAAR proceeding.

4. The initial rider provides for recovery of the costs expected to be incurred from December 1, 2015, through November 30, 2016, with a three-year amortization of the costs expected to be incurred from August 1, 2015, through November 30, 2016.

5. DEP requested a total increase of $65.797 million in its North Carolina retail revenue requirement, including regulatory fee, for the period December 1, 2015, through November 30, 2016, associated with the acquisition of NCEMPA's undivided ownership interest in the Joint Units.

6. The annual levelized costs associated with the acquisition of the Joint Units at the time of purchase were $65.964 million. DEP also requested an additional $7.219 million in annual pre-tax costs associated with the acquisition costs not included in the levelization of costs. These costs are reasonable and prudent under G.S. 62-133.14(b)(1).

7. DEP requested $7.236 million for the annual amortization of costs incurred since the purchase of the Joint Units, but prior to the rates being effective which the Company is deferring. The annual amortization is based on a three-year amortization period. These costs are reasonable and prudent under G.S. 62-133.14(b)(1).

8. DEP's requested additional $3.981 million in annual financing and operating costs related to estimated capital additions during the rate period are reasonable and prudent under G.S. 62-133.14(c).

9. DEP's estimate of the annual non-fuel operating costs from December 1, 2015, to November 30, 2016, of $67.485 million are reasonable and prudent.

10. DEP has adjusted the total annual revenue requirement by $86.185 million to reflect the reduction in North Carolina retail jurisdiction's portion of financing and operating costs related to DEP's other used and useful generating facilities owned at the time of the acquisition. This reduction in costs assigned to North Carolina retail customers results from greater costs being assigned to wholesale customers because the Company is now supplying the entire electric requirements of NCEMPA.

11. Under G.S. 62-133.14(b)(5), these costs shall be allocated under the customer allocation methodology approved by the Commission in Docket No. E-2, Sub 1023, DEP's last general rate case, to produce the following rates by customer class, which rates the Commission finds to be just and reasonable, subject to consideration of the Company's proposed adjustment to the MGS demand rate filed on November 5, 2015, and proposed to be effective February 1, 2016

Rate Class	Applicable Schedule(s)	Incremental Rate*
Non-Demand Rate Class (dollars per kilowatt-hour)		
Residential	RES, R-TOUD, R-TOUE, R-TOU	0.00183
Small General Service	SGS, SGS-TOUE	0.00223
Medium General Service	CH-TOUE, CSE, CSG	0.00192
Seasonal and Intermittent Service	SI	0.00339
Traffic Signal Service	TSS, TFS	0.00097
Outdoor Lighting Service	ALS, SLS, SLR, SFLS	0.00000
Demand Rate Classes (dollars per kilowatt)		
Medium General Service	MGS, GS-TES, AP-TES, SGS-TOU	0.42
Large General Service	LGS, LGS-TOU	0.65

* Incremental Rates, shown above, include North Carolina regulatory fee of 0.148%.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 1

This Finding of Fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NOS. 2- 4

The evidence for these Findings of Fact is found in DEP's application and the testimony of DEP witness McManeus.

Pursuant to G.S. 62-133.14, upon the filing of a petition of an electric utility and a public hearing, the Commission shall approve an annual rider to the utility's rates for the North Carolina retail portion of reasonable and prudent costs incurred to acquire, operate and maintain the Joint Units. The acquisition costs shall be deemed reasonable and prudent and shall be levelized over the useful life of the Joint Units at the time of acquisition. Financing costs shall be included and shall be equal to the weighted average cost of capital as authorized in the utility's most recent general rate case.

The utility may recover an estimate of operating costs based on the experience of the test period and the costs projected for operation of the Joint Units for the next twelve months subject to the filing of an annual adjustment including any under- or over-recovery, any changes necessary to recover costs for the next twelve-month period, or any changes to the cost of capital or customer allocation methodology occurring in a general rate case after the establishment of the initial rider.

Commission Rule R8-70(d) provides that, for the initial filing to establish the JAAR, an electric public utility shall submit an application no later than 60 days from the date of acquisition containing such information as the Commission may require to recover all estimated financing and non-fuel operating costs that the utility expects to incur during the period from the date of acquisition until the effective date of rates approved by the Commission in the Company's next annual JAAR proceeding. DEP acquired the Joint Units on July 31, 2015. Therefore, the costs to be considered for this initial filing are the financing and non-fuel operating expenses incurred from August 1, 2015, to November 30, 2016, which will be effective for the rate period December 1, 2015, through November 30, 2016.

The Commission concludes that DEP's application is complete and filed in compliance with G.S. 62-133.14 and Commission Rule R8-70.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence for these Findings of Fact is found in the testimony of DEP witness McManeus and in the affidavit of Public Staff witness Hoard.

Witness McManeus testified that DEP's annual levelized cost associated with the acquisition price of the Joint Units was $65.964 million, and the Company had followed the definition of these costs as set forth in G.S. 62-133.14 and Commission Rule R8-70, under which acquisition costs means the amount paid by DEP to acquire the proportional interest in generating facilities and related assets purchased from NCEMPA, including the amount paid above the net book value of the facilities. In general terms, levelized revenue requirement represents recovery of the acquisition cost for the NCEMPA assets spread evenly over the life of the assets. Witness McManeus also included additional financing and operating costs of $7.219 million associated with assets purchased that were not included as part of the levelized costs. In her testimony, witness McManeus described these costs as including inventory amounts that are part of the asset acquisition costs, nuclear fuel inventory, and materials and supplies inventory. Because these assets are not depreciated, the financing costs for these amounts are calculated on the basis of the average investment for the rate period.

Additionally, the Company incurred financing and operating costs related to the purchase of the Joint Units following the acquisition, but prior to the effective date of the JAAR that the Company deferred. The annual amortization over a three-year period of these deferred costs is $7.236 million. Witness McManeus noted that the Company has agreed to amortize these costs over three years for the benefit of customers.

North Carolina General Statutes Section 62-133.14(b)(2) states that the JAAR shall include financing costs equal to the weighted average cost of capital as authorized by the Commission in the electric public utility's most recent general rate case. Witness McManeus testified the Company's calculation of financing costs included the debt and equity return on the average rate base investment for the period associated with the purchase. Additionally, the Company computed the debt and equity rate of return and the Company's weighted average net-of-tax cost of capital as authorized by the Commission in DEP's most recent general rate case.

In the affidavit filed with the Commission, Public Staff witness Hoard stated that the Public Staff's investigation included an evaluation of the data used in the rider computation, the mathematical accuracy of the computations and the consistency of the computations with the requirements of G.S. 62-133.14 and Commission Rule R8-70. Witness Hoard indicated that the Public Staff determined that the data used by the Company to determine the initial JAAR is reasonable and that the computations are mathematically accurate and consistent with the requirements of the statute and the Commission Rule.

The Commission concludes that under G.S. 62-133.14(b)(1) DEP should be allowed to recover in the annual JAAR the financing and depreciation costs associated with the acquisition costs of the Joint Units on a levelized basis in the amount of $65.964 million annually, the annual amount of $7.219 million of financing and operating costs associated with acquisition costs that are not levelized, and $7.236 million annually reflecting a three-year amortization of deferred costs including a return on the outstanding deferred costs over this amortization period, and that such costs are reasonable and prudent.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NOS. 8 AND 9

The evidence for these Findings of Fact is found in DEP's application, the testimony of DEP witness McManeus and the affidavit of Public Staff witness Hoard.

The Company requested annual costs of $3.981 million to be included in the JAAR for financing and operating costs related to estimated capital additions to be incurred during the period August 2015 through November 2016 and an estimated $67.485 million for annual non-fuel operating costs over the period December 1, 2015, to November 30, 2016. Under G.S. 62-133.14(b)(3) the Commission shall include in the rider an estimate of operating costs based on the prior year's experience and the costs projected for the next twelve months and shall include the annual financing and operating costs for any proportional capital investments in the acquired electric generation facilities. The Commission concludes that these costs are reasonable and prudent under G.S. 62-133.14(b)(3). The Commission notes that DEP will file a joint agency asset rolling recovery factor (Joint Agency Asset RRF) adjustment rider to include a true-up between estimated and actual costs incurred under G.S. 62-133.14(c) in its next JAAR proceeding. The deferred costs related to any true-up is to be recorded as a regulatory asset or regulatory liability including a return on the deferred balance each month. Commission Rule R8-70(c) requires the Company to propose annual updates to its JAAR in order for the hearing to be held as soon as practicable after the fuel adjustment rider hearing held by the Commission pursuant to Rule R8-55.

Under Commission Rule R8-70(d)(2) the initial filing should include a special fuel rider to be eliminated at the effective date of the implementation of a fuel cost rate per Rule R8-55, which reflects system fuel costs that include the acquired plant assets. The Commission notes that DEP chose not to file a special fuel rider in this proceeding. Due to the timing of the implementation of the initial rider, the Company determined that a filing to establish a special fuel rider in this proceeding was not necessary. In its most recent fuel filing in Docket No. E-2, Sub 1069, DEP reflected the fuel savings attributable to the joint agency asset purchase. Because the previously filed fuel rates, if approved by the Commission, will become effective concurrently with this initial rider on December 1, 2015, a special fuel rider is not required.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 10

The evidence for this Finding of Fact is found in DEP's application and the testimony of DEP witness McManeus.

Under G.S. 62-133.14(b)(4) the JAAR shall include adjustments to reflect the North Carolina retail portion of financing and operating costs related to the electric public utility's other used and useful generating facilities owned at the time of the acquisitions to properly account for updated jurisdictional allocation factors. This adjustment benefits DEP customers by reducing DEP's annual retail revenue requirement by $86.185 million. Witness McManeus testified that the revenue reductions reflect changes in jurisdictional allocation factors resulting from the additional NCEMPA load that will be served by the Company's portfolio of generating facilities owned at the time of the acquisition. As a consequence, a greater portion of the cost of the Company's other generating facilities will be allocated to its wholesale jurisdiction, while a lesser portion will be allocated to its retail jurisdictions. The Commission concludes that a reduction in the costs to be recovered through the JAAR of $86.185 million to reflect the annual reduction in DEP's retail revenue requirement because of greater costs being assigned to wholesale customers is appropriate.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 11

The evidence for this Finding of Fact is found in DEP's application, the testimony and exhibits of DEP witness McManeus, and the affidavit and testimony of Public Staff witness Hoard.

North Carolina General Statutes Section 62-133.14(b)(5) provides that the costs of the rider shall be allocated under the cost allocation methodology used in DEP's last general rate case, Docket No. E-2, Sub 1023. DEP witness McManeus testified that after the Company reduced its retail allocation factor to reflect the increase in wholesale power sales to NCEMPA, it allocated the resulting revenue requirement based on the methodology consistent with its last general rate case to produce the rates reflected for each rate class as shown below.

In his affidavit, witness Hoard stated that the Public Staff investigated and reviewed DEP's application and determined the data used by the Company to develop the initial JAAR is reasonable and that the computation of the JAAR is mathematically reasonable, accurate, and in compliance with the requirements of G.S. 62-133.14 and Commission Rule R8-70. Witness Hoard recommended the rider amounts as proposed by the Company be approved.

DEP acknowledged an error in its calculation of the demand rate for Medium General Service of $0.42/kW. DEP asked the Commission to approve the listed rates effective December 1, 2015, and on November 5, 2015 filed the supplemental testimony and exhibits of witness McManeus to correct the MGS demand rate and requested that this change become effective February 1, 2016.

The Commission, therefore, finds the cost allocation methodology used by DEP to be consistent with the methodology approved by the Commission in DEP's last general rate case and the rates produced to be just and reasonable, subject to consideration of the Company's proposed adjustment to the MGS demand rate filed on November 5, 2015, and proposed to be effective February 1, 2016. The Commission will consider this requested change to the MGS demand rate and issue a subsequent order on this issue.

Rate Class	Applicable Schedule(s)	Incremental Rate*
Non-Demand Rate Class (dollars per kilowatt-hour)		
Residential	RES, R-TOUD, R-TOUE, R-TOU	0.00183
Small General Service	SGS, SGS-TOUE	0.00223
Medium General Service	CH-TOUE, CSE, CSG	0.00192
Seasonal and Intermittent Service	SI	0.00339
Traffic Signal Service	TSS, TFS	0.00097
Outdoor Lighting Service	ALS, SLS, SLR, SFLS	0.00000
Demand Rate Classes (dollars per kilowatt)		
Medium General Service	MGS, GS-TES, AP-TES, SGS-TOU	0.42
Large General Service	LGS, LGS-TOU	0.65

* Incremental Rates, shown above, include North Carolina regulatory fee of 0.148%.

Witness Hoard was questioned by the Commission about his statement that the Company's calculations reflected the current North Carolina State income tax rate of 5% and did not factor in the new rate of 4%, which is scheduled to become effective January 1, 2016. In response to the Commission's questions, witness Hoard indicated that the effect of the tax change was very small and that a separate adjustment was not warranted because it would produce an insignificant rate impact. However, because this initial rider is a prospective rider using numerous projections and inputs that will be adjusted to reflect actual costs and recoveries in subsequent proceedings, an adjustment to the tax rate calculation will be made in the next annual proceeding, which will also require a true-up of additional estimated inputs included in the current rider. The Commission concludes that the rate impact of the tax rate change is de minimis, and it is reasonable to include it as part of the adjustments to be made in future proceedings.

Lastly, witness Hoard stated that the Company and the Public Staff will continue to develop the details and procedures for the monthly reporting requirements under Rule R8-70 and submit them to the Commission for approval. The Commission, therefore, shall require that DEP and the Public Staff, as they agreed, continue to develop such details and procedures for submission to the Commission for approval.

IT IS, THEREFORE, ORDERED, as follows:

1. That DEP shall be allowed to charge in a rider $65.797 million on an annual basis to recover the costs in relation to the acquisition of the Joint Units;

2. That the costs shall be allocated using the customer allocation methodology used in DEP's last general rate case, as shown in DEP's application and the affidavit of James G. Hoard of the Public Staff;

3. That the rates reflected in the Schedule listed in Finding of Fact No. 11 of this Order are hereby approved, effective December 1, 2015;

4. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket No. E-2, Subs 1023, 1069, 1070, 1071, and 1088, and the Company shall file the proposed customer notice for Commission approval as soon as practicable; and

5. That DEP and the Public Staff shall continue to develop details and procedures for the monthly reporting requirements for submission to the Commission for approval.

ISSUED BY THE ORDER OF THE COMMISSION.
This the 19th day of November, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. A-41, SUB 14

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Bald Head Island Transportation, Inc., to Reduce Fuel Surcharge Pursuant to Commission Rule R4-13	)))	ORDER REDUCING FUEL SURCHARGE EFFECTIVE APRIL 1, 2015

BY THE COMMISSION: On February 23, 2015, Bald Head Island Transportation, Inc. (BHIT), filed an application under the procedures set forth in Commission Rule R4-13, seeking authority to reduce its fuel surcharge by $0.50 per round-trip ticket and $63.00 per Class VIII annual pass purchased on or after April 1, 2015, so that the ticket prices for its round-trip ferry tickets and Class VIII annual passes will equal its base rates, and the fuel surcharge will be zero.

The actual average price paid by BHIT for fuel in 2014, is $3.450 per gallon, in comparison to the $2.53[1] fuel cost per gallon included in base rates in BHIT's last general rate case, Docket No. A-41, Sub 7. As of December 31, 2014, BHIT's fuel tracking account balance reflects a $385,929 overcollection. Although the actual fuel costs are still greater than the fuel cost per gallon included in the base rates approved in the last rate case, BHIT proposes reducing its fuel surcharge so that the overcollection in its fuel tracking account will become less over time. By entirely eliminating the fuel surcharge at this time, BHIT seeks to reduce the fuel tracking account balance over two years, as shown in Exhibit A to the application.

The matter was presented to the Commission at its Regular Staff Conference on March 23, 2015. The Public Staff stated it had reviewed the application and recommended approval as filed.

Based upon a review of the application and the recommendation of the Public Staff, the Commission is of the opinion that the proposed reduction in the fuel surcharge should be allowed to become effective as filed.

IT IS, THEREFORE, ORDERED as follows:

1. That BHIT is authorized to reduce its fuel surcharge by $0.50 per round trip ticket and $63.00 per Class VIII annual pass purchased on or after April 1, 2015, resulting in a fuel surcharge of zero.

[1] In its application, BHIT stated that the fuel component of rates per gallon in base rates is $2.185. The $2.185 is the fuel component of rates, not the fuel cost per gallon included in base rates. As shown on Line 1, Column (c) of Hoard Exhibit 1, Schedule 4-2 Revised filed on October 21, 2010 in Docket No. A-41, Sub 7, the fuel price per gallon in the last rate case was $2.53.

2. That the fuel component of each round trip ticket that should be used for purposes of determining the under or overcollection of fuel costs reflected in the fuel tracker account, effective April 1, 2015, is $2.185.

3. That prior to implementing the approved fuel surcharge, BHIT shall file with the Public Staff Transportation Rates Division and the Chief Clerk a supplement to its existing tariff consistent with Ordering Paragraph No. 1.

4. That BHIT shall prominently post the new rates in all locations where its rates are currently posted for the benefit of the public.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of March, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Chairman Edward S. Finley, Jr., and Commissioner Susan W. Rabon did not participate in this decision.

DOCKET NO. G-9, SUB 644

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Piedmont Natural Gas	)	
Company, Inc., for Order Requiring	)	
Frontier Natural Gas Company, LLC,	)	ORDER APPROVING SPECIAL
to Provide Service and Application of	)	TRANSPORTATION CONTRACT
Frontier Natural Gas Company, LLC,	)	
to Serve a Certain Customer in	)	
Davie County	)	

BY THE COMMISSION: On January 22, 2014, Piedmont Natural Gas Company, Inc. (Piedmont), filed a Petition in Docket No. G-9, Sub 644, requesting that the Commission order Frontier Natural Gas Company, LLC (Frontier), to negotiate a transportation/exchange agreement with Piedmont to sell or exchange natural gas for Piedmont to use in serving PalletOne of North Carolina, Inc. (PalletOne), a manufacturing facility located in Piedmont's franchise territory in Davie County, North Carolina.

On January 23, 2014, Frontier filed a Petition in Docket No. G-40, Sub 121, requesting that the Commission authorize Frontier to serve PalletOne and that the Commission adjust Frontier's and Piedmont's franchised territories to reflect such authorization.

On January 27, 2014, the Commission issued an order consolidating the two dockets into Docket No. G-9, Sub 644, and requiring Piedmont and Frontier to file responses to one another's petitions. Further, the Order required that the Public Staff review the responses of Piedmont and Frontier and file a statement of its position and its recommendation for the most appropriate arrangements for providing gas service to PalletOne.

On February 21, 2014, Piedmont and Frontier filed a Joint Motion for Extensions of Time and Notice of Consent to Arbitration, which submitted the matter to the Commission as an arbitrator pursuant to G.S. 62-40. In addition, Piedmont and Frontier requested extensions of time to reply to one another's petitions and for the Public Staff to file its statement of position and recommendation. The Commission granted the extensions of time by Order issued on February 21, 2014.

On March 3, 2014, Piedmont and Frontier filed their respective responses to one another's petitions. Also on that date, Piedmont filed the Affidavit of William C. Williams in support of its response.

On March 14, 2014, Piedmont and Frontier filed a Notice of Agreement on Settlement Terms and Joint Motion to Hold Docket in Abeyance. In their motion, Piedmont and Frontier stated that they had reached an agreement on the key terms of a settlement of this dispute. Further, they requested that the Commission hold this docket in abeyance until they file and the Commission approves a special transportation contract between them that will provide a plan for service to PalletOne and resolve this matter.

On March 19, 2014, the Commission issued an Order Holding Docket in Abeyance and Requiring Status Reports.

On December 11, 2014, Piedmont and Frontier filed a Joint Motion for Approval of a Special Transportation Contract, stating that they have finalized a contract between Piedmont and Frontier for service to PalletOne and requesting Commission approval of the contract. The Special Transportation Contract (STC) was attached to the motion as confidential Exhibit A.

On January 5, 2015, the Commission issued an Order Requesting Recommendation of the Public Staff, ordering the Public Staff to file its comments and recommendations regarding Commission approval of the proposed STC. Further, the Commission's Order provided Frontier and Piedmont the opportunity to respond to the Public Staff's comments and recommendation.

On February 4, 2015, the Public Staff filed a motion requesting an extension of time to file its comments and recommendations, which was granted by the Commission on the same date.

On February 6, 2015, the Public Staff filed its comments and recommendations. The Public Staff stated that it had reviewed the STC and other information provided by Piedmont and Frontier in response to the Public Staff's data requests. The Public Staff further stated that the STC involves a transportation/exchange arrangement whereby Frontier's facilities are used to transport natural gas to Piedmont's facilities through a Frontier meter facility and Piedmont returns equal volumes to Frontier's city gate located in Salisbury, North Carolina. The transportation/exchange arrangement enables Piedmont to serve PalletOne, a new customer located in Piedmont's service territory. Piedmont will reimburse Frontier for the cost of the facilities, including the income tax gross-up for contributions in aid of construction required by the Commission's Order on Motion for Clarification issued September 3, 2013, in Docket No. M-100, Sub 113A, and pay a volumetric energy charge and monthly facilities charge. Based on its investigation, the Public Staff determined that the terms of the STC are within the parameters set forth in G.S. 62-142.

The Public Staff recommended that Piedmont be allowed to include the per therm volumetric/energy charge paid by Piedmont to Frontier as gas costs. The amount paid by Piedmont to Frontier for the facilities will be included as plant in service, and the monthly facilities charge paid by Piedmont will be recorded as operation and maintenance expense.

The Public Staff further recommended that the Commission issue an order concluding that the STC is not unlawful and does not violate the rules and regulations of the Commission, and allowing Frontier to provide service to Piedmont pursuant to the STC. The Public Staff also recommended that the order state that the Commission's acceptance of the STC neither constitutes approval of the amount of any compensation paid thereunder nor prejudices the right of any party to take issue with any provision of the STC in a future proceeding.

The Public Staff stated that Piedmont and Frontier are in agreement with the Public Staff's recommendations. In addition, the Public Staff noted that similar transportation/exchange arrangements between local distribution gas companies have been approved by the Commission in Docket Nos. G-9, Sub 457 and G-21, Sub 414.

On February 19, 2015, Piedmont and Frontier filed a Joint Proposed Order Approving Contract.

Based on the record and its review of the Special Transportation Contract, as required by G.S. 62-142 and Commission Rule R6-62, the Commission concludes that the Special Transportation Contract is not unlawful, does not violate the rules and regulations of the Commission, and is in the public interest. Accordingly, the Commission finds good cause to allow the Special Transportation Contract to become effective as filed.

IT IS, THEREFORE, ORDERED as follows:

1. That Frontier is hereby authorized to provide natural gas service to Piedmont pursuant to the Special Transportation Contract;

2. That Piedmont is allowed to include the per therm volumetric/energy charge paid by Piedmont to Frontier as gas costs, that the amount paid by Piedmont to Frontier for the facilities will be included as plant in service, and that the monthly facilities charge paid by Piedmont will be recorded as operation and maintenance expense; and

3. That the Commission's acceptance of the Special Transportation Contract filed in this docket shall not constitute approval of the amount of any compensation paid thereunder, or prejudice the right of any party to take issue with any provision of the Special Transportation Contract in a future proceeding.

ISSUED BY ORDER OF THE COMMISSION
This the _2nd_ day of March, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. G-9, SUB 631
DOCKET NO. G-9, SUB 642

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas	)	
Company, Inc., for Approval of Annual	)	ORDER APPROVING STIPULATION
Adjustment of Rates Under Appendix E	)	
of its Service Regulations	)	

BY THE COMMISSION: On December 17, 2013, the Commission issued an Order Approving Partial Rate Increase and Allowing Integrity Management Rider (Rate Order) in Docket No. G-9, Sub 631. The Rate Order, among other things, approved the implementation of an Integrity Management Rider (IMR) by Piedmont Natural Gas Company, Inc. (Piedmont), pursuant to G.S. 62-133.7A. Further, the Rate Order included the approval of an IMR mechanism (Mechanism) for calculating and collecting the IMR. In summary, the Mechanism provides for rate adjustments on February 1st of each year based upon qualifying capital investments in integrity management and pipeline safety projects as of October 31 of the preceding year as reported by Piedmont to the Commission in an annual report (Annual IMR Report). Pursuant to the Rate Order, the IMR mechanism is incorporated into Piedmont's approved tariff as Appendix E to its Service Regulations.

On February 5, 2014, in Docket No. G-9, Sub 641, the Commission issued an Order Approving Rate Adjustments Effective February 1, 2014, and on January 26, 2015, in Docket No. G-9, Subs 642 and 659, the Commission issued an Order Approving Rate Adjustments Effective February 1, 2015 (2015 IMR Order). These Orders approved implementation of annual IMRs for the recovery of Piedmont's integrity management and pipeline safety costs. In the 2015 IMR Order, the Commission noted that the Public Staff's recommended approval of the IMR rate adjustments was subject to further review and determination of the reasonableness and prudence of the capital investments and associated costs reflected in the IMR, such review to be conducted as a part of Piedmont's annual IMR adjustment proceedings or next general rate case.

On September 4, 2015, Piedmont and the Public Staff filed a Stipulation and Settlement Agreement (Stipulation) in Docket No. G-9, Subs 631 and 642. In summary, the Stipulation recounts the history of Piedmont's IMR, describes the issues between Piedmont and the Public Staff and the proposed resolution of the issues, and proposes changes to the process for reviewing and adjusting Piedmont's IMR.

On September 28, 2015, the Commission issued an Order Requesting Comments. The Order included the following five questions that the Commission requested the parties to address as part of their initial and reply comments.

1. The Stipulation proposes 6-month IMR reviews to be concluded annually on June 1 and December 1 with Commission approved IMR rate adjustments. In order to lessen the number of annual Piedmont rate changes, would it be appropriate for the Commission to schedule one of the 6-month IMR reviews to coincide with the Commission's annual review of Piedmont's gas costs pursuant to G.S. 62-133.4?

2. The Stipulation states, on page 4, that "the Public Staff has not yet completed its audit of Piedmont's Integrity Management Plant Investment for the thirteen month period October 2013 through October 2014." Does the Public Staff intend to complete its audit of these costs? If so, how will any adjustments to such costs be brought to the Commission's attention and reflected in Piedmont's future IMRs?

3. Pursuant to the Rate Order, the IMR is presently reviewable four years from January 1, 2014, its effective date, or in Piedmont's next general rate case, whichever is earlier. However, the Stipulation states, on page 7, that the IMR mechanism shall be reviewed by the Commission four years from November 1, 2015, or in Piedmont's next general rate case, whichever is earlier. Please explain why Piedmont and the Public Staff believe it would be in the public interest to extend the specific IMR review date.

4. Pursuant to the Rate Order, any party has the right to petition the Commission to terminate or modify Piedmont's IMR at any time on the grounds that it is no longer in the public interest. Would approval of the Stipulation by the Commission eliminate this right of any party?

5. In the Rate Order, the Commission concluded that the version of the IMR mechanism approved by the Commission was more favorable to ratepayers "because it provides for a single annual adjustment to rates rather than the bi-annual adjustment proposed in the Company's originally proposed version of the mechanism." Please explain why Piedmont and the Public Staff believe that the Commission should now change this conclusion.

On October 23, 2015, Carolina Utility Customers Association, Inc. (CUCA) filed initial comments, and Piedmont and the Public Staff filed joint initial comments. On November 6, 2015, Piedmont and the Public Staff filed joint reply comments.

INITIAL COMMENTS

CUCA's Comments

With respect to Question 1 regarding whether IMR reviews should coincide with annual cost reviews, CUCA states that manufacturers operate on annual energy budgets, so minimal rate changes are preferable for budgetary planning purposes. CUCA suggests that one of the proposed 6-month IMR reviews should, therefore, coincide with Piedmont's annual gas cost review.

In response to Question 2 regarding the Public Staff's audit, CUCA advocates a timely review of costs to ensure confidence in regulatory oversight and to correct any problems or miscalculations relating to Piedmont's cost recovery. CUCA suggests that an outside consultant be retained to assist the Public Staff in its work, if needed, to complete the audit.

In response to Question 3 regarding the extension of the IMR review by one year, CUCA states that it was not consulted about any of the changes proposed by the Public Staff and Piedmont. CUCA opposes extending the review date for the IMR mechanism beyond the originally stipulated term.

In response to Question 4 regarding petition rights, CUCA states that the Stipulation does not eliminate the right of any party to petition the Commission to terminate or modify Piedmont's IMR. However, CUCA points out that its rights as a party to the original Stipulation to participate in the more recent discussions between Piedmont and the Public Staff were overlooked by both parties and asserts that it cannot effectively protect its rights when it is excluded from discussions.

In response to the Question 5 regarding bi-annual adjustments, CUCA reiterates that multiple rate changes upset the budgetary planning process of manufacturers. For that reason, CUCA argues that the change sought by the Public Staff and Piedmont is not favorable to ratepayers and should be rejected.

<u>Joint Comments of Piedmont and the Public Staff</u>

In responding to Question 1, the Public Staff and Piedmont assert that the proposed fall IMR review should not be combined with Piedmont's annual gas cost prudence review proceeding. They note that the gas cost review proceeding is meant to and does focus on Piedmont's gas costs, which are a flow-through item of expense embedded in Piedmont's rates, whereas the IMR surcharge mechanism is purely an incremental margin recovery mechanism. Further, the dates set forth in the Stipulation were adopted based on detailed analysis and discussions and cannot be easily changed without impacting other dates agreed to in the Stipulation. The stipulated schedule provides for a presentation to the Commission on or about March 1 of each year. Therefore, it is the intent of the stipulating parties that the bi-annual rate adjustments under the IMR be allowed to go into effect subject to a limited review for compliance with the Company's tariff and basic accounting accuracy.

Additionally, the Public Staff intends to continue to monitor and review the Company's IMR surcharges and accounts on a monthly basis through ongoing review of monthly reports submitted for that purpose. The Public Staff will present to the Commission information necessary for the Commission to authorize bi-annual rate adjustments under the IMR mechanism subject to further review in the annual review process in the spring of each year. Therefore, because the annual gas cost prudence reviews do not invariably result in rate changes and are sometimes extended for a variety of reasons, Piedmont and the Public Staff state that it would not be helpful to tie routine IMR surcharge changes in the fall of each year to rate changes that may result from potentially more involved annual prudence review proceedings.

In reference to Question 2, Piedmont and the Public Staff clarify that no further audit procedures for the thirteen-month period October 2013 through October 2014 are anticipated or will be pursued by the parties under the Stipulation.

In response to the Question 3, Piedmont and the Public Staff assert that a review of the Mechanism has essentially occurred with the process of coming to an agreement on an administrative solution to issues between Piedmont and the Public Staff regarding implementation of the

Mechanism and the submission of these revisions to the Mechanism for Commission approval after providing for notice and comment. Therefore, it is logical to begin the four-year period anew because it is in the public interest to gain operating experience with the proposed modifications before further reviewing the Mechanism as a whole. In addition, Piedmont projects that spending related to its Transmission Integrity and Distribution Integrity will continue well beyond the original four-year review period. Given these facts, Piedmont and the Public Staff propose to extend the operational review period for the revised Mechanism to match the period initially approved in the Rate Order for the initial Mechanism.

In regards to Question 4, Piedmont and the Public Staff state, as did CUCA, that the Stipulation would not eliminate the right of any party to petition the Commission to terminate or modify Piedmont's IMR mechanism at any time on the grounds that it is no longer in the public interest.

In response to Question 5, Piedmont and the Public Staff assert that changing to a bi-annual rate adjustment will benefit both Piedmont and ratepayers. Piedmont benefits from reducing regulatory lag and the ratepayers benefit by reducing the risk of multiple "pancaked" rate cases to roll incremental integrity management capital investment in rates.

JOINT REPLY COMMENTS OF PIEDMONT AND THE PUBLIC STAFF

On November 6, 2015, Piedmont and the Public Staff filed joint reply comments following a meeting between CUCA, Piedmont, and the Public Staff. As a result of the meeting, CUCA is satisfied with the explanations proffered by Piedmont and the Public Staff as to why the Stipulation represents a reasonable modification to Piedmont's IMR tariff and that CUCA no longer opposes the approval of the Stipulation subject to the commitments of Piedmont and the Public Staff to include CUCA in any future discussions.

In response to Question 1, Piedmont and the Public Staff maintain that the procedural processes for making bi-annual rate changes and conducting an annual IMR process in the spring of each year are appropriate and efficient and should not be modified by combining one or more of them with Piedmont's annual gas cost prudence review hearing.

In reference to Question 2, Piedmont and the Public Staff state that the audit of Piedmont's Integrity Management Plant Investment for the thirteen-month period October 2013 through October 2014 has been completed and the results of the audit are incorporated into the proposed settlement. Further, the audit reviewed Piedmont's calculations of its IMR costs and resulted in agreed levels of disallowed costs in both this audit period and future audit periods, thereby completing the regulatory process for this audit period and establishing parameters for future audit periods that are beneficial to Piedmont's customers.

In response to Question 3, Piedmont and the Public Staff assert that it is in the public interest to extend the specific IMR mechanism review date after a long sequence of discussions and interactions. The proposed settlement does limit the benefits to Piedmont of the IMR mechanisms through significant levels of cost disallowance, while seeking to preserve the fundamental benefit of the mechanism in expanding the interval between general rate case proceedings.

With respect to Question 4, Piedmont and the Public Staff, adding to their initial comments that the ability of any party to petition the Commission remains, state that they have recently met with CUCA to discuss its concerns with the proposed Stipulation and CUCA no longer objects to approval of the Stipulation.

In response to Question 5, Piedmont and the Public Staff contend that the change to a bi-annual rate adjustment is in the public interest, because the move to a bi-annual surcharge mechanism helps reduce regulatory lag while the presumptive cost disallowance provisions of the settlement provide substantial benefits to ratepayers on an ongoing basis.

DISCUSSION AND CONCLUSIONS

The Commission finds that the September 4, 2015 Stipulation filed by Piedmont and the Public Staff shall be treated as a petition to revise the Mechanism. Pursuant to Section 10 of the Mechanism, entitled Commission Review, "any interested party may petition the Commission to modify or terminate the Rider on the grounds that the Rider, as approved, is no longer in the public interest." The September 4, 2015 filing is such a petition requesting a modification of the Mechanism to serve the public interest.

In their petition, Piedmont and the Public Staff request that the Commission approve the Stipulation which (1) resolves the audit of Piedmont's Integrity Management Plant Investment for the thirteen-month period October 2013 through October 2014, as well as fiscal year 2015, and (2) amends the Mechanism by allowing Piedmont to adjust the IMR every six months rather than annually and provides for an annual review and opportunity for hearing.

Excluded Integrity Management Costs

Piedmont and the Public Staff provide in the Stipulation:

> WHEREAS, neither the Rate Case Stipulation nor Piedmont's tariff sets forth a procedural mechanism for Commission approval of Piedmont's IMR rate and the Public Staff has not yet completed its audit of Piedmont's Integrity Management Plant Investment for the thirteen month period October 2013 through October 2014, the rates for which went into effect pursuant to the Commission's Order Approving Rate Adjustments Effective February 1, 2014, issued February 5, 2014, in Docket No. G-9, Sub 641, and Order Approving Rate Adjustments Effective February 1, 2015, issued January 26, 2015, in Docket No. G-9, Subs 642 and 659 ("January 26, 2015 Order").
>
> WHEREAS, Piedmont and the Public Staff desire to resolve all issues between them resulting from the Public Staff's audit of Piedmont's Integrity Management Plant Investment for the thirteen months ended October 31, 2014, as well as all known issues between them related to the IMR mechanism for fiscal year 2015.

Stipulation, at 4-5.

As stated in the excerpts above, Piedmont and the Public Staff seek to resolve a review of a portion of Piedmont's integrity management costs for the period October 1, 2013 through October 31, 2014, as well as fiscal year 2015. In their reply comments, the Public Staff indicates that its audit reviewed Piedmont's calculations of its IMR costs and that this audit resulted in agreed levels of disallowed costs for this audit period as well as future audit periods. The Commission finds that this agreement was reached after the Public Staff obtained operating experience with the Mechanism. During the January 26, 2015 Staff Conference where the Public Staff presented the Mechanism to the Commission for approval, Jeff Davis testified that "we've done extensive work and extensive audits; … we've had to revise our sampling techniques and are working diligently with the Company to ascertain the prudence of these investments." Transcript, at 5-6. The result of this effort is that Piedmont and the Public Staff have agreed upon certain "excluded costs," which are described in the Stipulation:

> The Parties agree that certain costs associated with the Company's Integrity Management Plant Investment under the Company's "primary driver" test shall be excluded from recovery through the IMR mechanism ("Excluded Costs"). Those Excluded Costs shall be calculated by the following fixed percentages:
>
> - 30% of OASIS project costs allocated to North Carolina;
> - 3% of OASIS project costs allocated to North Carolina net of Excluded Costs from the previous bullet;
> - 85% of right-of-way clearing costs in TIMP and DIMP projects;
> - 10% of DIMP project costs net of Excluded Costs related to right-of-way clearing ("Net DIMP Excluded Costs"); and
> - 15% of TIMP project costs net of Excluded Costs related to right-of-way clearing ("Net TIMP Excluded Costs").

Stipulation, at 5.

This agreement to exclude certain costs reduces the amount of costs that are allowed to be recovered under the IMR as opposed to recovery in base rates. For example, the application of the agreement to exclude certain costs when applied to the thirteen-month period October 2013 through October 2014 and fiscal year 2015 will return to ratepayers the sum of $1,397,710. The costs excluded under the IMR may be considered in a general rate case.

The Commission agrees that ratepayers benefit by a reduction of costs allowed to be recovered through the IMR.

Bi-Annual Adjustments to Integrity Management Rider

In the Stipulation, Piedmont and the Public Staff request to change the Mechanism to allow Piedmont to adjust the IMR every six months and provide for an annual review and opportunity for hearing on the rate adjustments. In their joint comments, they contend that the two years of experience with the present Mechanism has shown that regulatory lag created by the annual procedure has been "relatively significant." Piedmont and the Public Staff assert that the proposed bi-annual surcharge mechanism would help reduce regulatory lag while the presumptive cost disallowance provisions discussed above provide substantial benefits to ratepayers.

The Commission agrees that the bi-annual surcharge mechanism creates benefits for both Piedmont and ratepayers. Piedmont benefits from reduction of regulatory lag and ratepayers benefit from increasing the time between general rate case filings in the face of federal integrity compliance requirements and the ability to review the adjusted rates during an annual review.

Finally, the Commission notes that although CUCA did not sign the Stipulation, CUCA does not oppose the Stipulation resolving this matter before the Commission.

Based upon the comments received herein, the Commission is of the opinion and concludes that it is in the public interest to accept the Stipulation subject to a filing by the Public Staff on or before February 29, 2016, of a report or review providing support for the exclusion determinations in the Stipulation. The Commission concludes that the Stipulation provides benefits to both Piedmont and its customers. Specifically, the agreement to exclude certain costs from cost recovery under the IMR provides benefits to ratepayers and the bi-annual adjustment benefits both Piedmont and ratepayers through the reduction of regulatory lag and increasing the time between general rate cases. These modifications to the IMR mechanism are in the public interest.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed in this proceeding on September 4, 2015, and the modifications filed on September 16, 2015, are accepted and Piedmont is authorized to implement the changes to its IMR tariff and procedures accordingly.

2. That the Public Staff will file a report or review providing support for the exclusion determinations in the Stipulation on or before February 29, 2016.

ISSUED BY ORDER OF THE COMMISSION.
This the __23rd__ day of November, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

DOCKET NO. P-75, SUB 76
DOCKET NO. P-76, SUB 65
DOCKET NO. P-60, SUB 84

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Joint Petition of Barnardsville Telephone Company, Saluda Mountain Telephone Company, Service Telephone Company, and RiverStreet Networks, LLC for Authorization to Provide Secured Payment Guarantees	)	ORDER AUTHORIZING EXECUTION OF GUARANTEE AND PLEDGE OF ASSETS

BY THE COMMISSION: On February 27, 2015, Barnardsville Telephone Company, Saluda Mountain Telephone Company, Service Telephone Company, and RiverStreet Networks, LLC, filed a verified Joint Petition, pursuant to G.S. 62-161 and Commission Rule R1-16, requesting that the three telephone company petitioners each be authorized to provide secured payment guarantees as to a loan to be made to their future parent, RiverStreet Networks, LLC, a wholly-owned subsidiary of Wilkes Telephone Membership Corporation.

Based upon the verified Joint Petition and the Commission's files and records, the Commission now makes the following:

FINDINGS OF FACT

1. Barnardsville Telephone Company ("Barnardsville") is a corporation duly organized and existing under the laws of the State of North Carolina. Barnardsville is an incumbent local exchange company ("ILEC") certificated by the Commission. Barnardsville provides telecommunications services in the Barnardsville exchange, which is located in Buncombe County.

2. Saluda Mountain Telephone Company ("Saluda") is a corporation duly organized and existing under the laws of the State of North Carolina. Saluda is an ILEC certificated by the Commission. Saluda provides telecommunications services in the Saluda exchange, which is located in Polk and Henderson Counties.

3. Service Telephone Company ("Service") is a corporation duly organized and existing under the laws of the State of North Carolina. Service is an ILEC certificated by the Commission. Service provides telecommunications services in the Fair Bluff exchange, which is located in Robeson and Columbus Counties.

4. Barnardsville Telephone Company, Saluda Mountain Telephone Company, and Service Telephone Company (collectively, the "North Carolina ILECs") are wholly-owned subsidiaries of TDS Telecommunications Corp. ("TDS Telecom"), a Delaware corporation.

5. RiverStreet Networks, LLC ("RiverStreet") is a limited liability company duly organized and existing under the laws of the State of North Carolina. RiverStreet is a wholly-owned subsidiary of Wilkes Telephone Membership Corporation ("Wilkes TMC"). Wilkes TMC is a telephone cooperative and a North Carolina non-profit corporation, headquartered in Wilkesboro, North Carolina. Wilkes TMC is an ILEC providing telecommunications services in the Boomer, Champion, Clingman and Lomax exchanges, which are located in and around Wilkes County, North Carolina. Wilkes TMC has provided telecommunications services in its service areas for over 60 years.

6. The North Carolina ILECs and Wilkes TMC operate in a highly competitive industry and business environment in which wireless, cable and over-the-top VoIP providers continue to expand their telecommunications offerings. Wilkes TMC and the North Carolina ILECs operate in an industry that has been and continues to be subject to rapid technological advances, evolving consumer preferences, and dynamic change. Based on those and other considerations, on December 30, 2014, TDS Telecom entered into three Stock Purchase Agreements whereby it agreed to sell 100% of the outstanding capital stock of each of the North Carolina ILECs to RiverStreet, which will result in Barnardsville, Saluda Mountain and Service becoming wholly-owned subsidiaries of RiverStreet Networks. RiverStreet's purchase of all stock of the North Carolina ILECs is hereinafter referred to as "the Acquisition."

7. The Acquisition will place ownership of the North Carolina ILECs in the hands of RiverStreet, a subsidiary of Wilkes TMC and an enterprise focused exclusively on the provision of services in rural areas of North Carolina. This transaction will improve the NC ILECs' collective financial condition, thereby allowing them to enhance their broadband capabilities, to accelerate their transition to IP networks, to pursue additional opportunities to strengthen their infrastructure, and to provide additional and enhanced services to customers.

8. After the Acquisition, the North Carolina ILECs will each continue to offer the same telecommunications services as they currently provide. Customers will continue to receive their existing telecommunications services at the same ates, terms, and conditions and any future changes in rates, terms or conditions of service will be consistent with any applicable provision of the North Carolina Public Utilities Act, the Commission's rules, and the price regulation plans which govern the North Carolina ILECs.

9. The planned transaction is expected to better position RiverStreet and the North Carolina ILECs to compete in the marketplace and provide telecommunication services to consumers in rural North Carolina at competitive rates. This transaction is expected to create new growth opportunities for the North Carolina ILECs, RiverStreet and Wilkes TMC, enabling them to take advantage of strategic, operational and financial opportunities.

10. G.S. 62-133.5(g) removes price regulated companies, such as the North Carolina ILECs, from the application of G.S. 62-111 which pertains to mergers, consolidations, and combinations of public utilities. However, the North Carolina ILECs are still required to obtain Commission authorization to provide the secured payment guarantees described in the Joint Petition.

11. CoBank, ACB ("CoBank" or "the lender"), has committed to provide a loan to RiverStreet for a portion of the purchase price to be paid to TDS Telecom for the outstanding stock of the North Carolina ILECs. A summary of CoBank's Terms and Conditions for that loan is Confidential Exhibit 1 to the Joint Petition.

12. As a condition of the loan to RiverStreet, the lender requires Wilkes TMC to provide an unsecured payment guarantee and grant a first priority lien on the capital stock of RiverStreet. The lender further requires the following:

> The Subsidiary Guarantors [the North Carolina ILECs] will provide a secured payment guarantee and will grant a first priority lien (subject only to exceptions approved in writing by CoBank) on all of their material real and personal property.

13. Thus, it is necessary for the North Carolina ILECs to provide secured payment guarantees (guarantees secured by liens granted to the lender) (collectively "the "Guarantees"), to CoBank as to the debt of their parent to-be, RiverStreet. The Guarantees will be contingent liabilities of each of the North Carolina ILECs. RiverStreet's debt will be served by the consolidated cash flows of RiverStreet, including cash flows resulting from RiverStreet's acquisition of the North Carolina ILECs as described herein.

14. The public convenience and necessity support the Acquisition as part of the establishment of a larger, North Carolina focused, independent, stand-alone wireline-centric operation that allows these ILECs to focus squarely on building their local wireline operations to provide a full range of high quality services to local residential and business customers. The execution of the Guarantees will facilitate the Acquisition, and the Acquisition will benefit the customers of the North Carolina ILECs in tangible ways. For example, RiverStreet plans to make significant investments to deploy Gigabit capable "fiber to the home" facilities in the service areas of all three of the North Carolina ILECs. That investment in those facilities will greatly enhance the ability of those ILECs' customers to secure enhanced broadband services, which will be a significant upgrade for these ILECs' service areas.

CONCLUSIONS

Based upon the foregoing Findings of Fact and the entire record in this proceeding, the Commission is of the opinion and so finds and concludes that the financing transaction proposed and described in the Joint Petition:

(i) is for a lawful object within the corporate purposes of the North Carolina ILECs;

(ii) is compatible with the public interest;

(iii) is necessary or appropriate for or consistent with the proper performance by the North Carolina ILECs of their service to the public as a utility;

(iv) will not impair the North Carolina ILECs' ability to perform their service to the public; and

(v) is reasonably necessary and appropriate for such corporate purpose.

IT IS, THEREFORE, ORDERED as follows:

That Barnardsville Telephone Company, Saluda Mountain Telephone Company and Service Telephone Company are hereby authorized and permitted to execute the Guarantees and related documents to secure the loan to be made to RiverStreet by CoBank. The approval given herein is limited to the execution of the documents necessary to guarantee the said loan and to pledge assets to secure the said Guarantees. Any lender or other party seeking to exercise any remedy under the Guarantees or as to the pledged assets of the North Carolina ILECs must petition the Commission for authority to take any such action.

Based on the foregoing, Barnardsville Telephone Company, Saluda Mountain Telephone Company and Service Telephone Company are hereby authorized:

(i) to execute the Guarantees and other related and necessary documents in connection with the loan to RiverStreet as described in the Joint Petition;

(ii) to pledge assets or otherwise create liens as part of the secured payment guarantees described in the Joint Petition, on the terms and conditions described therein; and

(iii) to execute and carry out such instruments, documents and agreements as shall be necessary or appropriate in order to effectuate the financing transaction described in the Joint Petition.

IT IS FURTHER ORDERED that the proceeds resulting from the financing transaction described in the Petition shall be used for the purposes described in the Joint Petition.

ISSUED BY ORDER OF THE COMMISSION
This the 17th day of March, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. T-4569, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Dwight Dion Williams, d/b/a Meek Movers, 652 Connors Cove, Hope Hills, North Carolina 28348 - Application for Certificate of Exemption to Transport Household Goods	))))	ORDER RULING ON FITNESS AND SHOW CAUSE PROCEEDING

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, Thursday, June 18, 2015, at 10:00 a.m.

BEFORE: Commissioner Bryan E. Beatty, Presiding, Chairman Edward S. Finley, Jr., and Commissioner Don M. Bailey

APPEARANCES:

For Dwight Dion Williams, d/b/a Meek Movers:

Dwight Dion Williams, 652 Connors Cove, Hope Hills, North Carolina 28348 (pro se)

BY THE COMMISSION: On March 31, 2015, Dwight Dion Williams, d/b/a Meek Movers (the Applicant), filed an application with the Commission for a certificate of exemption to transport household goods by motor vehicle for compensation within the State of North Carolina. The application identified Dwight Dion Williams as the sole proprietor.

On April 14, 2015, the certified criminal history record check for the Applicant was filed with the Commission as required by G.S. 62-273.1 and Commission Rule R2-8.1(a)(3).

On May 14, 2015, the Commission issued an Order Scheduling Hearing for June 18, 2015, requiring the Applicant to appear before the Commission to discuss Meek Movers' application for a certificate. The Order also provided that the Public Staff – North Carolina Utilities Commission (Public Staff) may participate in the hearing on behalf of the using and consuming public.

On May 28, 2015, the Commission issued an Order Providing Notice of Show Cause notifying the Applicant that the Commission had reason to believe that, he has been advertising services as a household goods mover to the using and consuming public without first being issued a certificate to operate as a carrier of household goods in violation of G.S. 62-280.1. As a result of this information, the Commission required the Applicant to appear and show cause why he should not be assessed a civil penalty if he is found to have violated North Carolina law and Commission rules.

On June 12, 2015, Lucy E. Edmondson, Staff Attorney, filed a letter on behalf of the Public Staff informing the Commission that the Public Staff did not intend to participate in the hearing on behalf of the using and consuming public.

On June 17, 2015, Dwight Dion Williams filed three character reference letters to be considered by the Commission. These letters were from Minister Kelvin Williams, Iris Blocker, and Deatrice Harris.

On June 18, 2015, the hearing was held as scheduled. Dwight Dion Williams appeared pro se to provide testimony in support of the Applicant's application for a certificate.

Based upon the testimony and the exhibits presented at the hearing, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. On March 31, 2015, Dwight Dion Williams, d/b/a Meek Movers filed an application for a certificate of exemption to operate as a household goods mover in the State of North Carolina. The application identified Dwight Dion Williams as the sole proprietor of the business.

2. The Commission has jurisdiction over public utilities, including those engaged in the intrastate transportation of household goods for compensation in North Carolina, as defined by G.S. 62-3(7) and (15).

3. Applicants who seek to perform intrastate transportation of household goods for compensation in North Carolina must obtain a certificate pursuant to G.S. 62-261(8) and Commission Rule R2-8.1.

4. Meek Movers is properly before the Commission pursuant to Commission Rule R1-4(3).

5. The Applicant has filed the required confidential criminal history record check and has sufficiently addressed all the questions that the Commission had about his criminal history.

6. The Applicant is originally from the State of New York. He relocated to Fayetteville, North Carolina, when he was 32 years old. He got involved with the household goods moving business when he was 16 years old. He has amassed over fifteen (15) years of experience working with moving companies in both New York and North Carolina. Over the years, he has learned how to load, unload, supervise work crews, and complete bills of laden.

7. The Applicant has advertised his moving services on a business webpage (http://meekmovers.com/), Yelp, Craigslist, Facebook, and Yellowpages.com. In the advertisements, the Applicant states that he is a full service mover authorized to perform residential moves in the State of North Carolina. The advertisements specifically state that he is a member of the North Carolina Movers' Association and has a certificate from the Commission.

8. The Commission provided notice to the Applicant that he may have violated North Carolina law and/or Commission rules. He was also advised that he could be assessed a civil penalty pursuant to G.S. 62-280.1, recoverable pursuant to G.S. 62-312[1].

9. The Applicant admits that he has advertised his moving services on the internet. He further admits that much of the information in his advertisements is false. Specifically, he admits that he is not a member of the North Carolina Movers' Association nor does he have a certificate from the Commission.

10. As of the date of the hearing, the Applicant still advertised his moving services on the internet through a business webpage, Yelp, Facebook, Craigslist, and Yellowpages.com.

11. The Applicant violated G.S. 62-280.1 when he advertised on several web sites that he is a certificated carrier that offers his customers residential moving services, that he is a member of the North Carolina Movers' Association, and that he holds a certificate from the Commission. The advertising was initiated although the Applicant did not possess a certificate for the Commission.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

(1) Whether the Applicant's background and other fitness issues preclude Meek Movers from being issued a certificate?

The record shows that the Applicant is the sole manager of the moving business. The Applicant started the business in 2014 as an avenue to secure additional income. He has a wife and three minor children that he supports. He testified that, at the present time, the Applicant does not have any salaried employees. He utilizes the assistance of several reliable individuals when he schedules moving jobs. In preparation for operating his business, the Applicant purchased a 1995 Ford F700 Box Truck and secured insurance. The vehicle is currently parked until he obtains his certificate and can secure authorization from the North Carolina Department of Motor Vehicles.

The record further shows that the Applicant possesses over fifteen years of experience in the household goods moving industry. He began his involvement with the moving industry when he was 16 years old. During that time, he worked with his uncle's moving company in New York. He also gained moving experience working with GiGi's Moving Company in Long Island, New York. His involvement with the moving industry continued after he relocated to North Carolina when he was 32 years old. From 2009 until 2014, the Applicant worked for Andy Anderson Moving & Storage in

[1] G.S. 62-312 allows the Commission to initiate recovery of any penalty under this Chapter in Wake County Superior Court.

Fayetteville, North Carolina. He worked with this company loading, unloading, supervising moving crews, and completing bills of laden.

In determining the Applicant's fitness to obtain a certificate, the Commission not only reviews the Applicant's background and knowledge of the moving industry, but it also considers his criminal history. After an extensive review, the Commission finds and concludes that the Applicant has sufficiently addressed the Commission's questions such that his employment background and criminal history does not call into question his fitness to possess a certificate from the Commission. Therefore, the Commission finds and concludes that the Applicant should not be denied an opportunity to receive a certificate to transport household goods in the State of North Carolina due to his employment background and criminal history.

(2) Whether the Applicant should be subject to sanctions and/or penalties as provided by G.S. 62-280.1(c), for advertising his services on the internet as a household goods carrier to the public without first having been issued a certificate of exemption from the Commission?

The facts in the record support the finding that the Applicant violated North Carolina law by advertising his moving services without first obtaining a certificate from the Commission. The testimony and other evidence supporting this finding are undisputed. The Applicant advertised his moving services to the using and consuming public on the internet through a business webpage (http://meekmovers.com/), Yelp,[1] Craigslist,[2] Facebook,[3] and Yellowpages.com.[4] During the hearing, the Commission reviewed copies of advertisements from each of the above internet sites as of May 15 – 27, 2015. In each of his advertisements, the Applicant states that he is a full service mover authorized to perform commercial and residential moves in the State of North Carolina. The Applicant's webpage specifically states that "Meek Movers has over 20 years experience in the moving industry and we are members of the North Carolina Movers Association;" also, "We currently hold a Certificate to Transport Household Goods issued by the North Carolina Utilities Commission and we are fully insured with all of the insurance required by the State of North Carolina." The Commission determined that at the time the internet sites were reviewed, the

[1] Yelp is an internet site that provides the public with customer reviews of businesses and services.

[2] Craigslist is a free on-line service that allows members of the public to post classified ads for services, including, but not limited to, housing, moving, and employment.

[3] Facebook is a social networking website that allows its participants to share information with other account holders.

[4] Yellowpages.com allows potential customers to search on-line for information on business services.

Applicant did not possess a certificate to perform residential moves. The record clearly shows that the Applicant filed his application with the Commission on March 31, 2015, but that a certificate had not been issued even as of the date of the hearing. The Commission further determines that the information that was publicized to the using and consuming public is false. During cross-examination, the Applicant admitted that the statements in his advertisements are false. Specifically, the Applicant admitted that he is not a member of the North Carolina Movers' Association and that he is not certificated by the Commission to perform household goods moves in the State of North Carolina.

General Statute Section 62-280.1, in pertinent part, expressly states that it is unlawful for a person not issued a certificate by the Commission to operate as a carrier of household goods to orally, in writing, in print, or by sign, including the use of a vehicle placard, phone book, Internet, magazine, newspaper, billboard, or business card, or in any other manner, directly or by implication, represent that the person holds a certificate or is otherwise authorized to operate as a carrier of household goods in this State.

The record shows that the Applicant advertised his moving services despite being notified by Commission staff that he could not do so until he received a certificate from the Commission. On April 1, 2015, Nicholas Jeffries, Commission transportation analyst, sent the Applicant written correspondence acknowledging that his application was received by the Commission. The correspondence further advises that the Applicant is prohibited from engaging in any residential moving activities including advertising until a certificate is issued by the Commission. The Applicant admitted at the hearing that he received this correspondence from the Commission and that he was aware that he was not to advertise his moving services. Despite this acknowledgement, the Applicant continued to advertise his services to the using and consuming public. The Applicant maintains that his actions violating North Carolina law were not intentional, but inadvertent. He asserts that he believed that the application process would be swift and that there would be no delay in assigning him a certificate. The Applicant submitted the advertising information to the Internet sites believing that he would have his certificate by the time the material was actually published. Additionally, he asserts that he did not intend to mislead the using and consuming public in his advertisements. Instead, he claims that he did not know exactly what information he could use in the advertisement, but that he wanted the public to know that he could provide a wide variety of services.

The Commission recognizes that the Applicant may have gotten ahead of himself by prematurely beginning his advertising campaign. The Commission, however, cannot overlook the fact that the Applicant is still advertising while he is not yet certificated by the Commission. The facts show that the Applicant's actions were done at a time when he was clearly notified by the Commission that advertising his services would violate North Carolina law. Moreover, the information used by the Applicant in his advertisements is false. The Applicant has not presented any reasonable justification for his actions in this matter.

Based on the foregoing, the Commission finds and concludes that the Applicant's actions are willful and, thus, in violation of North Carolina law. Pursuant to G.S. 62-280.1(c),[1] the Commission finds and concludes that the Applicant should be levied a monetary fine of one thousand dollars ($1,000) in United States currency for his violation of G.S. 62-280.1. The fine will be payable to the Commission through a total of five monthly payments of two hundred dollars ($200) each beginning fifteen (15) days after the issuance of this Order. If the Applicant does not comply with the levied monetary sanctions, the Commission will take appropriate action pursuant to G.S. 62-312 to recover the fine and to suspend the Applicant's certificate. Once the Applicant has completed his monetary obligation, the Commission will issue an Order Confirming Satisfaction and Closing Proceeding. The Applicant is not to operate as a household goods mover until granted a certificate from this Commission. The Applicant's certificate will be issued by separate Order once he complies with all the necessary requirements.

IT IS, THEREFORE, ORDERED as follows:

1. That Dwight Dion Williams, d/b/a Meek Movers is fit, willing, and able to perform services as a household goods mover.

2. That the Applicant will pay a total monetary fine of one thousand dollars ($1,000) in United States currency to the Commission for violation of G.S. 62-280.1. This monetary fine will be due in five equal monthly installments of two hundred dollars ($200), with the first to be paid within fifteen (15) days after the issuance of this Order. The remaining payments will be due each month on the same day of the month as the previous payments.

3. That this proceeding will remain open until the Applicant fully completes his financial obligation under the Order. Once this obligation is fulfilled, the Commission will issue an Order Confirming Satisfaction and Closing Proceeding.

4. That this Order will be served on Dwight Dion Williams, d/b/a Meek Movers, by United States certified mail, return receipt requested and electronic mail (e-mail), delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of July, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

[1] Subsection (c) of G.S. 62-280.1, allows the Utilities Commission to assess a civil penalty not in excess of five thousand dollars ($5,000) for the violation of subsection (a) of this section. The clear proceeds of any civil penalties collected pursuant to this subsection shall be remitted to the Civil Penalty and Forfeiture Fund in accordance with G.S. 115C-457.2.

DOCKET NO. T-4523, SUB 0
DOCKET NO. T-4523, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. T-4523, SUB 0 In the Matter of Pick Up & Go Moving International, Inc., 9815 J Sam Furr Road, Suite 27, Huntersville, North Carolina 28078 – Application for Certificate of Exemption and DOCKET NO. T-4523, SUB 1 In the Matter of S.J. (Bill) Hopper, 3333 Knighton Lane, Gastonia, North Carolina 28056, Complainant v. Pick Up and Go Moving International, Inc., 9815 J Sam Furr Road, Suite 27, Huntersville, North Carolina 28078, Respondent	ORDER GRANTING MOTION TO WITHDRAW APPLICATION FOR CERTIFICATE OF EXEMPTION AND ACCEPTING STIPULATED SETTLEMENT

HEARD: Tuesday, December 2, 2014, at 10:00 a.m., Gaston County Courthouse, 325 N. Marietta Street, Courtroom 4D, Gastonia, North Carolina.

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Commissioner Susan W. Rabon and Commissioner Don M. Bailey.

APPEARANCES:

For the Applicant/Respondent:

Zachary M. Moretz, Moretz & Skufca, PLLC, 37 Union Street South, Suite B, Concord, North Carolina 28025.

For Complainant:

S. J. (Bill) Hopper, pro se, 333 Knighton Lane, Gastonia, North Carolina 28056

For the Using and Consuming Public:

Lucy Edmondson, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Dobbs Building, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On September 30, 2013, Pick Up & Go Moving International, Inc., (Applicant or Respondent) filed an application in Docket No. T-4523, Sub 0, with the North Carolina Utilities Commission (Commission) for a Certificate of Exemption (Certificate) to transport household goods pursuant to North Carolina General Statute 62-261(8) and Commission Rule R2-8.1.

On October 16, 2013, Commission staff filed a copy of correspondence to Respondent returning Application. The Application was returned to Respondent because it was incomplete.

On November 21, 2013, the certified criminal history record check of Kimberly Maddox was filed with the Commission. The same day, Respondent filed an amendment to its originally submitted Application. The amended Application named Antoine Johnson and Kimberly Maddox as the Respondent's principals.

On November 27, 2013, the certified criminal history record check of Antoine Johnson was filed with the Commission.

On April 28, 2014, S. J. (Bill) Hopper (Complainant) filed a complaint in Docket No. T-4523, Sub 1, with the Commission against Respondent alleging that Respondent unsatisfactorily performed a household goods move for him and seeking, among other things, reimbursement, return of undelivered items, removal of damaged items, assessment of applicable penalties, and the denial of a certificate of exemption to Respondent.

On May 1, 2014, the Commission issued an Order Serving Complaint.

On May 7, 2014, Respondent filed its Answer to the Complaint. The Answer was served on Complainant by Order of the Commission on May 9, 2014.

On May 19, 2014, Complainant filed his Response with the Commission indicating that he was not satisfied with Respondent's Answer. Complainant's Response was served on Respondent by Order of the Commission on May 28, 2014.

On August 14, 2014, the Commission in Docket No. T-4523, Sub 1 issued an Order Scheduling Hearing, Clarifying Issues for Hearing, and Dismissing Claim, In Part. The hearing was scheduled to be heard on September 23, 2014, in Gastonia, North Carolina.

On August 26, 2014, the Commission in Docket No. T-4523, Sub 0 issued an Order Scheduling Hearing and Consolidating Dockets. The Commission consolidated Docket Nos. T-4523 Sub 0 (Application) and Sub 1 (Complaint) for hearing. The hearings in the consolidated dockets ("the proceedings") were scheduled for the same date and time.

On September 16, 2014, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a Notice of Intervention in the proceedings and a Motion for Disclosure of Respondent's Answer to the Complaint matter, which had been marked as confidential.

On September 19, 2014, newly retained counsel for Respondent contacted the Commission and made an oral request to continue the hearing date.

On September 22, 2014, the Commission issued an Order Granting Oral Motion for Continuance and Postponing Hearings.

On October 8, 2014, the Commission issued an Order Scheduling Hearings. The proceedings were rescheduled for hearing on December 2, 2014, at 10:00 a.m., Gaston County Courthouse, Courtroom 4D, Gastonia, North Carolina.

On December 1, 2014, the Commission issued an Order Granting Public Staff's Motion for Public Disclosure.

On December 2, 2014, the hearing came on as scheduled. Complainant appeared, pro se, to testify and present exhibits in support of his claims. Zachary M. Moretz, Esq., appeared on behalf of Respondent. Antoine Johnson, Respondent's President, also attended in support of Respondent. Lucy Edmondson, Esq., of the Public Staff appeared on behalf of the using and consuming public.

On December 23, 2014, the Public Staff filed a Motion for an Extension of Time to File Proposed Orders. The Public Staff's Motion was granted by Commission Order on December 29, 204.

On January 7, 2015, the Public Staff filed its Proposed Order.

WHEREUPON, the Commission makes the following:

CONCLUSIONS

At the hearing before the presentation of evidence, Respondent moved to withdraw its Application for a certificate of exemption, stating it no longer planned to perform intrastate household goods moves. The motion was unopposed by the Public Staff and it was granted by the Presiding Commissioner from the bench. Complainant then took the stand, testified and presented evidence in support of his case. After a break in the proceedings, the hearing resumed and the Public Staff, Complainant, and Respondent (hereinafter, "the parties") reported that they had reached an agreed upon settlement. The basic terms of the Stipulated Settlement (Stipulation) were reported on the record and the parties were requested by the Presiding Commissioner to reduce the terms of the Stipulation in proposed order form and to file it with the Commission. On January 7, 2015, the parties filed the proposed order with the Commission. The Commission has reviewed the proposed order and makes the following findings and conclusions.

Pursuant to the terms of the Stipulation, Respondent withdraws its Application for a certificate of exemption from the Commission. Respondent also agrees to undertake the following specified actions to remedy the harms created during its move of Complainant's household goods: On December 2, 2014, pay Complainant $150.00, as reimbursement for Complainant's overpayment of storage fees and return to Complainant the base of his Tiffany lamp; and remove the armoire damaged in its move of Complainant's household goods from Complainant's garage on December 6, 2014, at 10:00 a.m. Respondent further agrees to return the $1,300.00 owed to Marie Roawden as alleged in a separate complaint filed in Docket No. T-4523, Sub 2. The parties have represented to the Commission that Respondent completed the above-stated specified actions prior to the filing of the parties' proposed order on January 7, 2015.

The Stipulation also states that Respondent admits that it acted as a de facto public utility by holding itself out as a common carrier of household goods, as defined in G.S. 62-3(7), while engaging in the intrastate transport of household goods without possessing a certificate of exemption as required by G.S. 62-262(a). Specifically, Respondent visited Complainant's home and offered its services as a certificated carrier. Respondent negotiated its compensation and moved Complainant's household goods. At the time that the move was performed, Respondent did not possess a certificate of exemption from the Commission to engage in intrastate household goods moving.

Respondent further admits that it represented itself as being authorized to operate as a carrier of household goods in North Carolina in violation of G.S. 62-280.1(a). Specifically, Respondent violated North Carolina Law and Commission Rules by maintaining a website that advertises that it performs household goods moves in the state of North Carolina. The advertisement suggests that Respondent is certificated by the Commission to perform intrastate household goods moves. The advertisement produced by Respondent is false and misleading. Respondent has not been issued a certificate of exemption from the Commission. Because this information is false and violates North Carolina Law and Commission Rules, Respondent agrees that within 30 days of this Order, it will remove from its website and attempt to have removed from websites owned by other parties, any advertising that indicates or suggests that it provides the intrastate transport of household goods.

Based on the admissions above, the Commission finds and concludes that Respondent's actions were clear violations of Commission Rule R2-8.1 and G.S. 62-262(a), which prohibit it from acting as a de facto public utility by holding itself out as a common carrier of household goods, as defined in G.S. 62-3(7), while engaging in the intrastate transport of household goods without possessing a certificate of exemption. The Commission further finds and concludes that Respondent's actions were violations of G.S. 62-262(a) and G.S. 62-280.1, which prohibit an entity from representing that it is authorized to perform intrastate household goods moves without first obtaining a certificate of exemption from the Commission and from advertising that it provides such moving services in the absence of such certification.

The Stipulation also provides that Respondent agrees to pay monetary fines for its violations of North Carolina Law and Commission Rules. In particular, Respondent agrees to pay two thousand, five hundred dollars **($2,500.00)** in United States currency to the Commission for acting as a de facto public utility by holding itself out as a common carrier of household goods, as defined in G.S. 62-3(7) and by engaging in the intrastate transport of household goods without possessing a certificate of exemption as required by G.S. 62-261(8) and Commission Rule R2-8.1 in violation of G.S. 62-262(a). Respondent further agrees to pay one thousand dollars **($1,000.00)** in United States currency to the Commission for representing itself as being authorized to operate as a carrier of household goods in North Carolina in violation of G.S. 62-280.1(a). These civil penalties totaling three thousand, five hundred dollars **($3,500.00)** will be paid in seven payments of five hundred dollars ($500.00); the first due and payable within fifteen days of this Commission order, with the successive payments of five hundred dollars ($500.00) due on the same day of each following month.

In this case, the Commission supports the assessment of monetary penalties against Respondent's admitted illegal actions. The Commission considers the assessment of monetary fines an effective mechanism to deter others from engaging in such unlawful behavior. The Commission notes, however, that had Respondent not agreed to the stated fines, it faced the possible imposition of greater fines and/or other sanctions for its violations of North Carolina Law and Commission Rules.

The Commission admonishes Respondent and its principals to abide by all applicable laws and the rules and regulations of the Commission. In the future, should the Commission have reason to believe that the Respondent has engaged or is engaging in any further unauthorized activities, the appropriate compliance and enforcement steps will be taken. The Commission takes its obligation to protect the using and consuming public from uncertificated and/or offending movers seriously. The Commission will continue to pursue enforcement of its rules and North Carolina Law, particularly where there is sufficient evidence establishing that entities have ignored the advice and guidance of the Public Staff and/or have not acted in a timely manner to remedy potential violations.

After reviewing the entire record and the parties' Stipulated Settlement, the Commission finds and concludes that the terms and conditions, including the monetary fines contained therein, are reasonable and accepts the Stipulation as filed. The Commission will monitor Respondent's compliance and once all the terms are met, an Order will be issued dismissing the proceedings and closing the dockets.

IT IS, THEREFORE, ORDERED as follows:

1. That Respondent's motion to withdraw its Application for a Certificate of Exemption filed in Docket No. T-4523, Sub 0 is hereby granted.

2. That Respondent will take the following remedial actions with regard to the move it performed for Complainant:

- On December 2, 2014, pay Complainant $150.00 as reimbursement for Complainant's overpayment of storage fees and return to Complainant the base of his Tiffany lamp; and

- Remove the armoire damaged in its move of Complainant's household goods from Complainant's garage on December 6, 2014, at 10:00 a.m.

[The parties have represented to the Commission that the conditions shown above have already been met. These conditions are included in this Order because they were originally agreed to in the Stipulated Settlement.]

3. That Respondent return the $1,300.00 owed to Marie Roawden as alleged in her complaint filed in Docket No. T-4523, Sub 2. [The parties have represented to the Commission that this condition has already been met. The condition is included in this Order because it was an originally agreed to in the Stipulated Settlement.]

4. That Respondent will pay a total monetary fine of three thousand, five hundred dollars ($3,500.00) in United States currency to the Commission. The total fine represents two thousand, five hundred dollars ($2,500.00) for violation of G.S. 62-262(a) and one thousand dollars ($1,000.00) for violation of G.S. 62-280.1. <u>This monetary fine will be paid in seven equal installments of five hundred dollars ($500.00); the first is to be paid fifteen days after issuance of this Order. The remaining payments will be due monthly on the same day of the subsequent months</u>.

5. That these proceedings will remain open until Respondent fully completes its financial obligations under the Stipulation. Upon fulfillment of these obligations, the Commission will issue an Order Dismissing the proceedings and closing the dockets.

6. That this Order will be served on both Complainant and Respondent by United States certified mail, return receipt requested and electronic mail (e-mail), delivery confirmation requested.

7. That this Order will be served on the Public Staff by e-mail, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the _13th_ day of February, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. T-4562, SUB 0
DOCKET NO. T-4562, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. T-4562, SUB 0 In the Matter of The Application for Certificate of Exemption to Transport Household Goods by Sandhills Moving & Storage, Co., DOCKET NO. T-4562, SUB 1 In the Matter of Darlene S. Bodnar, Complainant v. Sandhills Moving & Storage, Co., Respondent	)	RECOMMENDED ORDER DISMISSING COMPLAINT AND ACCEPTING CONSENT AGREEMENT

BY HEARING EXAMINER FOSTER: On January 23, 2015, Sandhills Moving & Storage, Co. (Applicant or Sandhills), filed an application for Certificate of Exemption (certificate) to Transport Household Goods. The application was assigned to Docket No. T-4562, Sub 0.

On March 11, 2015, Darlene S. Bodnar (Complainant) filed with this Commission a complaint against Sandhills alleging the company performed a move of her household goods without possessing a certificate from the Commission and that Sandhills is responsible for a 1.5-carat, three-stone diamond ring (diamond ring) that was missing from one of her moving boxes. The complaint was assigned to Docket No. T-4562, Sub 1.

On March 27, 2015, the Commission issued an Order Serving Complaint.

On April 8, 2015, Sandhills filed its Answer to the Complaint. The next day, the Commission issued an Order Serving Answer.

On April 20, 2015, Complainant filed her Response to Sandhills' Answer. In her Response, she informed the Commission that she was not satisfied with Sandhills' Answer and desires to see the company fined for the unauthorized move that it performed for her.

On July 27, 2015, the Commission issued an Order Consolidating Dockets, Providing Notice of Show Cause, and Scheduling Hearing. In the Order, the Commission consolidated the Application in Docket No. T-4562 Sub 0 and Complaint in Docket No. T-4562, Sub 1 for hearing. The hearings in the consolidated dockets (hereinafter, the proceedings) were scheduled for the same date and time on Tuesday, August 18, 2015, at 10:00 a.m., in Raleigh, North Carolina. The Order further provided Sandhills notice that it was required to appear and address the issue of whether it violated G.S. 62-261(8) and Commission Rule R2-8.1 by performing a move of household goods without possessing a certificate from the Commission and whether it should be assessed a civil penalty pursuant to G.S. 62-310 if it is found to have violated North Carolina Law and/or Commission Rules. Lastly, the Commission invited the Public Staff – North Carolina Utilities Commission (Public Staff) to participate in the proceedings on behalf of the using and consuming public.

On August 10, 2015, the Public Staff and Sandhills (collectively, the Parties), filed a Consent Agreement and Motion to Cancel Hearing. The hearing was canceled by order of the Commission on August 11, 2015.

WHEREUPON, the Commission makes the following:

CONCLUSIONS

The Hearing Examiner has reviewed the Consent Agreement filed by the Parties in these proceedings and makes the following findings and conclusions with regard to the Agreement executed by the Parties. Pursuant to the Consent Agreement, the Parties admit that they were unable to get the Complainant to participate in settlement negotiations. In fact, Complainant informed the Public Staff that she would not attend the evidentiary hearing scheduled on August 18, 2015, in Raleigh, North Carolina. Complainant's position is that she has presented sufficient evidence in her initial pleading to support her claim against Sandhills and therefore, she did not intend to appear at the hearing.

The Parties also admit that on October 13, 2014, due to medical problems requiring several medical procedures, Richard Rudig, President of Sandhills, inadvertently allowed its certificate issued in Docket No. T-1852 to lapse. As a result of the lapse, the Commission issued an Order Affirming Previous Commission Order Cancelling Certificate[1] in Docket Nos. T-1852, Sub 11 and T-100, Sub 96. Service of the Commission's Order was accepted by Mrs. Pat Rudig, Sandhills' Vice President. The Public Staff asserts that when Sandhills did possess a valid certificate, the company had a satisfactory record of operations.

The Parties further admit that on October 24, 2014, Sandhills moved the Complainant's household goods for compensation from Vass, North Carolina, to West End, North Carolina. After the move was performed, the Complainant discovered that a diamond ring was missing from one of her moving boxes. Sandhills continues to deny any responsibility for the missing diamond ring.

[1] The Commission previously assigned Sandhills Moving & Storage Co., Certificate of Exemption No. C-865.

On January 23, 2015, Sandhills, pursuant to G.S. 62-261(8) and Commission Rule R2-8.1, filed an application with the Commission for a certificate to transport household goods by motor vehicle for compensation within North Carolina. The application was assigned to Docket No. T-4562, Sub 0. During this time, the Complainant was still unable to get Sandhills to take responsibility for her missing ring. Therefore, on March 11, 2015, the Complainant filed a complaint with the Commission against Sandhills in Docket No. T-4562, Sub 1. The Public Staff points out that the Complainant's informal complaint involved seeking restitution from Sandhills for her missing diamond ring. Now in her formal complaint, she is seeking that Sandhills be punished for its illegal move of her household goods.

Per the terms of the Consent Agreement, Sandhills admits that it moved the Complainant's household goods from Vass, North Carolina, to West End, North Carolina, on October 24, 2014, in violation of G.S. 62-261(8) and Commission Rule R2-8.1. As a result of this violation of North Carolina Law and Commission Rules, Sandhills agrees to pay a fine of one thousand dollars ($1,000.00) in United States currency to the Commission, no later than ten days after the issuance of the Order Accepting Consent Agreement.[1]

The Hearing Examiner understands that the Complainant's initial relief in this matter included restitution for her missing diamond ring. The Commission, however, does not possess jurisdiction to grant monetary damages in complaint proceedings such as this one. In order for the Complainant to obtain any relief related to her diamond ring, she will have to pursue her matter in a Court of General Justice in her county. Additionally it is clear, considering Complainant's statements and other interaction with the Public Staff that she will not attend or otherwise participate in the evidentiary hearing. Given the information provided above, the Hearing Examiner finds that good cause exists to dismiss the Complaint proceeding in this matter.

The Hearing Examiner, however, supports the assessment of a monetary penalty against Sandhills based on its admitted illegal activity. The Commission's records show that at one time Sandhills did possess a valid certificate to operate in the state. Unfortunately, Sandhills allowed the certificate to go into a state of suspension and then eventual revocation. There is nothing in the record to show or suggest that Sandhills took any remedial steps to protect the status of its certificate or to avoid violating North Carolina Law and/or Commission Rules. Based on the admissions in the Consent Agreement, it is now uncontroverted that Sandhills performed a move of household goods for compensation when it did not possess a valid certificate.

The Hearing Examiner recognizes that the Commission takes allegations of companies and/or individuals performing unauthorized intrastate moves very seriously. In response to these illegal actions, the Commission has consistently assessed fines and other sanctions upon entities that it has found violated North Carolina Law and/or Commission Rules. In this case, the Hearing Examiner finds that the proposed fine of one thousand dollars ($1,000.00) is reasonable and consistent with similar fines assessed by the Commission in other household goods proceedings. The Hearing Examiner, however, should acknowledge that if an evidentiary hearing was held, additional and more stringent conditions could have been imposed upon Sandhills.

[1] The proceeds from civil penalties paid to the Commission go to the county for public schools.

The Hearing Examiner is encouraged that Sandhills accepts the severity of its actions in these proceedings. Through its participation in the Consent Agreement, Sandhills is showing that it is attempting to provide its moving services to the using and consuming public in a lawful manner. Moreover, Sandhills renews its commitment to abide by all applicable North Carolina Laws and Commission Rules going forward. Sandhills further clarifies to the Commission that the Consent Agreement shall not be construed to deprive any consumer or other person or entity of any private right under the law. This particular condition has significant importance as it will not preclude the Complainant from seeking restitution from Sandhills for her missing diamond ring in a Court of General Justice.

Based upon the foregoing, the Hearing Examiner finds and concludes that good cause exists to accept the Consent Agreement executed by the Parties and filed with the Commission on August 10, 2015. The Hearing Examiner further finds and concludes that good cause exists to take no further action in these proceedings until such time that Sandhills fulfills its obligation under the Consent Agreement. Upon the fulfillment of this financial obligation, the Commission will issue an Order Dismissing the Proceedings.

IT IS, THEREFORE, ORDERED as follows:

1. That the Consent Agreement filed with the Commission on August 13, 2015, in these proceedings is hereby accepted.

2. That the Complaint proceeding filed in Docket No. T-4562, Sub 1 by Darlene S. Bodnar is hereby dismissed.

3. That Sandhills Moving & Storage Co., is found to have violated G.S. 62-261(8) and Commission Rule R2-8.1 and will pay a total of one thousand dollars ($1,000.00) in United States currency to the North Carolina Utilities Commission, in one lump sum, no later than ten days after the issuance of this Order.

4. That if Sandhills Moving & Storage Co., does not comply with its financial obligation as described in the Consent Agreement, the Commission may take further action against the company pursuant to G.S. 62-310.

5. That this Order will be served on Darlene Bodnar and Sandhills Moving & Storage, Co., by United States certified mail, return receipt requested and on the Public Staff by electronic mail (e-mail), delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of August, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

DOCKET NO. W-218, SUB 408
DOCKET NO. W-1149, SUBS 8 AND 9

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, and Water Works of Alamance County, Inc., Post Office Box 1075, Graham, North Carolina 27253, for Authority to Transfer the Timberlake and Thornton Ridge Subdivisions Water System and Franchise in Alamance County, North Carolina, and Approval of Rates	))))))))	RECOMMENDED ORDER APPROVING TRANSFER, ACQUISITION ADJUSTMENT, AND RECOGNIZING CONTIGUOUS EXTENSION

HEARD IN: 7:00 p.m., Thursday, July 16, 2015, in the Alamance County Government Commissioner's Chambers, 124 West Elm Street, Graham, North Carolina

BEFORE: Ronald D. Brown, Hearing Examiner

APPEARANCES:

For Aqua North Carolina, Inc.:
Jo Anne Sanford, Sanford Law Office, PLLC, Post Office Box 28085, Raleigh, North Carolina 27611

For Water Works of Alamance County, Inc.:
Charlotte A. Mitchell, Law Office of Charlotte Mitchell, Post Office Box 26212, Raleigh, North Carolina 27611

For the Using and Consuming Public:
William E. Grantmyre, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BROWN, HEARING EXAMINER: On February 26, 2015, Aqua North Carolina, Inc. (Aqua), and Water Works of Alamance County, Inc. (Water Works), filed a verified application (the Application) for authority to transfer the Timberlake and Thornton Ridge Subdivisions water system assets and franchise in Alamance County from Water Works to Aqua and approval of increased rates. The service area consists of Timberlake Subdivision, Phase 1, and a contiguous area, Thornton Ridge Subdivision. On February 25, 2015, in Docket No. W-1149, Sub 8, Water Works filed a notification of intention (the Notification) to begin water utility operations in Thornton Ridge Subdivision, which is contiguous to the Timberlake Subdivision, Phase 1. Water Works currently serves approximately 110 residential customers and Aqua expects eventually to serve a total of 121 customers in these two subdivisions.

On May 20, 2015, the Commission issued an Order Scheduling Hearing and Requiring Customer Notice, setting this matter for hearing on July 16, 2015; directing that a Notice to Customers be mailed with sufficient postage or hand delivered by Aqua to all affected customers no later than five business days after the date of the order; and requiring that Aqua submit to the Commission a Certificate of Service, properly signed and notarized, indicating that the notice had been sent to customers as directed.

On July 9, 2015, the Public Staff pre-filed the testimonies of Public Staff Accountant Laura D. Bradley and Public Staff Engineer Charles Junis.

On July 16, 2015, Aqua filed the Certificate of Service, stating that the customers had been provided notice as directed in the Commission's Order Scheduling Hearing and Requiring Customer Notice.

On July 16, 2015, the matter was called for hearing. The Public Staff made an oral motion that the Hearing Examiner bifurcate the proceeding by ruling: i) first, on the Application and Notification, leaving the request for rate increase open for 30 days after the closing of the transfer of the system from Water Works to Aqua in order for Aqua to complete necessary improvements to the system; and ii) second, on the rate increase for the 30 day period for completion of the improvements by Aqua. None of the parties objected to this motion.

In addition, Aqua made an oral motion that the Hearing Examiner waive the time period set forth in G.S. 62-78 afforded for parties to the proceeding to file exceptions to a recommended order, indicating that all parties to the proceeding agreed to waive their right to file exceptions. To this end, Aqua requested that the Hearing Examiner's Recommended Order approving the Application and the Notification be final and effective upon date of issuance.

Thereafter, the Hearing Examiner opened the public hearing, during which one public witness provided testimony. The public witness, Deborah Perotti is not a customer of Water Works, but testified on behalf of her son and daughter-in-law who are customers, and expressed general concern about rate increases.

Immediately following the public hearing, the matter was called for evidentiary hearing.

Aqua did not present a witness at the evidentiary hearing but indicated that Thomas J. Roberts and C. Ruffin Poole were in attendance and available for questions following the hearing.

The Public Staff moved that the Hearing Examiner excuse the appearance of its witness Laura D. Bradley and allow the introduction of her pre-filed testimony and exhibit into the record, as if presented orally, indicating that all of the parties had agreed to stipulate to Ms. Bradley's testimony and to waive their right to cross-examine her. This motion was granted. Public Staff witness Charles Junis presented his testimony.

On the basis of the Application, the Notification, the testimonies and the entire record in this proceeding, the Hearing Examiner makes the following:

FINDINGS OF FACT

1. Water Works owns the assets and holds a franchise to provide water utility service to residential customers in Timberlake Subdivision, in Alamance County, North Carolina.

2. The water system is permitted by the North Carolina Department of Environment and Natural Resources, Public Water Supply Section (PWSS) to serve 49 lots in the Timberlake, Phase 1 subdivision and 72 lots in Thornton Ridge subdivision (also referred to as Timberlake, Phase 2), for a total of up to 121 residential connections.

3. The Thornton Ridge subdivision is immediately adjacent and thereby contiguous to the Timberlake subdivision.

4. Water Works currently serves 110 customers.

5. Water Works and Aqua entered into an Assets Purchase Agreement, dated January 27, 2015, as amended by that First Amendment to Assets Purchase Agreement, dated February 26, 2015, pursuant to which Water Works has agreed to sell and Aqua has agreed to purchase the assets of Water Works for $40,000, and up to $4,000 of Water Works' attorney fees for representation in this transaction and this Commission proceeding.

6. The Public Staff has calculated Water Works original cost net investment to be $11,888 and has recommended a positive purchase price acquisition adjustment of $32,112, such that Aqua's cost net investment is $44,000.00, the full purchase price plus attorney's fees.

7. The Timberlake and Thornton Ridge customers will benefit from the approximately $20,000 in system improvements Aqua will make to the well house, hydropneumatic storage tank, valve bank renovations and replacing a missing well pump. Aqua's only business is providing water and wastewater utility service. Aqua has more than 160 employees in North Carolina and has a number of water systems in adjoining Orange and Chatham Counties. These customers will receive significantly improved water service reliability from the plant improvements Aqua will make and Aqua's extensive field service operations.

8. Aqua's statewide uniform rate customers will benefit as Aqua's original cost net investment, including Aqua's planned infrastructure improvements in this Timberlake and Thornton Ridge Water system will total approximately $64,000, or $582 per customer ($64,000 ÷ 110 residential equivalent units – REUs), which is only 37% of Aqua's $1,565 per REU uniform rate original cost net investment in Aqua's May 2, 2014, general rate case order in Docket No. W-218, Sub 363. The fact that Aqua's original cost net investment in Timberlake and Thornton Ridge is so much lower than Aqua's original cost net investment per customer for its statewide uniform rate customers, will provide downward pressure on the Aqua's uniform rates in Aqua's next general rate case, thereby benefiting Aqua's uniform rate customers.

9. The transaction is prudent, the result of arm's length bargaining, and the benefits accruing to both the customers on the Timberlake and Thornton Ridge water system and Aqua's

statewide uniform rate customers outweigh the costs of inclusion in rate base of the excess purchase price.

10. Although Water Works is providing adequate service, the Public Staff found that the system requires some maintenance, repair, and/or replacement to meet the requirements of the PWSS permits. Specifically, the Public Staff confirmed that: i) the pump and well seal at one of the well sites had been removed; ii) a gate valve was leaking from the 4,000-gallon hydropneumatic tank; and iii) many electrical components appeared to be rewired, potentially improperly.

11. Aqua has the technical, managerial, and financial capacity to own and operate the water system serving the Timberlake and Thornton Ridge subdivisions.

12. The Public Staff has recommended that Aqua be required to post a $20,000 bond for Timberlake and Thornton Ridge Subdivisions. Aqua currently has $11,800,000 of bonds posted with the Commission. Of this amount, $11,250,000 of bond surety is assigned to specific subdivisions and $550,000 of bond surety is unassigned.

13. To date, Water Works has not reduced its rates in accordance with the Commission’s Order Approving Tariff Revision and Requiring Refund in Docket No. W-1149, Sub 7.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence supporting these findings is found primarily in the Application, Notification and testimony of Public Staff witness Junis. These findings are jurisdictional, informational and are not contested.

Commission Rule R7-38 of the Rules and Regulations of the North Carolina Utilities Commission allows for the extension of water utility service into territory that is immediately adjacent to the service territory already occupied by the water utility system. The Hearing Examiner notes that the Thornton Ridge subdivision is immediately adjacent to the Timberlake Subdivision, which is occupied by the water utility system. Therefore, the Hearing Examiner finds that the contiguous extension of water utility service into the Thornton Ridge subdivision meets the Commission’s criteria for such extension and recognizes such extension.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-11

The evidence supporting these findings is found primarily in the testimonies of Public Staff witnesses Bradley and Junis.

The Commission has heretofore allowed a positive purchase price acquisition adjustment when: 1) the benefit to customers outweighs the cost of inclusion in rate base of the excess purchase price; 2) the transaction is prudent; 3) the transaction is the result of arm's length bargaining. (See Order Approving Transfer, Acquisition Adjustment, and Maintaining Current

Rates, Docket No. W-274, Sub 122, April 30,1997 (the Hardscrabble Order), Finding of Fact No. 14.)

The Public Staff engineer Junis testified regarding the deficiencies in Water Works' water utility system. Specifically, the Public Staff noted that: i) the pump and well seal at one of the well sites had been removed; ii) a gate valve was leaking from the 4,000-gallon hydropneumatic tank; and iii) many electrical components appeared to be rewired, potentially improperly.

Ms. Bradley testified the Timberlake and Thornton Ridge customers will benefit from the approximately $20,000 in system improvements Aqua will make to the well house, hydropneumatic storage tank, valve bank renovations and replacing a missing well pump. Aqua's only business is providing water and wastewater utility service. Aqua has more than 160 employees in North Carolina and has a number of water systems in adjoining Orange and Chatham Counties. These customers will receive significantly improved water service reliability from the plant improvements Aqua will make and Aqua's extensive field service operations.

Ms. Bradley testified the purchase price is prudent, the result of arm's length bargaining, and the benefits accruing to both the customers on the Timberlake and Thornton Ridge water system and Aqua's statewide uniform rate customers outweigh the costs of inclusion in rate base of the excess purchase price.

Ms. Bradley further testified that Aqua's statewide uniform rate customers will benefit as Aqua's original cost net investment including Aqua's planned infrastructure improvements in this Timberlake and Thornton Ridge Water system will total approximately $64,000, being $582 per customer ($64,000 ÷ 110 residential equivalent units – REUs), which is only 37% of Aqua's $1,565 per REU uniform rate original cost net investment in Aqua's May 2, 2014, general rate case order in Docket No. W-218, Sub 363. The fact that Aqua's original cost net investment in Timberlake and Thornton Ridge is so much lower than Aqua's original cost net investment per customer for its statewide uniform rate customers, will provide downward pressure on the Aqua's uniform rates in Aqua's next general rate case, thereby benefiting Aqua's uniform rate customers.

Therefore, the Hearing Examiner finds and concludes that the benefit to customers, both existing Water Works customers and existing Aqua customers, outweighs the cost of inclusion in rate base of the excess purchase price. Finally, as testified by the Public Staff witness Bradley, the transaction is prudent and was the result of arm's length negotiation. Based upon the foregoing, and the specific facts and circumstances of this case, the Hearing Examiner concludes that the recommended purchase price acquisition adjustment of $32,112 is allowed, such that Aqua's cost net investment is $44,000.00.

As the Commission noted in its Hardscrabble Order, "the Commission has articulated a position of encouraging the orderly transfer of water systems from developers and small owners to reputable water utilities. . . ." Hardscrabble Order, p. 11. The Hearing Examiner notes that Aqua is a reputable water utility, with the technical, managerial, and financial capacity to own and operate the water system, and that the decision to allow the purchase price acquisition adjustment, based upon the facts and circumstances presented, promotes and serves this position and is in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 12

The evidence supporting this finding is found in the testimony of Public Staff witness Junis.

The Public Staff recommended that Aqua be required to post a $10,000 bond for the water system serving the Timberlake subdivision and an additional $10,000 bond for the contiguous extension of water utility service into the Thornton Ridge subdivision. The Public Staff testified that Aqua currently has $11,800,000 of bond posted with the Commission, which includes enough unassigned funds to provide the bonds recommended in this docket. The Hearing Examiner accepts the recommendation of the Public Staff and approves Aqua's posting of a $10,000 bond for the Timberlake subdivision and a $10,000 bond for the Thornton Ridge subdivision.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 13

On February 13, 2015, the Commission issued an Order Approving Tariff Revision and Requiring Refund in Docket No. W-1149, Sub 7. Under this Order, Water Works' rates were reduced by 4% to reflect the repeal of gross receipts tax, and Water Works was required to issue a bill credit to its customers equal to any revenues billed at the old rates on or after July 1, 2014, times 4% for water operations. The Order required that Water Works submit a verification that the rates had been reduced and the refund made not later than thirty days from the date of the Order. The Public Staff witness Bradley testified that no such verification has been filed by Water Works and recommended that Water Works be directed to file the verification, indicating that the refund has been made, or that Aqua be directed to fund the refund through a credit reduction to the purchase price.

Consistent with the recommendation of the Public Staff, the Hearing Examiner concludes that amount to be refunded, per the Commission's Order Approving Tariff Revision and Requiring Refund in Docket No. W-1149, Sub 7, be provided to Aqua by Water Works prior to the time of the closing of the transfer of the assets from Water Works to Aqua, through a credit reduction of the purchase price. Further, the Hearing Examiner directs Aqua to make the required refunds during the first billing cycle following the transfer to Aqua.

Based upon the Application, Notification, and testimony and exhibit contained in the record, the Hearing Examiner concludes that the transfer of the franchise and assets from Water Works to Aqua is in the public interest and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That $20,000 of the $550,000 unassigned bond surety shall be assigned to Timberlake and Thornton Ridge Subdivisions. The remaining unassigned bond surety shall be $530,000.

2. That the application for the transfer of the water system and certificate of public convenience and necessity to provide water utility service in Timberlake Subdivision in Alamance County from Water Works to Aqua, is hereby approved.

3. That the contiguous extension of water utility service from the Timberlake service area into the Thornton Ridge Subdivision in Alamance County, North Carolina, is recognized as meeting the Commission's criteria for the extension.

4. That Appendix A attached hereto shall constitute the Certificate of Public Convenience and Necessity for Timberlake and Thornton Ridge Subdivisions.

5. That the $10,000 bond posted by Water Works is hereby released. That SunTrust Bank is hereby authorized to release the $10,000 held in Account Number 10000 3 6 9080 3 for the benefit of the North Carolina Utilities Commission to Water Works of Alamance County, Inc.

6. That a connection fee of $400 per REU for water service is approved for Timberlake and Thornton Ridge Subdivisions.

7. That the positive acquisition adjustment of $32,112 is approved. That Aqua shall, in future rate case proceedings, be allowed rate base treatment of its $40,000 purchase price plus up to $4,000 of Water Works' legal fees payable to Charlotte Mitchell.

8. That the Notice to Customers attached hereto as Appendix B shall be mailed with sufficient postage or hand delivered to all customers in Timberlake and Thornton Ridge within ten days of the date of this Order.

9. That Charlotte Mitchell shall submit to Aqua her final invoice and any prior invoices for legal services, which Aqua shall pay to Charlotte Mitchell up to $4,000. Aqua shall retain these invoices for further audit by the Public Staff, and this payment shall be included in Aqua's rate base.

10. That Aqua shall notify the Commission within five business days after the closing of the transfer of assets.

11. That Aqua shall refund by bill credit to each of the customers the Commission ordered 4% refund in the Docket No. W-1149, Sub 7, order dated February 13, 2015. The amount Aqua refunds shall be a credit to each customer on Aqua's first customer billing. Water Works shall provide Aqua prior to the transfer closing the amount of refund owed to each customer including supporting documentation. The amount of refund shall be deducted from the purchase price paid at closing, and the refund amount shall be included in Aqua's rate base.

12. That the interim rates approved for Aqua are Water Works' Commission approved current rates. The rate increase portion of this proceeding shall be held open for a period of 30 days after the transfer closing. On or before the 30th day, Aqua shall submit to the Public Staff the documentation on Aqua's completed system capital improvements. The Public Staff shall then recalculate the Public Staff's recommended rates including depreciation expense and return on rate base for the completed system capital improvements.

13. The Public Staff shall, within 20 days after receiving Aqua's completed system capital improvement documentation, file a proposed order for the rate increase portion of this proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the ___10th___ day of _____August___, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

DOCKET NO. W-218, SUB 408

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

AQUA NORTH CAROLINA, INC.

is granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

to provide water utility service

in

TIMBERLAKE SUBDIVISION
THORNTON RIDGE SUBDIVISION

Alamance County, North Carolina

subject to any orders, rules, regulations,
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the _10th___day of ___August__, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B

NOTICE TO CUSTOMERS
DOCKET NO. W-218, SUB 408
DOCKET NO. W-1149, SUBS 8 AND 9

Notice is given that the North Carolina Utilities Commission (Commission) has approved the transfer of the water utility system serving Timberlake and Thornton Ridge Subdivisions in Alamance County from Water Works of Alamance County, Inc. (Water Works), to Aqua North Carolina, Inc. (Aqua).

The Commission previously approved rates for Water Works are approved as temporary rates for Aqua. These temporary rates are:

Monthly Metered Water Utility Service

Base charge, zero usage	$9.60
Usage charge, per 1,000 gallons	$2.88

The Commission has held open Aqua's applied for rate increase for thirty days subsequent to the closing of the transfer of the water utility system assets from Water Works to Aqua in order for Aqua to make water system improvements including renovations to the well house, hydropneumatic water storage tank, valve bank, electrical and replacing a missing pump. These Aqua system improvements will improve the water utility system's reliability. After Aqua provides the Public Staff complete documentation on the cost of the improvements, and the Public Staff completes its audit of these improvement costs, the Public Staff will recommend to the Commission increased rates for Aqua.

The Commission will evaluate all the evidence in this proceeding including the Public Staff's recommendation on the water rates, and then issue a further order for Aqua's water rates.

This the _10th ___ day of ___August_____, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

DOCKET NO. W-1305, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Pluris Hampstead, LLC, 2100 McKinney Avenue, Suite 1550, Dallas, Texas, 75201, for a Certificate of Public Convenience and Necessity and Approval of Rates for the Blake Farms, Olde Pointe Village, Topsail High School, Topsail Middle School, Topsail Elementary School, and Hardison Development in Pender County, North Carolina	ORDER GRANTING FRANCHISE AND APPROVING RATES

BY THE COMMISSION: On June 12, 2014, Pluris Hampstead, LLC (Pluris), filed an application for a certificate of public convenience and necessity and for approval of rates, to provide wastewater utility service to Blake Farms, Olde Point Village, Topsail High School, Topsail Middle School, Topsail Elementary School, and Hardison Development in Pender County, North Carolina (Application). Pluris made additional filings on January 21, 2015, July 15, 2015, October 9, 2015, and October 27, 2015, consisting of wastewater system permits, a contract with Pender County Schools, a $200,000 bond, service area maps and modified applied for service rate documentation.

The Public Staff presented this matter at the Commission's Regular Staff Conference on November 2, 2015

Based upon the verified notification, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. Pluris does not presently hold any water or wastewater franchises in North Carolina. Its affiliate, Pluris LLC, has the franchise for the North Topsail wastewater system service area.

2. Pluris has executed a wastewater service agreement dated June 6, 2014, with Pender Farm Development, LLC, to provide wastewater utility service to Blake Farms for approximately 280 single-family residences.

3. Pluris has executed a wastewater service agreement dated June 6, 2014, with Pender Farm Commercial, LLC, for a commercial development at Blake Farm including 288 multi-family apartment residences.

4. Pluris has executed a wastewater service agreement dated June 6, 2014, with OPV Development, LLC, for Olde Point Village for 96 single family residences.

5. Pluris has executed a wastewater service agreement dated June 10, 2014, with Hampstead Partners, LLC, for the Hardison Development with single family residences and commercial businesses for a combined maximum of 60,000 gpd to 90,000 gpd.

6. Pluris has executed an Agreement for Sanitary Sewer Service with the Pender County Board of Education (Board) dated October 6, 2014, to provide wastewater utility service not to exceed an aggregate of 13,500 gpd for Topsail High School, Topsail Middle School and Topsail Elementary School. The Board will construct at Board's expense the collection system and the interconnection to the Pluris' force main. The Board has agreed to pay a connection fee of $120,000.

7. In each of the contracts for Blake Farms, Olde Point Village, and Hardison Development, the developer at developer's cost will install the wastewater collection system and interconnect with Pluris' force main. The agreed upon connection fee for a three bedroom home is $3,200. The connection fee would increase by $1,067 for each bedroom in a single family residence beyond three. The connection fee for non-residential customers is $3,200 for a single family equivalent (SFE) design flow of 360 gallons per day (gpd).

8. The service areas for Blake Farms, Blake Farm Multi-Family Apartments, Olde Point Village, and Hardison Development are shown on Application Exhibit 10. The service areas for the three Pender County Schools were filed with the Commission on October 27, 2015.

9. The North Carolina Department of Environment and Natural Resources Division of Water Resources (DWR) issued to Pluris Permit No. WQ0037287 dated April 29, 2015, for the construction and operation of a 250,000 gpd membrane bioreactor (MBR) wastewater treatment plant (WWTP) and two high rate effluent infiltration basins for 50,000 gpd.

10. DWR previously issued to Pluris Permit No. WQ0037324 dated August 26, 2014, for the construction of 16,025 linear feet of 10-inch force main and 20,200 linear feet of 12-inch force main from the WWTP site near Hampstead running north on the west side of U.S. Highway 17.

11. On October 9, 2015, the North Carolina Department of Environmental Quality (formerly NC DENR) issued to Pluris National Pollutant Discharge Elimination System (NPDES) Permit No. NC 008924 to discharge up to 250,000 gpd of wastewater effluent from Pluris' MBR WWTP into an unnamed tributary to Island Creek, in the Cape Fear River Basin.

12. DWR issued Permit No. WQ0037824 dated June 12, 2015, for the construction of the Olde Point Village collection system. DWR issued Permit No. WQ0031241 Modification dated June 23, 2015, for the construction of the Pender County Topsail Three-School Complex collection system. DWR issued Permit No. WQ0037863 dated June 25, 2015, for the construction of the Hardison Development collection system. DWR issued Permit No. WQ00037905 dated July 13, 2015, for the construction of the Blake Farms collection system.

13. The Public Staff recommended that Pluris post a $100,000 bond for these four service areas. Pluris has posted a $200,000 bond in a form acceptable to the Commission.

14. Pluris has applied for the following rates:

Residential Monthly Flat Rate	$63.95
Commercial (Metered) Rate	
Monthly Base Facilities Charge	$25.24
Commodity Charge, Per 1,000 gallons	$ 9.68
Connection Charge-Residential	
For 3 bedrooms or less	$3,200 per SFE
Each additional bedroom beyond three per residence	$1,067
Connection Charge – Commercial	
SFE equals 360 gpd DWR design flow	$3,200 per SFE

15. Pluris has filed all required exhibits.

16. Pluris has the technical, managerial, operational and financial capacity to provide wastewater utility service to these franchise locations.

17. The Public Staff has recommended approval of the franchise and applied for service rates and connection fees as set forth on Exhibit B of the application, and that the Commission accept the $200,000 bond filed by Pluris and assign $100,000 of the bond to this franchise.

CONCLUSIONS

Based upon the foregoing and the recommendations of the Public Staff, the Commission accepts the $200,000 bond posted by Pluris and concludes that $100,000 of the bond shall be assigned to this franchise serving Blake Farms, Olde Pointe Village, Topsail High School, Topsail Middle School, Topsail Elementary School, and Hardison Development (the remaining $100,000 bond surety will be assigned to specific service areas in the future); that the wastewater utility franchise requested by Pluris in these areas should be granted; and the Schedule of Rates set forth on Appendix B of this Order should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the $200,000 corporate surety bond filed by Pluris Hampstead, LLC, is hereby accepted and approved.

2. That $100,000 of the $200,000 bond shall be assigned to Blake Farms, Olde Pointe Village, Topsail High School, Topsail Middle School, Topsail Elementary School, and Hardison Development. The remaining unassigned bond surety shall be $100,000.

3. That Pluris Hampstead, LLC is granted a certificate of public convenience and necessity to provide sewer utility service for Blake Farms, Olde Pointe Village, Topsail High

School, Topsail Middle School, Topsail Elementary School, and Hardison Development in Pender County, North Carolina.

4. That Appendix A constitutes the Certificate of Public Convenience and Necessity

5. That the Schedule of Rates attached hereto as Appendix B is approved.

ISSUED BY ORDER OF THE COMMISSION.
This the __5th____ day of __November_____, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

Commissioner Susan W. Rabon did not participate.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

DOCKET NO. W-1305, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

PLURIS HAMPSTEAD, LLC

is granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

to provide sewer utility service

in

BLAKE FARMS, OLDE POINTE VILLAGE, TOPSAIL HIGH SCHOOL, TOPSAIL MIDDLE SCHOOL, TOPSAIL ELEMENTARY SCHOOL, AND HARDISON DEVELOPMENT

Pender County, North Carolina,

subject to any orders, rules, regulations,
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the __5th____ day of ___November_____, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

APPENDIX B
PAGE 1 OF 3

SCHEDULE OF RATES

for

PLURIS HAMPSTEAD, LLC,

for providing sewer utility service in

BLAKE FARMS, OLDE POINTE VILLAGE, TOPSAIL HIGH SCHOOL, TOPSAIL MIDDLE SCHOOL, TOPSAIL ELEMENTARY SCHOOL, AND HARDISON DEVELOPMENT

Pender County, North Carolina

Monthly Residential Flat Rate:	$63.95 per unit
Monthly Commercial Metered Rates:	
Base charge, zero usage	$25.24 minimum
Usage charge per 1,000 gallons	$ 9.68

Customers who ask to be reconnected at the same service location within nine months of disconnection, will be charged the entire flat rate or base monthly charge for the periods they were disconnected.

Reconnection Charges:

If sewer service cut off by utility for good cause Actual cost

(Customers shall be given a written estimate of the actual costs prior to disconnection. An actual invoice of the costs shall be given to the customer following disconnection.)

APPENDIX B
PAGE 2 OF 3

Connection Fee:

Residential: $3,200 per SFE

Each additional bedroom beyond

three per residence	$1,067
Commercial:	$3,200 per SFE

A single family equivalent (SFE) for a detached single family residence is three or less bedrooms.

A SFE for a commercial connection is determined by taking the design flow capacity for each non-residential commercial customer, as set forth in Administrative Code 15A NCAC 2 T .0114, and dividing the design flow by 360.

Road Bore Charge:

The road bore charge shall be the actual costs of labor and materials for the road boring. This charge shall be in addition to the connection fee. The customer may, choose to have a licensed contractor perform the road bore at the customer's sole expense, provided that the road bore and all related work shall be in accordance with Pluris's standards.

The above connection fees, and Road Bore Charge do not apply to future connections for which prepaid connection fees have been received prior to the date of this Order.

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Return Check Charge:	$25.00
Billing Frequency:	
Flat Rate Residential Customers	Shall be monthly for service in advance
Metered Commerical Customers	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1305, Sub 0, on this the __5th___ day of ___November__, 2015.

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Approval of Semiannual Adjustments to Water and Sewer System Improvement Charges pursuant to G.S. 62-133.12	)))))	ORDER APPROVING WATER AND SEWER SYSTEM IMPROVEMENT CHARGES ON A PROVISIONAL BASIS AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On October 30, 2015, Aqua North Carolina, Inc. (Aqua), filed an application requesting authority to increase its Water System Improvement Charges (WSIC) and Sewer System Improvement Charges (SSIC) effective January 1, 2016, pursuant to Commission Rules R7-39 and R10-26 (Application).

On December 2, 2015, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's December 14, 2015, Regular Staff Conference.

On December 14, 2015, the Public Staff presented this matter to the Commission at the Regular Staff Conference.

On the basis of the verified Application, the records of the Commission, and the comments and recommendations of the Public Staff, the Commission makes the following

FINDINGS OF FACT

1. Aqua is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. Aqua is a franchised public utility providing water and/or sewer utility service to customers in North Carolina.

2. In its Order dated May 2, 2014, in Aqua's last general rate case proceeding, Docket No. W-218, Sub 363 (Sub 363 Rate Case), the Commission approved Aqua's request to utilize a WSIC and SSIC mechanism pursuant to G.S. 62-133.12, concluding that the rate adjustment mechanisms are in the public interest, and establishing WSIC and SSIC procedures for Aqua.

3. The implementation of the WSIC and SSIC for Aqua was first approved on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1st and July 1st based upon reasonable and prudently incurred investment in eligible system improvements completed and placed in service prior to the filing of the request.

4. Aqua's proposed increases to the WSIC and SSIC previously approved by the Commission on June 23, 2015, are as follows:

Rate Division	Previously Approved WSIC & SSIC Percentage	Additional WSIC & SSIC Percentage	Cumulative WSIC & SSIC Percentage
Uniform water	0.44%	1.34%	1.78%
Uniform sewer	0.98%	0.98%	1.96%
Fairways/Beau Rivage water	0.00%	0.04%	0.04%
Fairways/Beau Rivage sewer	0.69%	0.58%	1.27%
Brookwood/LaGrange water	1.06%	0.94%	2.00%

5. Pursuant to G.S. 62-133.12(g), the cumulative WSIC and SSIC percentages are capped at 5% of the total annual service revenues approved by the Commission in the Sub 363 Rate Case. The cumulative WSIC and SSIC revenue requirements under Aqua's proposal do not exceed the caps.

6. The cumulative WSIC and SSIC revenue requirements after Aqua's proposed increases are as follows:

Rate Division	Previously Approved WSIC/SSIC Revenue Requirement	Additional WSIC/SSIC Revenue Requirement	Cumulative WSIC/SSIC Revenue Requirement
Uniform water	$138,566	$433,617	$572,183
Uniform sewer	112,568	117,791	230,359
Fairways/Beau Rivage water	11	324	335
Fairways/Beau Rivage sewer	8,014	7,131	15,145
Brookwood/LaGrange water	52,805	44,676	97,481

7. Aqua's additional WSIC/SSIC revenue requirement listed above is comprised of two amounts, the calculated WSIC/SSIC revenue requirement for this current review period, less the adjustment to update the annual WSIC/SSIC revenue requirement awarded to Aqua on December 22, 2014, effective January 1, 2015, from Aqua's first WSIC/SSIC surcharge application.

8. Aqua is proposing the above increases in the WSIC and SSIC in order to recover the incremental depreciation and capital costs associated with the following WSIC and SSIC projects completed and placed in service from April 1, 2015 through September 30, 2015:

Replace valves	$ 101,233
Replace services	462,385
Treatment for primary drinking water standards	145,504
Treatment for secondary drinking water standards	3,315,923
Total WSIC plant additions	$4,025,045

Replace lift station and treatment plant pumps	$ 187,969
Replace blowers and motors	31,780
Inflow & infiltration improvements	1,183,415
Replace mixer	7,186
Total SSIC plant additions	$ 1,410,350

9. Under G.S. 62-133.12(c), eligible water system improvements include equipment and infrastructure installed at the direction of the Commission to comply with secondary drinking water standards. During the six months ended September 30, 2015, Aqua installed 10 cartridge filtration projects at the Monticello, Belews Landing, Spencer Road Acres, Clearview Acres, High Meadows, Hillsboro, Kensington Manor, Kimmon Place, Rowland Pond, and Ogburn Farms systems for a total cost of $58,025. During the six months ended September 30, 2015, Aqua installed eight manganese greensand filtration projects at Ole Mill Stream, Stone Creek, Meadow Ridge, Westmoor, Lake Rand, Stonebridge, Devon, and Coachman's Trail systems for a total cost of $3,257,898. The Commission authorized the implementation of these filtration projects in its Order Approving Secondary Water Quality Improvement Projects issued on December 22, 2014 and May 21, 2015, in this docket.

10. As stated by the Commission in its Order adopting Rules R7-39 and R10-26, issued on June 6, 2014, in Docket No. W-100, Sub 54, the Public Staff is to review all infrastructure improvements proposed for recovery for eligibility and reasonableness prior to making its recommendation to the Commission on WSIC or SSIC rate adjustments. Furthermore, any WSIC or SSIC rate adjustments will be allowed to become effective, but not unconditionally approved. These adjustments shall be further examined for a determination of their justness and reasonableness in the Company's next general rate case. At that time, the adjustments may be rescinded retroactively if the Commission determines that the adjustments were not prudent, just and/or reasonable.

11. Based on the Public Staff's investigation to date, the WSIC and SSIC projects included in Aqua's request are eligible water and sewer system improvements as defined in G.S. 62-133.12(b), (c), and (d).

12. Based on the Public Staff's investigation to date, the Public Staff recommended that the cumulative WSIC and SSIC percentages proposed by Aqua be implemented effective for service rendered on or after January 1, 2016, subject to true-up. The Public Staff will continue to review the justness, prudency, and reasonableness of these improvements during its review of Aqua's future WSIC and SSIC filings and in Aqua's next general rate case proceeding.

CONCLUSIONS

Based upon the foregoing, the Commission concludes that Aqua should be allowed to implement its proposed increases in the WSIC and SSIC percentages effective for service rendered on and after January 1, 2016. These WSIC or SSIC rate adjustments, while allowed to become effective, are not unconditionally approved, and will be subject to further examination for justness and reasonableness in the WSIC and SSIC annual review and reconciliation and Aqua's next general rate case proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That Aqua is authorized to implement the proposed Water and Sewer System Improvement Charges set forth in the attached Appendix A-3 to Aqua's Schedule of Rates effective for service rendered on and after January 1, 2016, subject to true-up. The rates contained therein are provisional and subject to review in Aqua's next general rate case proceeding.

2. That the attached Appendix A-3 is approved and is deemed filed with the Commission pursuant to G.S. 62-138.

3. That Aqua shall mail to each of its customers with the next regularly scheduled customer billing the Commission approved customer notice.[1]

ISSUED BY ORDER OF THE COMMISSION.
This the _17th_ day of December, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Commissioner Don M. Bailey did not participate in this decision.

APPENDIX A-3

AQUA NORTH CAROLINA, INC.
WATER AND SEWER SYSTEM IMPROVEMENT CHARGES

WATER SYSTEM IMPROVEMENT CHARGE

All Aqua NC water systems except as noted below	1.78% 1/
Water systems in Brookwood and LaGrange service areas	2.00% 1/
Water systems in Fairways and Beau Rivage service areas	0.04% 1/
Glennburn, Knollwood, and Wimbledon systems in Gaston County	None 2/
Timberlake and Thorton Ridge system in Alamance County	None 3/

[1] Three separate customer notices are attached hereto as Attachments A, B, and C, respectively. The separate customer notices are intended to minimize customer confusion. Aqua shall mail the appropriate customer notice to each of its customers with the next regular customer billing.

SEWER SYSTEM IMPROVEMENT CHARGE

All Aqua NC sewer systems except as noted below	1.96% 4/
Sewer systems in Fairways and Beau Rivage service areas	1.27% 4/

1/ The Water System Improvement Charge will be applied to the total water utility bill of each customer under the Company's applicable rates and charges.

2/ These water systems, which were acquired from Wayne M. Honeycutt in Docket No. W-218, Sub 385, are not included under Aqua's uniform rates and improvements made in these systems are not eligible for Water System Improvement Charge recovery.

3/ The Timberlake and Thorton Ridge water system, which was acquired from Water Works of Alamance County, Inc., in Docket No. W-218, Sub 408, is not included under Aqua's uniform rates and improvements made in this system are not eligible for Water System Improvement Charge recovery.

4/ The Sewer System Improvement Charge will be applied to the total sewer utility bill of each customer under the Company's applicable rates and charges.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 363A on this the 17th day of December, 2015.

ATTACHMENT A
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	NOTICE TO CUSTOMERS IN
202 MacKenan Court, Cary, North Carolina	)	BROOKWOOD / LAGRANGE
27511, for Approval of Semiannual	)	SERVICE AREAS
Adjustments to Water and Sewer System	)	
Improvement Charges Pursuant to	)	
G.S. 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated December 17, 2015, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to increase the Water System Improvement Charge (WSIC) effective for service rendered on and after January 1, 2016, in Aqua's Brookwood/LaGrange service areas in Cumberland and Hoke Counties, in North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC/SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in Aqua's last general rate case proceeding. WSIC and SSIC charges for Aqua were first approved by the Commission on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1 and July 1. On October 30, 2015, Aqua filed for its second semiannual adjustment to the WSIC and SSIC charges to become effective January 1, 2016.

ATTACHMENT A
PAGE 2 OF 3

The Public Staff carefully reviewed Aqua's stated WSIC and SSIC improvements, including a review of invoices, materials lists, work orders, employee time sheets, and other accounting records. On December 3, 2015, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations (Notice and Recommendations) at the Commission's December 14, 2015, Regular Staff Conference.

Aqua made WSIC eligible infrastructure improvements in the Brookwood/LaGrange service area replacing water service lines, installing a radium removal filter at Stoney Point, and replacing valves at Arran Hills to comply with primary drinking water standards.

Based on the application filed by Aqua and the Public Staff's Notice and Recommendations, the Commission has approved the following increase in the WSIC charge for the Brookwood and LaGrange service areas, effective for service rendered on and after January 1, 2016:

	Previously Approved WSIC & SSIC Percentage	Additional WSIC & SSIC Percentage	Cumulative WSIC & SSIC Percentage
WSIC	1.06%	0.94%	2.00%

The WSIC percentage of 2.00% will be applied to the water utility bill of each customer under Aqua's applicable service rates and charges.

The cumulative 2.00% WSIC percentage results in a cumulative $0.61 increase to the monthly average residential bill for a customer using the average of 5,817 gallons per month.

Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed October 30, 2015, the December 3, 2015 Public Staff Notice, and the December 17, 2015 Commission Order in Docket No. W-218, Sub 363A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e., for Docket Number key: W-218 Sub 363A).

ATTACHMENT A
PAGE 3 OF 3

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the _17th__ day of December, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

ATTACHMENT B
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	NOTICE TO CUSTOMERS IN
27511, for Approval of Semiannual	)	FAIRWAYS AND BEAU RIVAGE
Adjustments to Water and Sewer System	)	SERVICE AREAS
Improvement Charges Pursuant to	)	
G.S. 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated December 17, 2015, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to increase the Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC) effective for service rendered on and after January 1, 2016, in Aqua's Fairways and Beau Rivage service areas in New Hanover County, North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC/SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in Aqua's last general rate case proceeding. WSIC and SSIC charges for Aqua were first approved by the Commission on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1 and July 1. On October 30, 2015, Aqua filed for its second semiannual adjustment to the WSIC and SSIC charges to become effective January 1, 2016.

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The Public Staff carefully reviewed Aqua's stated WSIC and SSIC improvements, including a review of invoices, materials lists, work orders, employee time sheets, and other accounting records. On December 3, 2015, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's December 14, 2015 Regular Staff Conference (Notice).

Aqua made WSIC and SSIC eligible infrastructure improvements in the Fairways and Beau Rivage service areas replacing water services, upgrading wastewater treatment plant pumps, blowers and motors, and improvements to reduce and eliminate the inflow and infiltration of rainwater into a portion of the sewer collection system.

Based on the application filed by Aqua and the Public Staff's Notice and recommendations, the Commission has approved the following increases in the WSIC and SSIC charges for the Fairways and Beau Rivage service areas, effective for service rendered on and after January 1, 2016:

	Previously Approved WSIC & SSIC Percentage	Additional WSIC & SSIC Percentage	Cumulative WSIC & SSIC Percentage
WSIC	0.00%	0.04%	0.04%
SSIC	0.69%	0.58%	1.27%

The WSIC percentage of 0.04% will be applied to the water utility bill of each customer, and the SSIC percentage of 1.27% will be applied to the sewer utility bill of each customer, under Aqua's applicable service rates and charges.

The 0.04% WSIC percentage results in a cumulative $0.01 increase to the monthly average residential bill for a customer using the average of 7,655 gallons per month.

The cumulative SSIC percentage of 1.27% will be applied to the sewer utility bill of each customer under Aqua's applicable service rates and charges. The cumulative 1.27% SSIC percentage results in a cumulative $0.46 increase to the monthly residential customer flat rate sewer bill.

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Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed October 30, 2015, the December 3, 2015 Public Staff Notice, and the December 17, 2015 Commission Order in Docket No. W-218, Sub 363A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e., for Docket Number key: W-218 Sub 363A).

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the _17th_ day of December, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

ATTACHMENT C
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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Approval of Semiannual Adjustments to Water and Sewer System Improvement Charges Pursuant to G.S. 62-133.12	))))))	NOTICE TO CUSTOMERS IN AQUA NORTH CAROLINA SERVICE AREAS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated December 17, 2015, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to increase the Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC) effective for service rendered on and after January 1, 2016, in its service areas in North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC/SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in Aqua's last general rate case proceeding. WSIC and SSIC for Aqua were first approved by the Commission on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1 and July 1. On October 30, 2015, Aqua filed for its second semiannual adjustment to the WSIC and SSIC charges to become effective January 1, 2016.

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The Public Staff carefully reviewed Aqua's stated WSIC and SSIC improvements, including a review of invoices, materials lists, work orders, employee time sheets, and other accounting records. On December 3, 2015, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's December 14, 2015 Regular Staff Conference (Notice).

Aqua made WSIC eligible infrastructure improvements replacing service lines, installing filters to comply with primary drinking water standards, and installing filters for the treatment of iron and manganese which have secondary drinking water standards.

Aqua made SSIC eligible infrastructure improvements upgrading pump stations, upgrading wastewater treatment plant pumps, blowers and motors, and improvements to reduce and eliminate the inflow and infiltration of rainwater into sewer collection systems.

Based on the application filed by Aqua and the Public Staff's Notice and recommendations, the Commission has approved the following increases in the WSIC and SSIC charges, effective for service rendered on and after January 1, 2016:

	Previously Approved WSIC & SSIC Percentage	Additional WSIC & SSIC Percentage	Cumulative WSIC & SSIC Percentage
WSIC	0.44%	1.34%	1.78%
SSIC	0.98%	0.98%	1.96%

The WSIC percentage of 1.78% will be applied to the water utility bill of each customer, and the SSIC percentage of 1.96% will be applied to the sewer utility bill of each customer, under Aqua's applicable service rates and charges.

The cumulative 1.78% WSIC percentage results in a cumulative $0.82 increase to the monthly average residential bill for a customer using the average of 5,170 gallons per month. The cumulative 1.78% WSIC percentage also will apply to the monthly bills for the customers on water systems where Aqua purchases bulk water.

The cumulative 1.96% SSIC percentage results in a cumulative $1.28 increase to the monthly residential flat rate sewer bill. The cumulative 1.96% SSIC percentage will also apply to the monthly metered bills for customers on sewer systems where Aqua purchases bulk sewer treatment.

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Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed October 30, 2015, the December 3, 2015 Public Staff Notice, and the December 17, 2015 Commission Order in Docket No. W-218, Sub 363A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e., for Docket Number key: W-218 Sub 363A).

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the _17th_ day of December, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. W-354, SUB 344

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc. of	)	
North Carolina, 2335 Sanders Road,	)	ORDER APPROVING STIPULATIONS,
Northbrook, Illinois 60062, for Authority to	)	GRANTING PARTIAL RATE
Adjust and Increase Rates for Water and Sewer	)	INCREASE, AND REQUIRING
Utility Service in All of its Service Areas in	)	CUSTOMER NOTICE
North Carolina		

HEARD: Tuesday, June 23, 2015, at 7:00 p.m., in the Onslow County Courthouse, Summersill Building, Courtroom #5, 109 Old Bridge Street, Jacksonville, North Carolina

Wednesday, June 24, 2015, at 7:00 p.m., in the Currituck County Courthouse, Courtroom C, 2801 Caratoke Highway, Currituck, North Carolina

Wednesday, July 8, 2015, at 7:00 p.m., in the Mecklenburg County Courthouse, Courtroom 5310, 832 East Fourth Street, Charlotte, North Carolina

Wednesday, July 22, 2015, at 7:00 p.m., in the Watauga County Courthouse, 842 W. King Street, Boone, North Carolina

Thursday, July 23, 2015, at 7:00 p.m., in the Buncombe County Courthouse, Courtroom 1A, 60 Court Plaza, Asheville, North Carolina

Tuesday, July 7, 2015, at 7:00 p.m.; Monday, October 5, 2015, at 2:00 p.m.; and Tuesday, October 20, 2015, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; and Commissioners Bryan E. Beatty, Susan W. Rabon, ToNola D. Brown-Bland, Don M. Bailey, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

For Carolina Water Service, Inc. of North Carolina:

Jo Anne Sanford, Sanford Law Office, PLLC, P.O. Box 28085, Raleigh, North Carolina 27611-8085

Robert H. Bennink, Jr., Bennink Law Office, 130 Murphy Drive, Cary, North Carolina 27513

Charlotte A. Mitchell, Law Office of Charlotte Mitchell, P.O. Box 26212, Raleigh, North Carolina 27611

For the Using and Consuming Public:

Gina C. Holt and William E. Grantmyre, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For Corolla Light Community Association, Inc.:

Dwight W. Allen, Brady W. Allen, and Britton H. Allen, The Allen Law Offices, PLLC, 1514 Glenwood Ave., Suite 200, Raleigh, North Carolina 27608

BY THE COMMISSION: On February 26, 2015, Carolina Water Service, Inc. of North Carolina (CWSNC or Company) filed a letter notifying the North Carolina Utilities Commission (Commission or NCUC) of its intent to file a general rate case as required by Commission Rule R1-17(a). On March 31, 2015, CWSNC filed an application for a general rate increase (the Application) seeking authority: (1) to increase and adjust its rates for water and sewer utility service in all of its service areas in North Carolina; (2) to pass-through any increases in purchased bulk water rates, subject to sufficient proof by CWSNC of the increase, as well as any increased costs of wastewater treatment performed by third parties and billed to CWSNC; and (3) to increase certain other charges.

On April 10 and 21, 2015, CWSNC filed supplements to its NCUC Form W-1, Item 10 and Items 7, 9, and 16, respectively.

By Order issued April 30, 2015, the Commission declared the matter to be a general rate case pursuant to G.S. 62-137 and suspended the proposed new rates for up to 270 days pursuant to G.S. 62-134.

On May 6, 2015, CWSNC filed a revised Appendix A-1 (Company's proposed rates) to its Application. As a result of consultations with the Public Staff – North Carolina Utilities Commission (Public Staff), CWSNC determined that the initially filed Appendix A-1 of the Application needed to be clarified, revised, and amended to properly reflect the new proposed rates being requested in this proceeding.

On May 13, 2015, CWSNC filed a letter stating that given the timing of the filing of the Application, the evidentiary hearing would normally have been set for a date near the end of August or early September, 2015; however, CWSNC requested that the evidentiary hearing date be extended by approximately 30 days in order to allow additional time necessary to complete a major capital project for inclusion in this rate case. CWSNC agreed to waive, for 30 days or until November 29, 2015, its right under G.S. 62-135 to put the suspended rates into effect, temporarily and under bond.

The intervention and participation by the Public Staff was made and recognized pursuant to G.S. 62-15(d) and Rule R1-19(e) of the Rules and Regulations of the Commission. On May 15, 2015, the Corolla Light Community Association, Inc. (CLCA) a customer of CWSNC, filed a petition to intervene, which was granted by the Commission by Order dated May 19, 2015.

On May 22, 2015, the Commission issued its Order Scheduling Hearings and Requiring Customer Notice, scheduling the application for public hearings in Jacksonville, Currituck, Charlotte, Boone, Asheville, and Raleigh, North Carolina, and for evidentiary hearing in Raleigh, North Carolina; establishing the dates for filing testimony; and requiring notice to all affected customers of the proposed rate increase and hearings. On May 26, 2015, the Commission issued a Reissued Order Scheduling Hearings and Requiring Customer Notice. On May 27, 2015, the Commission issued an Errata Order correcting an error in Appendix A-1 of the May 26, 2015 Order.

On June 8, 2015, CWSNC filed its Certificate of Service as required by the May 26, 2015 Order stating under oath that the required customer notice was mailed to all affected customers.

The public hearings were held as scheduled. The following public witnesses testified at the public hearings held in this proceeding:

June 23, 2015	Jacksonville	Larry Campbell
June 24, 2015	Currituck	Dr. Teresa Blaxton
		Hugh McCain
		Lynn Hoffman
		Karen Galganski
		Don Cheek
		Dave Phillips
		Barbara Gernat
		Meade Gwinn
		John Ratzenberger
		Cliff Ogburn
July 7, 2015	Raleigh	Eleanora Tate
July 8, 2015	Charlotte	Brian Allenspach
		Chessley Singleton
		Brian Lucas
		William Schell
		Jack Ritterskamp
July 22, 2015	Boone	Linda Norman
		Brenda Councill
		David Lane

July 23, 2015	Asheville	Connie Brown Emil Revala Ken Allen Sean O'Meara Keith Rice James Tanner Ken Jarvis Mark Innes

On July 1, 2015, CWSNC filed its Ongoing Three-Year Plan for Projects Proposed for "Water and Sewer System Improvement Charge" Eligibility (Ongoing Three-Year Plan).

On July 16, 2015, CWSNC filed a report regarding service quality concerns raised at the public hearing held in Jacksonville on June 23, 2015.

On August 6, 2015, CWSNC filed a report regarding service quality concerns raised at the public hearing held in Raleigh on July 7, 2015.

On August 7, 2015, CWSNC filed a report regarding service quality concerns raised at the public hearing held in Currituck on June 24, 2015.

On August 14, 2015, CWSNC filed a report regarding customer concerns raised at the public hearing held in Charlotte on July 8, 2015.

On August 21, 2015, CWSNC filed the direct testimony and exhibits of CWSNC witnesses David Liskoff, Senior Financial Analyst, Utilities, Inc., and Pauline M. Ahern, Partner, Sussex Economic Advisors, LLC.

On August 27, 2015, CWSNC filed the revised testimony of David Liskoff. As a result of consultations with the Public Staff, CWSNC determined that Exhibit 2 (Appendix A-1) of witness Liskoff's testimony needed to be revised to properly reflect the Company's revised proposed rates being requested in this proceeding.

On September 2, 2015, the Public Staff and CWSNC filed a Stipulation Between Carolina Water Service, Inc. of North Carolina and the Public Staff – North Carolina Utilities Commission Regarding Cost of Capital and Capital Structure Issues (First Stipulation).

On September 4, 2015, CWSNC filed a report regarding service quality concerns raised at the public hearing held in Boone on July 22, 2015.

On September 8, 2015, CWSNC filed a report regarding service quality concerns raised at the public hearing held in Asheville on July 23, 2015.

On September 14, 2015, the Public Staff filed a motion to extend the due date for the filing of Public Staff and Intervenor testimony in this docket to September 25, 2015, and for the filing of rebuttal testimony to September 30, 2015, which was granted by the Commission by Order dated September 16, 2015.

On September 22, 2015, CWSNC filed a notice indicating that it had partially complied with the directive of the Commission from CWSNC's previous rate case proceeding, issued in the March 10, 2014 Order Granting Partial Rate Increase, Approving Rate Adjustment Mechanism, and Requiring Customer Notice, Docket No. W-354, Sub 336, to install meters and fully meter the unmetered systems in Powder Horn, Misty Mountain, Crystal Mountain, Watauga Vista, High Meadows, Ski Country, and Mt. Mitchell prior to the conclusion of CWSNC's current rate case proceeding (the Commission's Meter Installation Directive), having completed installations at five of the seven systems (the First Meter Installation Notice).

On September 25, 2015, the Public Staff filed a second motion to extend the due date for the filing of Public Staff and Intervenor testimony and for the filing of a settlement agreement among all parties to this docket to October 1, 2015, which was granted by the Commission by Order dated September 25, 2015.

On October 1, 2015, CWSNC filed a notice indicating it had fully complied with the Commission's Meter Installation Directive, having completed installations at all seven of the systems (the Second Meter Installation Notice). Also on October 1, 2015, the Public Staff, CWSNC, and CLCA (the Stipulating Parties) filed a Joint Motion to Reschedule Evidentiary Hearing and Extend Filing Dates. In the joint motion, the parties requested that the Commission reschedule the evidentiary hearing in this docket to allow the Company time to conclude 10 nearly-completed or completed but not documented construction projects (Projects) so that those Projects might be included in CWSNC's cost of service once their final costs had been determined and requisite invoices and other documentation provided to the Public Staff for review and verification. Additionally, the parties requested that the Commission grant the Public Staff and CLCA additional time to prefile testimony supporting the settlement agreement reached in this proceeding among the parties.

On October 2, 2015, the Commission issued an Order Rescheduling Evidentiary Hearing and Extending Filing Dates pursuant to which the Commission: (1) continued the evidentiary portion of the October 5, 2015 hearing to a future date and time to be determined and set by further order; (2) approved an extension of time for the finalizing and filing of the settlement agreement and supporting prefiled testimony to a future date to be determined and set by further order; (3) authorized the parties to file recommended dates for the evidentiary hearing and settlement-related testimony on or before Friday, October 9, 2015; and (4) held that the hearing scheduled for October 5, 2015, would be convened for receipt of customer testimony only.

On October 5, 2015, a hearing was convened for the receipt of customer witness testimony. No customers testified.

On October 9, 2015, CWSNC, the Public Staff, and CLCA filed a joint motion setting forth their recommended procedural dates and requesting that certain CWSNC witnesses be excused from appearing at the evidentiary hearing to be held in Raleigh, North Carolina. On October 13, 2015, the Commission issued an Order rescheduling the evidentiary hearing for

October 20, 2015, adopting the procedural schedule proposed by the Stipulating Parties and excusing CWSNC witnesses, David Liskoff and Pauline M. Ahern, from appearing at the evidentiary hearing.

On October 15, 2015, the Stipulating Parties filed a Stipulation, including Stipulation Exhibits A-E (the Second Stipulation), setting forth the terms and conditions of the settlement agreement among the parties. Also on October 15, 2015, the Public Staff filed the testimonies and exhibits of Katherine A. Fernald, Assistant Director, Acounting Division; Windley E. Henry, Supervisor, Water Section, Accounting Division; Fenge Zhang, Staff Accountant, Water Section, Accounting Division; Gina Y. Casselberry, Utilities Engineer, Water Division; and Calvin C. Craig, III, Financial Analyst, Economic Research Division supporting the First and Second Stipulations.

On October 16, 2015, the Public Staff filed a motion requesting that all of its witnesses be excused from appearing at the October 20, 2015 evidentiary hearing and that all of their prefiled testimony and exhibits be copied into the record and received into evidence. On October 19, 2015, the Commission issued an Order granting in part and denying in part the Public Staff's motion, excusing Public Staff witnesses Katherine A. Fernald, Fenge Zhang, and Calvin C. Craig, III, from appearing at the evidentiary hearing and admitting the prefiled testimony and exhibits of those witnesses into evidence. As to Public Staff witnesses Windley E. Henry and Gina Y. Casselberry, the Commission denied the motion to excuse their appearance at the evidentiary hearing.

On October 20, 2015, the evidentiary hearing was held in Raleigh, North Carolina as scheduled. At the hearing, the prefiled testimonies and exhibits offered by CWSNC witnesses Liskoff and Ahern and Public Staff witnesses Casselberry, Henry, Fernald, Zhang, and Craig were copied into the record as if given orally from the witness stand and the exhibits of the witnesses were received into evidence. The Application, including the confidential and public sections of NCUC Form W-1 as well as supplemental filings to the NCUC Form W-1 made on April 10 and April 21, 2015, and also including the revised Appendix A-1 to the Application filed on May 6, 2015, the Ongoing Three-Year Plan, the six reports filed by CWSNC related to service quality concerns, the First Meter Installation Notice, the Second Meter Installation Notice, the First Stipulation, and the Second Stipulation were all received into evidence. At the evidentiary hearing, Public Staff witness Fernald, adopting the testimony of Public Staff witness Henry, and witness Casselberry testified in response to questions from the Commission regarding their prefiled testimony and exhibits. In addition, CWSNC witness Martin J. Lashua, Vice President of Operations, CWSNC, testified in response to questions from the Commission.

On October 23, 2015, in response to a request of the Commission at the evidentiary hearing, CWSNC filed late-filed exhibits consisting of certain wastewater treatment contracts by and between CWSNC and the following counterparties: Johnston County (White Oak area); City of Gastonia/Two Rivers Utilities (Kings Grant); and the Town of Dallas (College Park). CWSNC requested that the Commission enter an order admitting such contracts in evidence as late-filed exhibits.

On October 26, 2015, in response to a request of the Commission at the evidentiary hearing, the Public Staff filed late-filed exhibits detailing the major components of CWSNC's rate case expenses and detailing the calculation of CWSNC's franchise tax amount.

On November 19, 2015, CWSNC, CLCA, and the Public Staff filed a Joint Proposed Order.

On December 2, 2015, in response to a request of the Commission at the evidentiary hearing, CWSNC filed a late-filed exhibit consisting of a letter from the City of Concord regarding the rates charged to CWSNC for purchased water supplied to its customers in the Company's Zemosa Acres service area. CWSNC requested that the Commission enter an order admitting such information in evidence as a late-filed exhibit.

On the basis of the Application; the First Stipulation; the Second Stipulation; the public witnesses testimony; the testimony and exhibits of CWSNC witnesses Liskoff, Ahern, and Lashua; the testimony and exhibits of Public Staff witnesses Fernald, Henry, Zhang, Casselberry, and Craig; and the entire record in this proceeding, the Commission is of the opinion that the provisions of the First Stipulation and Second Stipulation are just and reasonable. Accordingly, the Commission makes the following

FINDINGS OF FACT

1. CWSNC is a corporation duly organized under the law and is authorized to do business in the State of North Carolina. CWSNC is a franchised public utility providing water and sewer utility service to customers in 31 counties in North Carolina. CWSNC is a wholly-owned subsidiary of Utilities, Inc.[1]

2. CWSNC is properly before the Commission pursuant to Chapter 62 of the General Statutes of North Carolina seeking a determination of the justness and reasonableness of its proposed rates and charges for its water and sewer utility operations.

3. CWSNC provides service to approximately 18,123 water customers and 11,985 sewer customers, including 909 sewer customers in the Corolla Light and Monteray Shores (CLMS) service areas and 630 sewer customers in the Nags Head service area.

4. A total of 28 customers testified at the seven public hearings and the evidentiary hearing, with 10 of those customers expressing service-related concerns. Such concerns included sewer system odor problems; a perceived wastewater treatment plant (WWTP) capacity issue; the existence of water leaks; paperless billing issues; staining in toilets; mailing inefficiencies; and unfriendliness of Company personnel. In addition, the majority of the remaining customers who appeared as witnesses testified, in general, in opposition to the proposed rate increase.

[1] Utilities, Inc., owns regulated utilities in approximately 15 states, including several in North Carolina. Presently, the regulated utilities owned by Utilities, Inc. in North Carolina are: (1) Carolina Water Service, Inc. of North Carolina (Docket No. W-354); (2) Bradfield Farms Water Company (Docket No. W-1044); (3) Carolina Trace Utilities, Inc. (Docket No. W-1013); (4) CWS Systems, Inc. (Docket No. W-778); (5) Elk River Utilities, Inc. (Docket No. W-1058); and (6) Transylvania Utilities, Inc. (Docket No. W-1012).

5. CWSNC filed six reports with the Commission, verified by Company Vice President of Operations, Martin J. Lashua, addressing the service-related concerns expressed by the public witnesses who testified at the public hearings. Such reports described each of the witnesses' specific service-related concerns, the Company's response, and how each concern was addressed, if applicable.

6. The overall quality of service provided by CWSNC is adequate.

7. The test period for this rate case is the 12 months ended December 31, 2014, adjusted for certain known and actual changes in plant, revenues, and costs based upon circumstances and events occurring or becoming known through the close of the evidentiary hearing in this proceeding.

8. The present rates for water and sewer service in all of the Applicant's service areas have been in effect since July 1, 2014, pursuant to the Commission's Order issued June 27, 2014, in Docket Nos. M-100, Sub 138 and W-354, Sub 342, and the Commission's Order issued July 8, 2014, in Docket No. W-354, Sub 336.

9. The average monthly residential bills under CWSNC's present and proposed water and sewer rates are as follows:

WATER OPERATIONS

Service Area	Average Usage (Gallons)	Existing	Proposed
Carolina Forest	4,200	$41.10	$35.87
High Vista Estates	4,200	$41.10	$35.70
Riverpointe	4,200	$41.10	$48.93
Whispering Pines	4,200	$41.10	$31.84
White Oak/Lee Forest	4,200	$41.10	$36.12
Winston Plantation	4,200	$41.10	$36.12
Winston Pointe	4,200	$41.10	$36.12
Woodrun	4,200	$41.10	$35.87
Yorktown	4,200	$41.10	$43.51
Zemosa Acres	4,200	$41.10	$44.60
Linville Ridge (flat rate)	n/a	$31.68	$42.51
All other water systems	4,200	$41.10	$50.61

SEWER OPERATIONS

Service Area	Average Usage (Gallons)	Existing	Proposed
White Oak Plantation/Lee Forest/Winston Point	4,200	$43.35	$ 49.97
Kings Grant	4,200	$43.35	$ 46.82
College Park	4,200	$43.35	$ 54.80
Mt. Carmel	4,200	$44.98	$ 54.38
Corolla Light/ Monteray Shores	4,347	$81.17	$103.63
Nags Head	4,750	$62.81	$ 76.11
All other sewer systems	4,200	$43.35	$ 51.96

10. On September 2, 2015, the Public Staff and CWSNC filed a Stipulation regarding cost of capital and capital structure issues (First Stipulation), and on October 15, 2015, CWSNC, the Public Staff, and CLCA filed a Stipulation regarding all remaining terms and conditions (Second Stipulation). The First Stipulation and the Second Stipulation settled all issues between CWSNC, CLCA, and the Public Staff. The Stipulating Parties are the only formal parties to this proceeding.

11. By its Application, CWSNC initially requested a total annual revenue increase in its water and sewer rates of $3,642,251, a 22.25% increase over the total revenue level generated by the rates currently in effect for CWSNC.

12. CWSNC's present and proposed service revenues for the 12-month period ending December 31, 2014, including pro forma adjustments, are shown below:

	Present	Proposed
CWSNC Water Operations	$9,369,220	$10,951,484
CWSNC Sewer Operations	$5,711,794	$ 6,830,366
CLMS[1] Sewer Operations	$1,117,239	$ 1,426,387
Nags Head Sewer Operations	$ 693,575	$ 859,815

13. CWSNC's original cost rate base used and useful in providing service to its customers is:

CWSNC Water Operations	$30,984,960
CWSNC Sewer Operations	$18,868,610
CLMS Sewer Operations	$ 6,668,286
Nags Head Sewer Operations	$ 2,092,182

[1] Corolla Light and Monteray Shores (CLMS).

14. Water and combined[1] sewer plant in service, after pro forma adjustments, are as follows:

Water Operations	$65,332,980
Combined Sewer Operations	$59,815,666

15. Accumulated depreciation consist of the following balances for the water and combined sewer operations:

Water Operations	$17,376,904
Combined Sewer Operations	$13,882,097

16. Contributions in aid of construction (CIAC), reduced by accumulated amortization of CIAC, consist of the following amounts for water and combined sewer operations:

Water Operations	$12,708,624
Combined Sewer Operations	$16,764,979

17. On July 23, 2013, North Carolina Session Law 2013-316 (House Bill 998) was signed into law. Among other things, House Bill 998 added a new section, G.S. 105-130.3C, to the general statutes concerning possible future rate reductions in the corporate state income tax rate. On August 6, 2015, the North Carolina Department of Revenue announced that, pursuant to this new section, the target for the fiscal year ended 2014-2015 had been met, and the state corporate income tax rate will decrease from the current rate of 5% to 4%, effective for taxable years beginning on or after January 1, 2016. It is reasonable and appropriate to calculate state income taxes in this proceeding based on the statutory corporate rate effective January 1, 2016, of 4%. It is reasonable and appropriate to calculate federal income taxes in this proceeding based on the corporate rate of 34%.

18. Due to the reduction in the state corporate income tax rate from 6.9% to 6.0% effective January 1, 2014, and to 5% effective January 1, 2015, CWSNC has excess deferred income taxes. In its May 13, 2014 Order issued in Docket No. M-100, Sub 138, the Commission ordered that excess deferred taxes for all utilities be held in a deferred tax regulatory liability account until they can be amortized as credits to income tax expense in each utility’s next general rate case proceeding. The regulatory liability related to excess deferred income taxes should be amortized over three years, consistent with the amortization period for rate case expense. Since the North Carolina Department of Revenue has announced that the target has been met and the state corporate income tax rate will decrease to 4% effective January 1, 2016, the excess deferred taxes related to the decrease from 5% to 4% in the regulatory liability should also be amortized over three years.

19. It is reasonable and appropriate for CWSNC to recover total rate case expenses of $448,525, consisting of $304,330 related to the current proceeding and $144,195 of unamortized rate case expense from prior proceedings, to be amortized and collected over a three-year period, for an annual level of rate case expense of $149,508.

[1] Combined sewer amounts include CWSNC uniform, CLMS, and Nags Head sewer operations.

20. It is reasonable and appropriate that the unamortized balance of the gain on sale of systems sold to Charlotte Mecklenburg Utility Department as of December 31, 2015, should be amortized over a three-year period.

21. CWSNC's total operating revenue deductions under present rates are:

Water Operations	$7,770,065
Combined Sewer Operations	$6,143,546

22. The testimony of Public Staff witness Craig, regarding the reasonableness of the stipulated capital structure, cost of debt, and return on equity component of the overall rate of return, adequately supports the capital structure consisting of 49.00% long-term debt and 51.00% common equity, the cost of long-term debt of 6.60% and the return on common equity of 9.75% agreed to by CWSNC and the Public Staff in the First Stipulation. The stipulated capital structure and debt and equity returns are just and reasonable and appropriate for use in setting rates in this proceeding. Accordingly, the just, reasonable, and appropriate components of the rate of return for CWSNC are as follows:

a. Long-Term Debt Ratio	49.00%
b. Common Equity Ratio	51.00%
c. Embedded Cost of Debt	6.60%
d. Return on Common Equity	9.75%
e. Overall Weighted Rate of Return	8.20%

23. It is reasonable and appropriate to determine the revenue requirement for CWSNC using the rate base method as allowed by G.S. 62-133.

24. It is reasonable and appropriate to use the statutory regulatory fee rate of 0.148%[1] when calculating CWSNC's revenue requirement.

25. CWSNC's right to charge a Water System Improvement Charge (WSIC) and Sewer System Improvement Charge (SSIC) was granted by the Commission in Docket No. W-354, Sub 336 by Order issued March 10, 2014. Subsequent to the date of issuance of this present Order, that right will apply to CWSNC's Linville Ridge and Nags Head service areas, which were not included in the proceeding in which the Sub 336 Order was issued. Thus, as of the date of this Order, CWSNC's use of the Commission-authorized WSIC/SSIC rate adjustment mechanism shall apply to all of CWSNC's current service areas and customers.

26. Pursuant to Commission Rules R7-39(k) and R10-26(k), the WSIC and SSIC presently in effect are reset at zero as of the effective date of this Order.

[1] The regulatory fee rate of 0.148% became effective July 1, 2015, pursuant to North Carolina Session Law 2015-134 (House Bill 356), which was signed into law on June 30, 2015.

27. The Ongoing Three-Year Plan filed by CWSNC on July 1, 2015, is reasonable and meets the requirements of Commission Rules R7-39(m) pertaining to WSIC and R10-26(m) pertaining to SSIC.

28. The agreed-upon rates will provide CWSNC with an increase in its annual level of authorized service revenues through rates and charges approved in this case by $2,744,314, consisting of an increase for water operations of $1,358,454 and an increase for combined sewer operations of $1,385,860. After giving effect to these authorized increases in water and sewer revenues, the total annual service revenues for the Company will be $19,636,142, consisting of the following levels of just and reasonable service revenues:

Water Operations	$10,727,674
Combined Sewer Operations	$ 8,908,468

29. CWSNC's total operating revenue deductions under the agreed-upon rates, including depreciation and amortization expense for CWSNC's combined operations of $1,983,408, are:

Water Operations	$8,267,879
Combined Sewer Operations	$6,651,402

30. It is reasonable and appropriate for CWSNC to: (1) increase its new sewer customer charge from $20.70 to $22.00; (2) increase the return check fee from $14.11 to $25.00 for Nags Head; (3) increase the returned check charge from $24.00 to $25.00 for Linville Ridge; (4) increase the meter testing fee from $19.20 to $20.00; (5) increase the new water customer charge from $25.92 to $27.00; (6) increase the reconnection charge from $25.92 to $27.00.

31. CWSNC's pump and haul expenses and the new spray charges are not a part of Belvedere's system modification project, but are a result of an extraordinary expense and should continue to be amortized for a 10-year amortization period with no unamortized balance included in rate base. It is reasonable and appropriate that only invoiced costs and not capitalized time or interest during construction be included.

32. In this proceeding, it is reasonable and appropriate for the current, system-specific sewer rates for the CLMS and Nags Head service areas to remain unchanged from those established in Docket No. W-354, Subs 327 and 336 and for CWSNC's remaining revenue sewer requirement to be recovered through its uniform sewer rates for other service areas, as stipulated. In future general rate case proceedings, the issue of rate disparity should be reviewed again by CWSNC, the Public Staff, and any other interested party and appropriate consideration should be given to moving the CLMS and Nags Head service areas toward uniform rates in light of the facts and circumstances that exist at that time.

33. The Schedules of Rates for water and sewer utility service agreed to by CWSNC, the Public Staff, and CLCA, attached hereto as Appendices A-1, A-2, A-3, and A-4, are just and reasonable and should be approved.

34. The First Stipulation and the Second Stipulation contain the provision that the Stipulating Parties agree that none of the positions, treatments, figures, or other matters reflected in the agreements should have any precedential value, nor should they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matters in issue.

35. The First Stipulation and the Second Stipulation contain the provision that the agreements made therein do not bind the Stipulating Parties to the same positions in future proceedings, and the parties reserve the right to take different positions in any future proceedings. The Second Stipulation also contains the provision that no portion of the Second Stipulation is binding on the Stipulating Parties unless the entire Second Stipulation is accepted by the Commission.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The evidence for the following conclusions is contained in the Application; in the First Stipulation; in the Second Stipulation; in the testimony of the public witnesses; in CWSNC's Report on Customer Service Quality Issues From Public Hearing In Jacksonville, North Carolina, filed on July 16, 2015; in CWSNC's Report on Customer Service Quality Issues From Public Hearing In Currituck, North Carolina, filed on August 7, 2015; in CWSNC's Report on Customer Comments From July 6 Hearing In Raleigh, North Carolina, filed on August 6, 2015; in CWSNC's Report on Customer Service Quality Issues From Public Hearing In Charlotte, North Carolina, filed on August 14, 2015; in CWSNC's Report on Customer Service Quality Issues From Public Hearing in Boone, North Carolina, filed on September 4, 2015; in CWSNC's Report on Customer Service Quality Issues From Public Hearing In Asheville, North Carolina, filed on September 8, 2015; in the testimony and exhibits of CWSNC witnesses Liskoff, Ahern, and Lashua; in the testimony and exhibits of Public Staff witnesses Fernald, Henry, Zhang, Casselberry, and Craig; and in the entire record in this proceeding.

<u>Public Hearings and Service Quality</u>

Seven public hearings were held across the State for the benefit of public witnesses. Public witnesses were also given the opportunity to be heard at the evidentiary hearing which was held in Raleigh, North Carolina. Twenty-eight public witnesses testified during those eight hearings; with 10 of those public witnesses expressing service-related concerns.

In response to the customers' complaints, CWSNC filed six reports[1] with the Commission, verified by Company Vice President of Operations, Martin J. Lashua (collectively referenced as Reports on Customer Concerns), addressing the service-related concerns expressed by the public witnesses who testified at the hearings held in this docket. Such reports described each of the

[1] No customers appeared to testify at the public hearing or the evidentiary hearing in Raleigh, North Carolina on October 5, 2015 and October 20, 2015, respectively.

witnesses' specific service-related concerns, the Company's response, and how each concern was addressed, if applicable. The six reports are summarized below:

Jacksonville (June 23, 2015)

Only one customer testified at the Jacksonville public hearing. That witness, Larry Campbell, is a CWSNC sewer customer who primarily testified regarding his concerns related to the magnitude of the requested rate increase.

Currituck (June 24, 2015)

A total of 10 customers testified at the Currituck public hearing, five of whom voiced service quality complaints.

Six of the 10 customers who testified at the Currituck public hearing are CWSNC sewer utility customers who reside in the CLMS service area in Currituck County. Those six witnesses (Dr. Teresa Blaxton, Hugh McCain, Lynn Hoffman, Karen Galganski, Don Cheek, and Dave Phillips) testified primarily in opposition to the proposed rate increase, with the exception of witness Galganski, who testified regarding her perceptions of the Company's reputation for customer service.

Three of the 10 customers who testified at the Currituck public hearing are CWSNC sewer utility customers who reside in the Nags Head service area in Dare County. The fourth Nags Head area witness who testified is not a CWSNC customer, but serves as the Town Manager for the Town of Nags Head. These four witnesses (Barbara Gernat, Meade Gwinn, John Ratzenberger, and Cliff Ogburn) testified regarding customer service quality complaints experienced primarily during peak tourist season months related to (1) sewer system odor problems and (2) perceived WWTP capacity issue.

On April 21, 2015, CWSNC contracted with an engineering firm, Diehl & Phillips, P.A. of Cary, North Carolina, to complete an investigation and evaluation of odor and odor sources at the Village of Nags Head wastewater collection and treatment systems (Odor Investigation Report). The consulting engineer was on site May 28, 29, and 30, 2015, and the consultant's Odor Investigation Report is dated June 25, 2015. A copy of the report was provided to Public Staff Engineer Gina Casselberry. Subsequent to the NCUC public hearing, the Company also sent a letter to the Nags Head Town Manager, Cliff Ogburn, dated July 31, 2015, addressing the capacity and odor issues raised by public witness Ogburn during his testimony at the public hearing. A copy of the full Odor Investigation Report was provided to public witness Ogburn. A copy of the narrative portion of the Odor Investigation Report was also attached as Appendix B to the report filed by CWSNC on August 7, 2015, regarding service quality concerns raised at the public hearing held in Currituck. That report is part of the evidence in this case.

With regard to the odor complaints addressed at the public hearing, CWSNC noted that the Nags Head wastewater treatment site is located in close proximity to homes and businesses in a very confined area on a barrier island. WWTP odors are challenging under the best of circumstances and can be difficult to address and resolve, but CWSNC indicated a willingness to continue to explore any and all reasonable, prudent, and cost-effective options to minimize potentially objectionable odors. In its report to the Commission, CWSNC emphasized that it is fully committed to being responsible and attentive to odor complaints and other concerns expressed by its customers and the Town of Nags Head.

Charlotte (July 8, 2015)

A total of five customers testified at the Charlotte public hearing. None of the witnesses testified as to service quality concerns; rather, all expressed concern related to the proposed rate increase. One of the witnesses, Brian Lucas, President of the Riverpointe Homeowners' Association, testified that the association has a "great" relationship with CWSNC.

Boone (July 22, 2015)

Of the three customers who presented testimony at the Boone public hearing, only two customers raised service quality related concerns. Witness Norman discussed a range of topics, including the installation of meters at the Misty Mountain system, for which she expressed enthusiasm. She also raised a concern about the existence of leaks, based on her understanding of a measurement of "unaccounted" water. She spoke positively about the efforts of CWSNC local personnel to keep her posted on the progress of the meter installation. Finally, she expressed concerns related to her election of paperless billing. CWSNC investigated witness Norman's complaint regarding her paperless billing situation and responded to her by email dated July 23, 2015, providing assurance that the problem had been corrected.

Witness Council testified that, although she is a full time resident, she is gone a lot and feels she is being billed for consumption even when she is not home. CWSNC reported that it first met with public witness Council at her home in February 2013 and then again in July 2015, subsequent to the hearing, to investigate the possibility of a leak. No evidence of a leak was found during either investigation.

Asheville (July 23, 2015)

Of the eight customers who testified at the Asheville public hearing, only two customers raised issues about service or quality, while several of the customers made positive comments about the service they receive, CWSNC personnel, and/or water quality. All of the witnesses expressed concern about the proposed percentage increase in rates.

Witness Brown testified as to mailing efficiencies and as to the unfriendliness of CWSNC staff. CWSNC personnel investigated witness Brown's concerns and responded to her concerns in writing with the results of the investigation. Witness Jarvis testified as to his concerns about water quality, indicating he does not drink the water provided by CWSNC and that the water leaves a ring around his commode. In reviewing customer records for this system for the period January 1, 2014 to July 31, 2015, CWSNC determined that there had been only one taste or odor complaint. CWSNC personnel also discussed with witness Jarvis his concern over toilet staining and pointed out that the cause is most likely from airborne bacteria.

Raleigh (July 7, 2015)

Only one witness, Eleanora Tate, appeared to testify at the public hearing in Raleigh on July 7, 2015. Witness Tate testified regarding odors from the Company's Ashley Hills WWTP. Witness Tate also testified regarding water quality concerns. Although CWSNC does not provide water service to her home, it acknowledged that the water provider is also a Utilities, Inc. company and investigated her water quality complaint. Regarding her complaint related to smelling odors from the WWTP, CWSNC representatives met with Public Staff engineer Gina Casselberry to tour and inspect the Ashley Hills WWTP and community. An attempt was made during the visit to speak with witness Tate, but she was not at home. During the visit, no odor was detected; however, CWSNC noted that witness Tate's home is only a few hundred feet away from the WWTP. Witness Tate was contacted later and encouraged to contact the Company should she have additional concerns.

No customers appeared to testify at the public hearing in Raleigh, North Carolina on October 5, 2015. In addition, no customers appeared to testify at the evidentiary hearing in Raleigh, North Carolina on October 20, 2015.

Public Staff witness Casselberry testified that her investigation included review of customer complaints; CWSNC's record of compliance with the Department of Environmental Quality (DEQ)[1], Surface Water Protection Sections (SWPS) and Public Water Supply Sections (PWSS); and review of Company records and analysis of revenues at existing and proposed rates. Witness Casselberry testified that she had contacted representatives of both the PWSS and SWPS of DEQ regarding the operation of the water and sewer systems. She stated that none of the personnel she contacted had expressed any significant concerns regarding the operation of the water and sewer systems or had identified any major water quality concerns.

In addition, witness Casselberry testified that she had reviewed customer complaints received by the Public Staff as a result of this proceeding. She indicated that all customers objected to the rate increase.

Further, witness Casselberry testified regarding customer concerns related to odor at the Nags Head wastewater treatment plant. Specifically, witness Casselberry testified that on June 24, 2015, she inspected the Nags Head WWTP with CWSNC personnel. She noted that to help eliminate odors at the WWTP, CWSNC has installed odor control chemicals, odor control misters at the headworks (location of bar screens, equalization basin (EQ) and influent) and tertiary filter area near train 4, covered the bar screen with a plastic bag, installed a special proprietary influent device that screens the influent and processes the screening for disposal, replaced the last of the aging AeroMod units, submitted plans to install new tertiary filters, and recently contracted with an engineering firm to conduct an odor study. She noted that she had been provided with the Odor Investigation Report. Noting that CWSNC had communicated to the Public Staff an intention to implement the recommendations of the report, the Public Staff indicated that CWSNC has eliminated the odors as much as can be expected at the Nags Head WWTP.

[1] Formerly known as the Department of Environment and Natural Resources (DENR).

With respect to the Misty Mountain service area in Boone, witness Casselberry testified that in 2015, CWSNC conducted a helium test of Misty Mountain's water mains and detected several leaks, which were repaired. She also indicated that now that CWSNC has installed individual meters, customers will be able to monitor their consumption.

Based upon the foregoing, and after careful review of the testimony of the customers at the public hearings, the Reports on Customer Concerns provided by CWSNC, and the Public Staff's engineering and service quality investigation, the Commission concludes that the overall quality of service provided by CWSNC is adequate.

Capital Structure and Cost of Capital

In its application, which was supported by the direct testimony and exhibits filed by CWSNC witness Ahern, the Company requested an overall cost of capital of 8.54%. Such request was based on a capital structure of 48.97% long-term debt, 51.03% common equity, and an embedded cost of debt of 6.60%, and a return on common equity of 10.40%. Pursuant to the First Stipulation, CWSNC and the Public Staff have agreed that a capital structure consisting of 49.00% long-term debt and 51.00% common equity, an embedded cost of debt of 6.60% and a return on common equity of 9.75% are appropriate for use in this proceeding.

Public Staff witness Craig testified in support of the agreed upon capital structure and cost rates on the components of the capital structure. Witness Craig contended that it is widely recognized that a public utility should be allowed a rate of return on capital that will allow the utility, under prudent management, to attract capital under the criteria or standards referenced by the Hope[1] and Bluefield[2] decisions. He maintained that if the allowed rate of return is set too high, consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. However, if the return is set too low and the utility is not able to attract capital on reasonable terms to meet future expansion for its service area, witness Craig asserted that future service obligations may be impaired. Witness Craig explained that because a public utility is capital intensive, the cost of capital is a very large part of its overall revenue requirement and is a crucial issue for a company and its ratepayers.

With respect to capital structure, witness Craig testified that in this proceeding, through discovery, it was determined that CWSNC was in position to update its capital structure to 48.61% long-term debt and 51.39% common equity; however, as part of the First Stipulation, CWSNC agreed to a lower (i.e., less expensive) cost capital structure consisting of 49.00% long-term debt and 51.00% common equity.

With respect to the cost of common equity, witness Craig testified that his recommendation is based on: (1) the discounted cash flow (DCF) model for water and local natural gas distribution companies (LDCs); (2) the risk premium method using a regression analysis of allowed returns for LDCs; and (3) the comparable earnings analysis on a comparable group of water utilities. He testified that because the common equity of CWSNC is not publically traded, he could not apply the DCF method directly to CWSNC. As such, he applied the DCF method to a comparable group

[1] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).
[2] Bluefield Waterworks & Impr. Co. v. Public Service Comm'n, 262 U.S. 679, 692-93 (1923).

of water utilities and a group of natural gas LDCs. He testified that based upon the DCF results for the comparable group of water utilities, he determined that the cost of common equity is within the range of 8.20% to 9.20%. He testified that applying the risk premium method produced a predicted return on common equity of 9.66%. Finally, he testified that applying the comparable earnings analysis produced a range of 8.70% to 9.80%. Based on the results of the three methods, witness Craig concluded that a reasonable range of estimates for the cost of common equity is between 8.80% and 9.80%.

CWSNC and the Public Staff stipulated that the cost of common equity should be 9.75%, which is supported by witness Craig's analysis.

Witness Craig testified as to the extent to which the recommended cost of common equity takes into consideration the impact of changing economic conditions on customers. He testified that he is aware of no clear numerical basis for quantifying the impact of changing economic conditions on customers in determining an appropriate return on equity in setting rates for a public utility. Rather, he testified that the impact of changing economic conditions nationwide is inherent in the methods and data used in his study to determine the cost of equity for utilities that are comparable in risk to CWSNC. In addition, witness Craig stated that customer testimony at the public hearings in this proceeding focused on the amount of proposed rate increases in the various service areas.

With respect to the overall cost of capital, witness Craig recommended 8.20% as set forth in Exhibit CCC-7 of his testimony. In regard to a reasonableness assessment of financial risk with respect to his recommended return on common equity and overall cost of capital, witness Craig testified that he considered the pretax interest coverage ratio. Witness Craig testified that based upon the recommended capital structure, cost of debt, and common equity return of 9.75%, the pretax interest coverage ratio is approximately 2.9 times.

G.S. 62-133(b)(4) requires the Commission to fix rates for service which will enable a public utility, by sound management, to produce a fair profit for its stockholders, in view of current economic conditions, maintain its facilities and services and compete in the market for capital, and no more. This is the ultimate objective of ratemaking. Utilities Commission v. General Telephone Company, 281 N.C. 318, 189 S.E.2d 705 (1972). The Commission is of the opinion that there is adequate evidence in the record to support the return on equity agreed to by the Public Staff and CWSNC and that such return should allow CWSNC to properly maintain its facilities and services, provide adequate service to its customers, and produce a fair return, thus enabling the Company to attract capital on terms that are fair and reasonable to its customers and investors. Consequently, the Commission finds and concludes that the return on common equity of 9.75% that was agreed to by CWSNC and the Public Staff is just and reasonable and should be approved.

Further, in light of witness Craig's testimony and analysis, the Commission finds and concludes that there is adequate evidence in the record to support the capital structure and cost of debt agreed to by CWSNC and the Public Staff. Therefore, the capital structure consisting of 51.00% common equity and 49.00% long-term debt, a cost of debt of 6.60%, and a return on common equity of 9.75% are appropriate for use in this proceeding considering the impact of changing economic conditions on customers and relevant statutory and case law.

CLMS and Nags Head Sewer Rates

CLMS and Nags Head were designated by the Commission for separate rate treatment in the final Order issued on January 9, 2009, in Docket No. W-354, Sub 314, based, in part, on anticipated changes in the water systems serving those areas, the cost of the substantial upgrade of the wastewater treatment plant that was to serve the CLMS service area, and the expectation that all of the systems located in the Outer Banks, which included CLMS and Nags Head, would be sold. Since the Order was issued in Docket No. W-354, Sub 314, only one of these changes – the upgrade of the CLMS wastewater treatment plant – actually occurred. The water systems were sold to Currituck County, and the sale of the sewer systems did not take place. As a result of the establishment of separate rates, the customers of the CLMS and Nags Head systems experienced significantly higher percentage sewer rate increases in Docket No. W-354, Sub 327, than customers in other areas served by CWSNC under uniform rates. In recognition of these circumstances and events, in Docket No. W-354, Sub 336, the Public Staff, CWSNC, and CLCA entered into a stipulation agreement, which was approved by the Commission, to keep the sewer rates for CLMS unchanged, thus beginning the process of moving CLMS toward uniform rates.

In the present proceeding, Public Staff witness Casselberry testified that the Public Staff again evaluated the rate disparity between the customers in CLMS and Nags Head when compared to CWSNC's uniform sewer customers, the unique character of the service areas in the Outer Banks, which distinguishes it from other uniform sewer service areas, and the significant impact on CWSNC's uniform sewer rates if CLMS and Nags Head were immediately rolled back into those rates.

In the Second Stipulation, the Stipulating Parties asserted that system-specific sewer rates for the CLMS and Nags Head should eventually be eliminated. However, in order to prevent "rate shock" for CWSNC's uniform sewer customers, the Stipulating Parties agreed that the process should be implemented gradually and reevaluated in future rate case proceedings to determine the appropriate consideration that should be given to uniform rate customers and CLMS and Nags Head customers in light of the facts and circumstances that exist at that time. Therefore, as a further step in the process, the Stipulating Parties recommend that in this proceeding the current system-specific sewer rates for CLMS and Nags Head should remain unchanged from those previously established.

Based on the foregoing, and consistent with the Commission's prior determination in Docket No. W-354, Sub 336, the Commission finds and concludes that this provision of the Second Stipulation is just and reasonable. Accordingly, the Commission finds good cause to allow CWSNC to maintain the present system-specific sewer rates for CLMS and Nags Head.

Water System Improvement Charge (WSIC) and
Sewer System Improvement Charge (SSIC)

In the Company's general rate case proceeding in Docket No. W-354, Sub 336, the Commission found it to be in the public interest to authorize CWSNC to implement and utilize a rate adjustment mechanism (WSIC/SSIC rate adjustment mechanism) to recover the incremental depreciation expense and capital costs related to eligible investments in water and sewer infrastructure projects completed and placed in service between general rate case proceedings as provided for in the then-newly enacted G.S. 62-133.12. Thus, CWSNC was authorized to implement a WSIC/SSIC rate adjustment mechanism for recovery of such costs.

As testified by Public Staff witness Fernald, the WSIC and SSIC authorization does not currently apply to the Nags Head and Linville Ridge service areas since they were not part of the rate case proceeding that took place in Docket No. W-354, Sub 336. Because Nags Head and Linville Ridge are included in the current proceeding, CWSNC's Commission-authorized WSIC/SSIC rate adjustment mechanism will now, on a going-forward basis, apply to all of CWSNC's current service areas and customers. In addition, going forward, CWSNC will comply with the Rules and Regulations of the Commission governing implementation of the mechanism.

The Commission's previously authorized water and sewer system improvement charge rate adjustment mechanism continues in effect, although, pursuant to Commission Rules R7-39(k) and R10-26(k), it has been reset at zero as of the effective date of this Order. CWSNC may, under the Rules and Regulations of the Commission, apply for a WSIC/SSIC rate surcharge on February 1, 2016, to become effective April 1, 2016. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC surcharge is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding.

Based on the service revenues set forth in the Second Stipulation and approved herein, the maximum revenues that could be recovered through WSIC/SSIC charges as of the effective date of this Order are:

	Service Revenues		WSIC & SSIC Cap
Uniform water	$10,727,674	x 5% =	$536,384
Uniform sewer	7,097,654	x 5% =	354,883
Corolla/Monteray	1,117,239	x 5% =	55,862
Nags Head	693,575	x 5% =	34,679

Overall Conclusions

The Commission, having carefully reviewed the First Stipulation, the Second Stipulation, and all of the evidence of record, finds and concludes that the First Stipulation and Second Stipulation are the product of the give-and-take settlement negotiations between CWSNC, the Public Staff, and CLCA; that they constitute material evidence; that they are entitled to be given appropriate weight in this proceeding, along with all other evidence in the record; and that they are fully supported by competent evidence in the record. Accordingly, based on the foregoing findings of fact and the entire record in this proceeding, the Commission concludes that the stipulated rates, the stipulated capital structure and rate of return percentages, and all of the other provisions of the First Stipulation and Second Stipulation, which are incorporated herein by reference, are just and reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the First Stipulation and the Second Stipulation are incorporated by reference herein, and are hereby approved in their entirety.

2. That the Schedules of Rates, attached hereto as Appendices A-1, A-2, A-3, and A-4, are hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138.

3. That the Schedules of Rates, attached hereto as Appendices A-1, A-2, A-3, and A-4, are hereby authorized to become effective for service rendered on and after the issuance date of this Order.

4. That the Notices to Customers, attached hereto as Appendices B-1, B-2, and B-3, shall be mailed with sufficient postage or hand delivered to all affected customers in each relevant service area, respectively, in conjunction with the next regularly scheduled billing process.

5. That CWSNC shall file the attached Certificate of Service, properly signed and notarized, not later than 10 days after the Notices to Customers are mailed or hand delivered to customers.

6. That the First Stipulation, the Second Stipulation, and the parts of this Order pertaining to the contents of those agreements shall not be cited or treated as precedent in future proceedings.

7. That, in future general rate case proceedings, the issue of rate disparity shall be reviewed by CWSNC, the Public Staff, and any other interested party and appropriate consideration shall be given to moving the CLMS and Nags Head service areas toward uniform rates in light of the facts and circumstances that exist at that time.

8. That the late-filed exhibits filed by CWSNC on October 23, 2015, the Public Staff on October 26, 2015, and CWSNC on December 2, 2015, are hereby admitted in evidence in this proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the __7th__ day of _December_____, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

APPENDIX A-1
PAGE 1 OF 8

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing water and sewer utility service

in

IN ALL OF ITS SERVICE AREAS IN NORTH CAROLINA
(excluding Corolla Light, Monteray Shores, and Nags Head)

WATER RATES AND CHARGES

Monthly Metered Water Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage):

< 1” meter	$ 22.46
1” meter	$ 56.15
1 1/2” meter	$ 112.30
2” meter	$ 179.68
3” meter	$ 336.90
4” meter	$ 561.50
6” meter	$1,123.00

Usage Charge, per 1,000 gallons:

A.	Treated Water	$ 6.42
B.	Untreated Water (Brandywine Bay Irrigation Water)	$ 4.12
C.	Purchased Water for Resale:	

Service Area	Bulk Provider	
Carolina Forest	Montgomery County	$ 3.19
High Vista Estates	City of Hendersonville	$ 3.15
Riverpointe	Charlotte Water	$ 6.30

Service Area	Bulk Provider		
Whispering Pines	Town of Southern Pines	$	2.23
White Oak Plantation/ Lee Forest	Johnston County	$	3.25
Winston Plantation	Johnston County	$	3.25
Winston Point	Johnston County	$	3.25
Woodrun	Montgomery County	$	3.19
Yorktown	City of Winston-Salem	$	5.01
Zemosa Acres	City of Concord	$	5.27

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

When because of the method of water line installation utilized by the developer or owner, it is impractical to meter each unit or other structure separately, the following will apply:

Sugar Mountain Service Area:
Where service to multiple units or other structures is provided through a single meter, the average usage for each unit or structure served by that meter will be calculated. Each unit or structure will be billed based upon that average usage plus the base monthly charge for a < 1" meter.

Mount Mitchell Service Area:
Service will be billed based upon the Commission-approved monthly flat rate.

Monthly Flat Rate Water Service: (Billed in Arrears) $ 41.70

Availability Rate: (Semiannual)
Applicable only to property owners in Carolina Forest And Woodrun Subdivision in Montgomery County $ 24.70

Availability Rate: (Monthly)
Applicable only to property owners in Linville Ridge Subdivision $ 12.35

Meter Testing Fee: [1/] $ 20.00

APPENDIX A-1
PAGE 3 OF 8

New Water Customer Charge:	$ 27.00

Reconnection Charge: [2/]

If water service is cut off by utility for good cause	$ 27.00
If water service is discontinued at customer's request	$ 27.00

Reconnection Charge: [2/ and 3/] (Linville Ridge-Residential customers only)

If water service is cut off by utility for good cause	Actual Cost

Management Fee: (in the following subdivision only)

Wolf Laurel	$150.00

Oversizing Fee: (in the following subdivision only)

Winghurst	$400.00

Meter Fee:

For <1" meter	$ 50.00
For meters 1" or larger	Actual Cost

Irrigation Meter Installation:	Actual Cost

Uniform Connection Fees: [4/]

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single Family Equivalent)	$ 100.00
Plant Modification Fee (PMF), per SFE	$ 400.00

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PAGE 4 OF 8

The systems where connection fees other than the uniform fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows. These fees are per SFE:

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Amherst	$ 250.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Blue Mountain at Wolf Laurel	$ 925.00	$ 0.00
Buffalo Creek, Phase I, II, III, IV	$ 825.00	$ 0.00

Carolina Forest	$ 0.00	$ 0.00
Chapel Hills	$ 150.00	$ 400.00
Eagle Crossing	$ 0.00	$ 0.00
Forest Brook/Old Lamp Place	$ 0.00	$ 0.00
Harbour	$ 75.00	$ 0.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 300.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Lemmond Acres	$ 0.00	$ 0.00
Linville Ridge	$ 400.00	$ 0.00
Monterrey (Monterrey LLC)	$ 0.00	$ 0.00
Quail Ridge	$ 750.00	$ 0.00
Queens Harbour/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Riverwood, Phase 6E (Johnston County)	$ 825.00	$ 0.00
Saddlewood/Oak Hollow (Summey Bldrs.)	$ 0.00	$ 0.00
Sherwood Forest	$ 950.00	$ 0.00
Ski Country	$ 100.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Wildlife Bay	$ 870.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Winston Plantation	$1,100.00	$ 0.00
Winston Pointe, Phase 1A	$ 500.00	$ 0.00
Wolf Laurel	$ 925.00	$ 0.00
Woodrun	$ 0.00	$ 0.00
Woodside Falls	$ 500.00	$ 0.00

SEWER RATES AND CHARGES

Monthly Metered Sewer Service:

A. Base Facility Charge:

Residential (zero usage) $ 42.50

Commercial (based on meter size with zero usage)

< 1” meter	$ 42.50
1” meter	$ 106.25
1 1/2” meter	$ 212.50
2” meter	$ 340.00
3” meter	$ 637.50
4” meter	$1,062.50
6” meter	$2,125.00

WATER AND SEWER – RATE INCREASE

B.	Usage Charge, per 1,000 gallons (based on metered water usage)	$ 2.91

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

Monthly Metered Purchased Sewer Service:

Collection Charge (Residential and Commercial/SFE)	$ 34.00

Usage Charge, per 1,000 gallons based on purchased water consumption

Service Area	Bulk Provider	
White Oak Plantation/ Lee Forest/Winston Pt.	Johnston County	$ 4.55
Kings Grant	Two Rivers Utilities	$ 3.80
College Park	Town of Dallas	$ 5.70

Monthly Flat Rate Sewer Service:	$ 52.68
Multi-residential customers who are served by a master meter shall be charged the flat rate per unit.	$ 52.68

APPENDIX A-1
PAGE 6 OF 8

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$ 6.60
Usage Charge, per 1,000 gallons based on purchased water consumption	$ 5.73
Monthly Collection Charge (Residential and Commercial/SFE)	$ 27.40

Regalwood and White Oak Estates Subdivision Service Areas:

Monthly Flat Rate Sewer Service	
Residential Service	$ 52.68
White Oak High School	$1,634.66
Child Castle Daycare	$ 203.34
Pantry	$ 108.00

New Sewer Customer Charge: [5/]	$ 22.00

Reconnection Charge: [6/]

If sewer service is cut off by utility for good cause	Actual Cost

Carolina Pines Subdivision Connection Fees: (sewer only)

Residential	\$1,350.00 per unit (including single family homes, condominiums, apartments, and mobile homes)
Hotels	\$750.00 per unit
Nonresidential	\$3.57 per gallon of daily design of discharge or \$900.00 per unit, whichever is greater

Uniform Connection Fees: [4/]

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single Family Equivalent)	\$ 100.00
Plant Modification Fee (PMF), per SFE	\$1,000.00

The systems where connection fees other than the uniform fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows. These fees are per SFE:

Subdivision	CC	PMF
Abington	\$ 0.00	\$ 0.00
Abington, Phase 14	\$ 0.00	\$ 0.00
Amber Acres North (Phases II & IV)	\$ 815.00	\$ 0.00
Ashley Hills	\$ 0.00	\$ 0.00
Amherst	\$ 500.00	\$ 0.00
Bent Creek	\$ 0.00	\$ 0.00
Brandywine Bay	\$ 100.00	\$1,456.00
Camp Morehead by the Sea	\$ 100.00	\$1,456.00
Hammock Place	\$ 100.00	\$1,456.00
Hestron Park	\$ 0.00	\$ 0.00
Hound Ears	\$ 30.00	\$ 0.00
Independent/Hemby Acres/Beacon Hills (Griffin Bldrs.)	\$ 0.00	\$ 0.00
Kings Grant/Willow Run	\$ 0.00	\$ 0.00
Kynwood	\$ 0.00	\$ 0.00
Mt. Carmel/Section 5A	\$ 500.00	\$ 0.00
Queens Harbor/Yachtsman	\$ 0.00	\$ 0.00
Riverpointe	\$ 300.00	\$ 0.00

Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Steeplechase (Spartabrook)	$ 0.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Willowbrook (Phase 3)	$ 0.00	$ 0.00
Winston Pointe (Phase 1A)	$2,000.00	$ 0.00
Woodside Falls	$ 0.00	$ 0.00

MISCELLANEOUS UTILITY MATTERS

Charge for Processing NSF Checks:	$ 25.00
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Bills shall be rendered monthly in all service areas, except for Mt. Carmel, which will be billed bimonthly; **Availability rates will be billed semiannually in Carolina Forest and Woodrun Subdivisions and monthly for Linville Ridge Subdivision.
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Notes:

1/ If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20.00 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

2/ Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

3/ The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice.

4/ These fees are only applicable one time, when the unit is initially connected to the system.

5/ This charge shall be waived if customer is also a water customer within the same service area.

[6/] The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice. This charge will be waived if customer also receives water service from Carolina Water Service within the same service area. Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 344, on this the _7th___ day of _December__, 2015.

APPENDIX A-2
PAGE 1 OF 3

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing sewer utility service

in

COROLLA LIGHT AND MONTERAY SHORES SERVICE AREA

SEWER RATES AND CHARGES

Monthly Metered Sewer Service (Residential and Commercial):

Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 52.26
1" meter	$ 130.65
1 1/2" meter	$ 261.30
2" meter	$ 418.08
3" meter	$ 783.90
4" meter	$1,306.50
6" meter	$2,613.00

Usage Charge, per 1,000 gallons (based on purchased water usage)	$ 6.65

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

New Sewer Customer Charge:	$ 22.00
Reconnection Charge: [1/]	
If sewer service cut off by utility for good cause	Actual Cost

Uniform Connection Fees: [2/]

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single Family Equivalent)	$ 100.00
Plant Modification Fee (PMF), per SFE	$1,000.00

The systems where connection fees other than the uniform fees have been approved and/or allowed to become effective by the North Carolina Utilities Commission are as follows. These fees are per SFE:

Subdivision	CC	PMF
Corolla Light	$ 700.00	$ 0.00
Monteray Shores	$ 700.00	$ 0.00
Monteray Shores (Degabrielle Bldrs.)	$ 0.00	$ 0.00
Corolla Bay[3/]	$ 100.00	$1,000.00
Corolla Bay[4/]	$ 700.00	$ 0.00
Corolla Shores	$ 700.00	$ 0.00

One SFE shall equal 360 gallons per day of capacity.

MISCELLANEOUS UTILITY MATTERS

Charge for Processing NSF Checks:	$ 25.00
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Bills shall be rendered monthly
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

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PAGE 3 OF 3

Notes:

[1/] The Utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish the estimate to the customer with cut-off notice.

Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

[2/] These fees are only applicable one time, when the unit is initially connected to the system.

[3/] The connection charge of $100 per SFE and the plant modification fee of $1,000 per SFE specified herein apply to new wastewater connections requested at Corolla Bay prior to June 4, 2015.

[4/] The connection charge of $700 per SFE applies to new wastewater connections requested at Corolla Bay on and after June 4, 2015.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 344, on this the _7th__day of __December_, 2015.

APPENDIX A-3
PAGE 1 OF 2

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing sewer utility service

in

NAGS HEAD SERVICE AREA

SEWER RATES AND CHARGES

Monthly Metered Sewer Service: (Commercial)

WATER AND SEWER – RATE INCREASE

A. Base Facility Charge (based on meter size with zero usage)

< 1" meter	$ 18.48
1" meter	$ 46.22
1 1/2" meter	$ 92.42
2" meter	$ 147.88
3" meter	$ 277.27
4" meter	$ 462.12
6" meter	$ 924.24

B. Usage Charge, per 1,000 gallons (based on metered water usage) — $ 9.33

C. Minimum Monthly Charge — $ 62.81

Monthly Flat Rate Sewer Service: $ 62.81

Multi-residential customers who are served by a master meter shall be charged the flat rate per unit

New Sewer Customer Charge: $ 22.00

APPENDIX A-3
PAGE 2 OF 2

Reconnection Charge: [1/]
If sewer service cut off by utility for good cause — Actual Cost

Uniform Connection Fees: [2/]
The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single Family Equivalent)	$ 100.00
Plant Modification Fee (PMF), per SFE	$1,000.00

MISCELLANEOUS UTILITY MATTERS

Charge for Processing NSF Checks:	$ 25.00
Bills Due:	On billing date
Bills Past Due:	21 days after billing date
Billing Frequency:	Bills shall be monthly for service in arrears

Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Notes:

[1/] The Utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish the estimate to the customer with cut-off notice.

Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

[2/] These fees are only applicable one time, when the unit is initially connected to the system.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 344, on this the _7th__day of __December_, 2015.

APPENDIX A-4

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

WATER AND SEWER SYSTEM IMPROVEMENT CHARGES

WATER SYSTEM IMPROVEMENT CHARGE:

All CWSNC water systems	0.00% [1/ and 3/]

SEWER SYSTEM IMPROVEMENT CHARGE:

All CWSNC sewer systems except as noted below	0.00% [2/ and 3/]
Corolla Light and Monteray Shores service area	0.00% [2/ and 3/]
Nags Head service area	0.00% [2/ and 3/]

Notes:

[1/] The Water System Improvement Charge shall be applied to the total water utility bill of each customer under the Company's applicable rates and charges.

[2/] The Sewer System Improvement Charge shall be applied to the total sewer utility bill of each customer under the Company's applicable rates and charges.

[3/] Pursuant to Commission Rules R7-39(k) and R10-26(k), the water system improvement charge and the sewer system improvement charge are reset at zero as of the effective date of new base rates established in a utility's general rate case.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 344, on this the _7th __day of ___December__, 2015.

APPENDIX B-1
PAGE 1 OF 4

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 344

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Water Service, Inc. of North Carolina, 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina	))))))	NOTICE TO CUSTOMERS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina (CWSNC) to increase rates for water and sewer utility service in all of its service areas in North Carolina (including Linville Ridge, but excluding Corolla Light, Monteray Shores, and Nags Head). The new approved rates are as follows:

WATER RATES AND CHARGES

MONTHLY METERED WATER RATES: (Residential and Commercial)

Base Facility Charge
(based on meter size with zero usage)

< 1"meter	$ 22.46
1" meter	$ 56.15
1 1/2" meter	$ 112.30
2" meter	$ 179.68
3" meter	$ 336.90
4" meter	$ 561.50
6" meter	$1,123.00

WATER AND SEWER – RATE INCREASE

Usage Charge, per 1,000 gallons

A. Treated Water	$	6.42
B. Untreated Water (Brandywine Bay Irrigation Water)	$	4.12

C. Purchased Water for Resale

Service Area	Bulk Provider	Usage Charge/ 1,000 gallons
Carolina Forest	Montgomery County	$ 3.19
High Vista Estates	City of Hendersonville	$ 3.15
Riverpointe	Charlotte Water	$ 6.30
Whispering Pines	Town of Southern Pines	$ 2.23
White Oak Plantation/ Lee Forest	Johnston County	$ 3.25
Winston Plantation	Johnston County	$ 3.25
Winston Pointe	Johnston County	$ 3.25
Woodrun	Montgomery County	$ 3.19
Yorktown	City of Winston-Salem	$ 5.01
Zemosa Acres	City of Concord	$ 5.27

MONTHLY FLAT WATER RATE: $ 41.70

Note: Customers in Linville Ridge Subdivision will now be billed monthly for service in arrears.

AVAILABILITY RATES (semiannual):

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County $ 24.70

AVAILABILITY RATES (monthly):

Applicable only to property owners in Linville Ridge $ 12.35

WATER AND SEWER – RATE INCREASE

SEWER RATES AND CHARGES

MONTHLY METERED SEWER RATES:

A. Base Facility Charge

Residential (zero usage)	$ 42.50

Commercial (based on meter size with zero usage)	
<1" meter	$ 42.50
1" meter	$ 106.25
1 1/2" meter	$ 212.50
2" meter	$ 340.00
3" meter	$ 637.50
4" meter	$1,062.50
6" meter	$2,125.00

B. Usage Charge, per 1,000 gallons (based on metered water usage)	$ 2.91

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

MONTHLY METERED PURCHASED SEWER SERVICE:

Collection charge (Residential and Commercial/SFE)	$ 34.00

Usage charge, per 1,000 gallons based on purchased water consumption

Service Area	Bulk Provider	Usage Charge/ 1,000 gallons
White Oak Plantation/ Lee Forest/Winston Pointe	Johnston County	$ 4.55
Kings Grant	Two Rivers Utilities	$ 3.80
College Park	Town of Dallas	$ 5.70

MONTHLY FLAT SEWER RATE:	$ 52.68

WATER AND SEWER – RATE INCREASE

<u>MT. CARMEL SUBDIVISION SERVICE AREA</u>:

Monthly Base Facility Charge	$ 6.60
Usage Charge/1,000 gallons (based on metered water usage)	$ 5.73
Monthly Collection Charge (Residential and Commercial/SFE)	$ 27.40

<u>REGALWOOD AND WHITE OAK ESTATES SUBDIVISION SERVICE AREAS</u>:

Monthly Flat Rate Sewer Service:

Residential Service	$ 52.68
White Oak High School	$1,634.66
Child Castle Daycare	$ 203.34
Pantry	$ 108.00

<u>RATE ADJUSTMENT MECHANISM</u>:

The Commission-authorized water and sewer system improvement charge (WSIC/SSIC) rate adjustment mechanism continues in effect and will now be applicable to customers in CWSNC's Linville Ridge service area. It has been reset at zero in the Docket No. W-354, Sub 344 rate case, but CWSNC may, under the Rules and Regulations of the Commission, apply for a rate surcharge on February 1, 2016, to become effective April 1, 2016. The WSIC/SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-354 Sub 344".

ISSUED BY ORDER OF THE COMMISSION.
This the __7th__ day of ____December_, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

APPENDIX B-2
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 344

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc.	)	
of North Carolina, 2335 Sanders Road,	)	NOTICE TO CUSTOMERS
Northbrook, Illinois 60062, for Authority to	)	IN COROLLA LIGHT AND
Adjust and Increase Rates for Water and Sewer	)	MONTERAY SHORES
Utility Service in All of Its Service Areas in	)	SERVICE AREA
North Carolina.	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina (CWSNC) to charge the following rates for sewer utility service in its Corolla Light and Monteray Shores service area in North Carolina. These are the same rates that were in effect prior to the completion of this general rate case proceeding. The rates for customers in the Corolla Light and Monteray Shores service area were not changed (increased or decreased) in any manner.

SEWER RATES AND CHARGES

MONTHLY METERED SERVICE: (Residential and Commercial)
Base Facility Charge (based on meter size with zero usage)

<1" meter	$ 52.26
1" meter	$ 130.65
1 1/2" meter	$ 261.30
2" meter	$ 418.08
3" meter	$ 783.90
4" meter	$1,306.50
6" meter	$2,613.00

Usage Charge, per 1,000 gallons (based on purchased water usage)	$ 6.65

APPENDIX B-2
PAGE 2 OF 2

RATE ADJUSTMENT MECHANISM:

The Commission-authorized sewer system improvement charge (SSIC) rate adjustment mechanism continues in effect. It has been reset at zero in the Docket No. W-354, Sub 344 rate case, but CWSNC may, under the Rules and Regulations of the Commission, apply for a rate surcharge on February 1, 2016, to become effective April 1, 2016. The SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for sewer system improvement. The SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-354 Sub 344".

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of December, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

APPENDIX B-3
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 344

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc. of	)	
North Carolina, 2335 Sanders Road,	)	NOTICE TO CUSTOMERS
Northbrook, Illinois 60062, for Authority to	)	IN NAGS HEAD
Adjust and Increase Rates for Water and Sewer	)	SERVICE AREA
Utility Service in All of Its Service Areas in	)	
North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina (CWSNC) to charge the following rates for sewer utility service in its Nags Head service area in North Carolina. These are the same rates that were in effect prior to the completion of this general rate case proceeding. The rates for customers in the Nags Head service area were not changed (increased or decreased) in any manner.

SEWER RATES AND CHARGES

MONTHLY METERED SERVICE: (Commercial)

Base Facility Charge (based on meter size with zero usage)

<1" meter	$ 18.48
1" meter	$ 46.22
1 1/2" meter	$ 92.42
2" meter	$ 147.88
3" meter	$ 277.27
4" meter	$ 462.12
6" meter	$ 924.24

Usage charge, per 1,000 gallons	$ 9.33
Minimum Monthly Charge	$ 62.81

APPENDIX B-3
PAGE 2 OF 2

MONTHLY FLAT SEWER RATE: $ 62.81

RATE ADJUSTMENT MECHANISM:

The Commission-authorized sewer system improvement charge (SSIC) rate adjustment mechanism continues in effect and will now be applicable to customers in CWSNC's Nags Head service area**.** It has been reset at zero in the Docket No. W-354, Sub 344 rate case, but CWSNC may, under the Rules and Regulations of the Commission, apply for a rate surcharge on February 1, 2016, to become effective April1, 2016. The SSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for sewer system improvement. The SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-354 Sub 344".

ISSUED BY ORDER OF THE COMMISSION.
This the __7th__ day of ____December___, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Jackie Cox, Deputy Clerk

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-354, Sub 344, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2015.

By: ___________________________________
Signature

____
Name of Utility Company

The above named Applicant, ___________________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-354, Sub 344.

Witness my hand and notarial seal, this the ___ day of _______________, 2015.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ___________________________________

DOCKET NO. W-1130, SUB 8

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Sandler Utilities at Mill Run, LLC, 448 Viking Drive, Suite 220, Virginia Beach, Virginia 23452, for Authority to Increase Rates for Sewer Utility Service in Eagle Creek Subdivision in Currituck County, North Carolina	))))))	RECOMMENDED ORDER GRANTNG RATE INCREASE, REQUIRING REFUND, AND CUSTOMER NOTICE

HEARD: 7:00 p.m., Thursday, September 24, 2015, in the Currituck County Courthouse, Courtroom C, 2801 Caratoke Highway, Currituck, North Carolina

BEFORE: Ronald D. Brown, Hearing Examiner

APPEARANCES:

For Sandler Utilities at Mill Run, LLC:

No attorney

For the Using and Consuming Public:

William E. Grantmyre, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On April 30, 2015, Sandler Utilities at Mill Run, LLC (Sandler), filed an application seeking authority to increase its rates for providing sewer utility service in Eagle Creek Subdivision in Currituck County, North Carolina. By Order issued May 27, 2015, the Commission declared the matter to be a general rate case pursuant to G.S. 62-137, suspended the proposed rates for up to 270 days pursuant to G.S. 62-134, and scheduled the matter for public hearing subject to cancellation if no significant protests were received within 45 days of the date of the customer notice. Sandler filed a certificate of service on June 8, 2015, indicating that customer notice had been given as required.

On September 4, 2015, the Public Staff filed a Notice of Affidavit and the affidavit of Calvin C. Craig, III, Financial Analyst with the Economic Research Division, the testimony of Iris Morgan, Staff Accountant with the Accounting Division, and the testimony of Babette McKemie, Utilities Engineer with the Water and Sewer Division.

The Commission received 15 customer letters protesting the applied for increase with many complaining of service issues, primarily sewer backups, particularly during periods of heavy rainfalls.

The public evidentiary hearing was held as scheduled on Thursday, September 24, 2015, in the Currituck County Courthouse, Currituck, North Carolina. Customers testifying at the hearing were Gary Lickfeld, Dixon Dreher, Denise Hawley-President of the Eagle Creek Homeowners' Association, and John Fedele. Bill Freed, the President of Enviro-Tech, the wastewater utility system contract operator, testified on behalf of Sandler. The Sandler verified application was admitted into evidence. Public Staff Engineer Babette McKemie testified. The pre-filed testimony of Public Staff Accountant Iris Morgan and the Affidavit of Public Staff Financial Analyst Calvin C. Craig, III, were admitted into evidence.

Based upon the verified Application, the testimony of the public witnesses, the testimony of the Sandler witness, the testimony and affidavit of the Public Staff witnesses and exhibits received into evidence at the hearing, and the record as a whole, the Hearing Examiner now makes the following

FINDINGS OF FACT

1. Sandler is a public utility as defined by G.S. 62-3(23) and is authorized to provide sewer utility service in its service area in Eagle Creek Subdivision in Currituck County, North Carolina, pursuant to a franchise granted by the Commission by order issued in Docket No. W-1130, Sub 0.

2. Sandler is properly before the Commission pursuant to G.S. 62-133 for a determination of the justness and reasonableness of its proposed rates and charges.

3. The test period appropriate for use in this proceeding is the 12 months ended December 31, 2013.

4. Sandler provides sewer utility service to approximately 420 residential customers, the Mill Run Golf Club and Moyock Middle School using a vacuum type collection system and 350,000 gallon per day (gpd) wastewater treatment plant which is currently limited by the Division of Water Quality (DWQ) of the North Carolina Department of Environment and Natural Resources to 175,000 gpd of flow. The effluent is permitted for disposal into an infiltration pond and by spray irrigation onto the golf course.

5. The overall quality of service provided by Sandler to its customers in Eagle Creek Subdivision is only marginally adequate.

6. Sandler's present and proposed rates for sewer utility service in Eagle Creek area are:

	Present	Proposed
Residential monthly flat rate:	$ 45.75	$ 60.05
Commercial monthly flat rate:		
Golf Club	$315.00	$ 413.47
School	$766.00	$1,005.45

7. Sandler's annual level of service revenues under present and proposed rates is $243,552 and $319,679 respectively. The present rates service revenues are reduced by $6,760 of uncollectibles at the end of the test year after Public Staff adjustments.

8. Sandler's reasonable original cost rate base at December 31, 2013, after all Public Staff adjustments, is $117,951, consisting of the following items:

Plant in service	$2,206,202
Accumulated depreciation	(177,266)
Contributions in aid of construction (CIAC)	(1,937,599)
Cash working capital	26,614
Average tax accruals	-0-
Original cost rate base	$ 117,951

9. The reasonable level of operating expenses under current rates to include in this proceeding is $212,912, which consist of the following components:

Contract labor	$ 72,084
Procurement fees	10,986
Labor	13,850
Administrative and office	842
Telemetry	777
Maintenance and repairs	1,650
Materials	3,186
Equipment	526
Electric power	37,996
Testing	6,696
Chemicals	16,281
Sludge removal	16,758
Disposal expense	3,051
Purchased water	2,767
Permit fees and licenses	2,120
Business license fees	327
Rate case expense	964
Insurance expense	12,243
Overhead expense	9,808
Total operating expenses:	$212,912

10. The depreciation, amortization, and taxes under rates approved in this proceeding total $41,870, summarized as follows:

Depreciation expense	$36,282
CIAC amortization expense	-0-
Property tax	-0-
Other taxes	952
Regulatory fee	405
Gross receipts tax	-0-
State income tax	920
Federal income tax	3,311
Total depreciation, amortization, and taxes	$41,870

11. The operating ratio method of setting rates is appropriate for use in this proceeding. A return of 7.5% on operating revenue deductions is just and reasonable for use in this proceeding. The operating revenue deductions requiring a return total $250,146.

12. The total annual service revenues necessary to allow Sandler the opportunity to earn the 7.50% return found just and reasonable are $280,303. The rates approved herein will produce annual service revenues of $280,303, which represents an increase of $36,751 or 15.09% over total annual service revenues produced by existing rates.

13. The following rates will produce the annual level of service revenues approved in this Order:

Residential monthly flat rate	$ 52.65
Commercial monthly flat rate:	
Golf Club	$365.00
School	$885.00

FINDING OF FACTS ON TAX ISSUES

14. It is appropriate to calculate income taxes based on the state corporate income tax rate of 4%, effective January 1, 2016, and the statutory federal corporate income taxes for the level of income after all adjustments.

15. Pursuant to House Bill 41 (HB 41) enacted on April 9, 2015, which required that the Commission adjust rates set for water and wastewater companies to reflect the repeal of the gross receipts tax and the reduction in the state corporate income tax rate, and the Commission's June 30, 2014 Order in Docket No. M-100, Sub 138, Sandler should refund to its customers the portion of rates related to the repeal of the gross receipts tax and reduction in the state corporate income tax. This refund should be made through a bill credit to each customer of 6.19% of the amount billed on and after July 1, 2014, until the new rates approved in this docket go into effect.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

The evidence for these findings of fact is contained in the application and the Commission's records. This evidence is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-5

The evidence for these findings of fact is contained in the application, the Commission's records, the testimony of the customers, the testimony of Sandler witness Bill Freed, and the testimony of Public Staff Engineer McKemie.

Gary Lickfeld testified that he has experienced numerous service issues over the past 13 years that he has been a Sandler customer. He testified in 2011 that the Air Vac valve pit package in his yard, serving his and his neighbors residences, was sinking into the ground. This resulted in sewage backups into the toilets and bathtubs in both his and his neighbors residences. Mr. Lickfield testified that sewer backups occur in Eagle Creek during periods of heavy rainfall.

Mr. Lickfeld further testified in February 2015 that he experienced more sewage backups through his toilet and under the toilet. He testified that after speaking with an Enviro-Tech employee, he purchased from Air Vac a backflow valve for which materials and labor cost $300 to install.

Dixon Dreher testified that he has been a customer for more than 10 years and that having served on the Board of Directors of the Homeowners Association he knows sewage backups have occurred in the Greenview area and the Phase 2 and 3 areas.

Denise Hawley, the President of the homeowners association, testified she was contacted in February 2015 by several residents from the Eagleton Circle area when there was a major sewer backup into the ditches near their homes. She testified Bill Freed’s Enviro-Tech team did an awesome job correcting the problem. She testified that during the February 2015 service problems, she learned the wastewater collection system including the Air Vac valve pit packages haven’t been maintained over a period of time. She expressed the need for Sandler to fix the Air Vac valve pit packages immediately and that there be put in place a thorough maintenance plan.

Paul Griffith testified that several years ago he experienced sewage backing up and coming out of the sewer service line valve (Candy Cane) in his yard.

John Fedele testified he has been a customer for more than 10 years and although he has not experienced a sewage backup, he knows other customers that have.

Public Staff Engineer McKemie testified describing the components of the wastewater system. She testified the sewer system consists of a vacuum type collection system with approximately 212 Air Vac pit packages located near the property lines with most of these pits serving two houses. The wastewater from the houses flows to the Air Vac valve pit package and then through a main vacuum line to the wastewater treatment plant.

She further testified the wastewater treatment plant is a 350,000 gallon per day (gpd) extended aeration plant currently limited to 175,000 gpd of flow until certain improvements are made to the wastewater treatment plant.

Ms. McKemie testified that the permit also provides that prior to adding any wastewater to the facility from other sources (outside Eagle Creek subdivision) the permittee shall submit an updated or new agreement between Mill Run Golf Club (Golf Club) and the permittee, with clear language specifying the wastewater from new sources is allowed to be sprayed on the Mill Run Golf Club golf course (Golf Course).

She testified that the permit allows for spray irrigation of 175,000 gpd of effluent onto the Golf Course and 90,000 gpd into an infiltration pond. The effluent is only sprayed on the golf course when it meets the required limits. Wastewater effluent not meeting the limits is disposed of using only the infiltration pond.

Ms. McKemie further testified the Golf Club installed an irrigation system with Sandler, as successor in interest to the original developer, to pay for the costs of any upgrades needed because of the effluent disposal requirements. The Golf Club accepts wastewater effluent generated only from the Eagle Creek subdivision and the school.

Public Staff witness McKemie further testified that she reviewed the DWQ inspection reports from 09/25/2012, 11/20/2013, and the most recent, dated 04/22/2015. The wastewater treatment plant has had continuous compliance issues concerning the functioning of the disinfection equipment, and the proper operation of the golf course spray system. DWQ continues to work with Sandler to address these issues and bring the system into full compliance. She testified these were also issues noted at the time of Sandler's last rate case. Additionally, there was an incidence of a malfunction of the vacuum sewer collection system which resulted in a sewage overflow into a customer's home on February 11, 2015.

Ms. McKemie testified that, on August 12, 2015, she met on-site with Bill Freed, Operation in Responsible Charge, and David May and Allen Clark from the DWQ Washington Regional Office. It was observed that the second bank of UV disinfection was not operational. Also, she observed that there are some number of Air Vac valve pit packages which are located in low areas. It was explained that these Air Vac valve pit packages may fill with rain water during heavy rains. She testified this results in a system malfunction, loss of vacuum and can even result in sewage backing up in a home, when the sewage cannot drain into the system.

Ms. McKemie testified the Public Staff recommends that the Hearing Examiner order that Sandler: (a) within 60 days of the effective date of the order approving rate increase, physically inspect every Air Vac valve pit package and file with the Commission a report on the status of every Air Vac valve pit package as to whether the pit package is subject to rain water intrusion during heaving rains; (b) within 150 days of the effective date of the rate increase order, complete renovations to reduce the rain water intrusion, including but not limited to raising and sealing pit packages subject to rain water intrusion; (c) within 180 days of the effective date of the rate increase order, file a written report with the Commission describing the completed renovations for each of the pit packages where renovations are necessary.

Ms. McKemie further stated the continued problems with the second bank of UV lights are unacceptable and must be remedied within six months of the effective date of the rate increase order.

Bill Freed, the President of Enviro-Tech, testified he has 30 year's experience operating wastewater treatment systems and is a Grade 4 wastewater treatment plant operator, which is the highest grade in North Carolina. He testified there are 212 Air Vac valve pit packages and four to five miles of collection pipe that has to be maintained under 20 to 22 inches of vacuum 24 hours a day, 7 days a week for the system to operate properly. He testified if water gets in the valve and it sticks open, or the valve wears out and sticks open, or the valve sticks open for any reason, the entire collection system will lose vacuum.

Mr. Freed testified that when a valve starts leaking, the clock starts and if that valve is not discovered and repaired within an hour to an hour and a half, other pit package valves are going to fail the same way. He testified it is urgent that his men hurry to find the leaking valve and get it stopped.

The Hearing Examiner concludes that the service provided is only marginally adequate despite the very able and conscientious work by Enviro-Tech, the contract operator. Sandler needs to materially increase its maintenance and repair of the Air Vac valve pit packages and institute a system wide thorough maintenance plan. The Air Vac valve pit package and candy cane service line valve sewage overflows, and the sewage backups into houses are unacceptable.

The uncontroverted testimony was that if water gets in the valve of the Air Vac valve pit packages and the valve sticks open, or the valve wears out and sticks open, or the valve sticks open for any reason, the entire collection system will lose vacuum and fail to transport the sewage. The uncontroverted testimony was that when a valve in an Air Vac valve pit package starts leaking, that valve must be discovered and repaired within an hour or an hour and a half, or other pit package valves will fail the same way, causing collection system failure.

The Hearing Examiner concludes that the Public Staff recommendations that Sandler physically inspect all 212 Air Vac valve pit packages and complete necessary renovations to reduce rain water intrusion will be helpful to reduce future Air Vac valve pit package valve sticking open failures, but additional renovations are needed in order to minimize the impact on the remainder of the collection system from the one failed valve sticking open.

The Hearing Examiner concludes that in addition to the Public Staff recommended Air Vac valve pit package inspections and renovations, and the Public Staff recommended and DWQ required renovations to the second bank of UV lights, that Sandler must within sixty days of the effective date of this order, file with the Commission a detailed plan for the isolation of sections of the Eagle Creek sewer collection system, including the installation of isolation valves to minimize the system wide impact of Air Vac valve pit package valves sticking open, and also plans for the installation of any other necessary equipment to prevent the collection system losing its vacuum. The Hearing Examiner concludes that Sandler shall complete the necessary installations to achieve the isolation of collection system sections and installation of additional equipment to prevent the loss of collection system vacuum, within 150 days of the effective date of this order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

The evidence for these findings of fact is contained in the Application, the records of the Commission, and the testimony of Public Staff Engineer McKemie and Public Staff Accountant Morgan. This evidence is uncontroverted. The service revenues under present and Sandler proposed rates are stated on page 9 of McKemie’s pre-filed testimony, and the uncollectibles are reflected on Morgan Exhibit 1, Schedule 3.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

The evidence for these findings of fact is contained in the testimony of Public Staff Accountant Morgan. This evidence is uncontroverted. The original cost rate base of $117,951 and the reasonable level of operating expenses of $212,912 are set forth in Morgan Exhibit 1 Schedules 2 and 3.

Based on the foregoing, the Hearing Examiner finds and concludes that the Company's reasonable original cost rate base is $117,951.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the testimony of Public Staff Accountant Morgan in Morgan Exhibit 1, Schedule 3. This evidence is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for the operating revenue deductions requiring a return totaling $250,146 is found in the testimony of Public Staff Accountant Morgan, Morgan Exhibit 1, Schedule 1, Line 2, column (c).

The evidence for the remainder of this finding of fact is contained in the affidavit of Public Staff witness Craig.

In his affidavit, Mr. Craig recommends using the operating ratio method for determining the overall fair rate of return in this proceeding pursuant to G.S. 62-133.1(a). Sandler did not oppose the use of the operating ratio method for determining the overall fair rate of return in this proceeding pursuant to G.S. 62-133.1(a).

The Hearing Examiner has carefully considered the evidence and concludes that the operating ratio methodology as described in G.S. 62-133.1(a) is reasonable for use in this proceeding.

In his affidavit, Mr. Craig recommended that the Company be granted a 7.50% margin on expenses. His recommendation would produce operating ratios of 93.14% (including taxes) and 93.02% (excluding taxes) for the sewer utility service. Mr. Craig stated in his affidavit that he derived a margin on expenses by identifying a risk-free rate of 4.5% and adding a 3.0% risk factor. This method yielded Mr. Craig's recommended margin on expenses of 7.50%. Mr. Craig further stated in his affidavit that his methodology is consistent with the method presented by the Public Staff and adopted by the Commission in Docket No. W-173, Sub 14 for the Montclair Water Company.

Based upon all the evidence in the record, the Hearing Examiner concludes that a 7.50% margin on operating expenses requiring a return, as recommended by the Public Staff, is appropriate in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-13

The evidence for these findings of fact is contained in the testimony of Public Staff witnesses Morgan and McKemie.

Ms. Morgan's testimony and exhibits support her service revenue requirement of $280,303. Ms. McKemie testified she examined Sandler's customer billing records and recommended rates that will produce the service revenue requirement. Sandler has agreed to accept the recommendation of the Public Staff.

The Hearing Examiner concludes that the Public Staff recommended revenue requirement and rates are reasonable and should be approved.

The following Schedule 1 summarizes the revenues, operating expenses, taxes and depreciation in this proceeding.

SCHEDULE I
Sandler Utilities at Mill Run, LLC
Docket No. W-1130, Sub 8
Net Operating Income for a Return
For The Twelve Months Ending December 31, 2013

	Present Rates	Approved Increase	After Approved Increase
Operating Revenues:			
Service revenues	$243,552	$36,751	$280,303
Other revenues	0	0	0
Uncollectibles	(6,760)	0	(6,760)
Total operating revenues	236,792	36,751	273,543
Operating Expenses			
Salaries and wages	0	0	0
Contract labor	72,084	0	72,084
Procurement fees	10,986	0	10,986
Labor	13,850	0	13,850
Administrative & office	842	0	842
Telemetry	777	0	777
Maintenance & repairs	1,650	0	1,650
Materials	3,186	0	3,186
Equipment	526	0	526
Electric power	37,996	0	37,996
Testing	6,696	0	6,696
Chemicals	16,281	0	16,281
Sludge removal	16,758	0	16,758
Disposal expense	3,051	0	3,051
Purchased water	2,767	0	2,767
Permit fees & licenses	2,120	0	2,120
Business License Fees	327	0	327
Rate case expense	964	0	964
Insurance expense	12,243	0	12,243
Overhead expense	9,808	0	9,808

Total operating expenses	212,912	0	212,912
Depreciation expense	36,282	0	36,282
CIAC Amortization expense	0	0	0
Property taxes	0	0	0
Other taxes	952	0	952
Regulatory fee	350	55	405
Gross receipts tax	0	0	0
State income tax	0	920	920
Federal income tax	0	3,311	3,311
Total operating revenue deductions	250,496	4,286	254,782
Net operating income for return	$ (13,704)	$32,465	$18,761

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-15

The evidence of these findings of fact is contained in the testimony of Public Staff Accountant Morgan. The Hearing Examiner finds and concludes that, pursuant to HB 41, the refund of the portion of rates related to the repeal of the gross receipts tax and the reduction of the state corporate income tax should be approved, and Sandler should accomplish the refund through a billing credit to each customer of 6.19% of the amount that was billed on and after July 1, 2014, up until the date that the new rates approved herein become effective and final.

IT IS, THEREFORE, ORDERED as follows:

1. That Sandler is authorized to increase its rates and charges for sewer utility service so as to produce based on the adjusted test year level of operations, an increase in annual service revenues of $36,751.

2. That the Schedule of Rates attached as Appendix A is approved for sewer utility service rendered by Sandler. **These rates shall become effective for service rendered on and after the effective date of this Order.**

3. That the Notice to Customers attached as Appendix B shall be mailed with sufficient postage or hand delivered by Sandler to all of its customers in conjunction with the next billing statement after the date of this Order; and that Sandler shall file a copy of the attached Certificate of Service properly signed and notarized, within 10 days after providing customer notice.

4. That Sandler shall: (a) within 60 days of the effective date of this order, physically inspect every Air Vac valve pit package as to whether the pit package is subject to rain water intrusion during heaving rains; (b) within 150 days of the effective date of this order, complete renovations to reduce the rain water intrusion, including but not limited to raising and sealing pit packages subject to rain water intrusion; (c) within 180 days of the effective date of this order, file a written report with the Commission describing the completed renovations for each of the pit packages where renovations were necessary.

5. That Sandler shall within 180 days of the effective date of this order, complete renovations to the second bank of UV lights at the wastewater treatment plant to bring the UV system in compliance with North Carolina Department of Environmental Quality, Division of Water Resources regulations.

6. That Sandler shall: (a) within 60 days of the effective date of this order file with the Commission a detailed plan for the isolation of sections of the Eagle Creek sewage collection system, including the installation of isolation valves and also plans for the installation of any other necessary equipment to prevent the collection system losing its vacuum; (b) within 150 days of the effective date of this order, complete the necessary collection system isolation renovations, and installation of isolation valves, and the installation of any other necessary equipment to prevent the collection system losing its vacuum, pursuant to Sandler's detailed plan; (c) within 180 days of the effective date of this rate increase order, file a written report with the Commission describing the completed collection system isolation renovations, including the installation of necessary isolation valves, and the installation of any other necessary equipment to prevent the collection system losing its vacuum, pursuant to the detailed plan.

7. That Sandler shall refund the portion of rates related to the repeal of the gross receipts tax and the reduction of the state corporate income tax rate, through a billing credit to each customer of 6.19% of the amount billed on and after July 1, 2014, up until the date that the new rates approved in this docket go into effect.

8. That, within 15 days after issuing the refund credits, Sandler shall file with the Commission a notarized statement confirming that the billing credits have been issued as required in this order.

ISSUED BY ORDER OF THE COMMISSION.
This the __11th__ day of __December__ 2015.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

APPENDIX A
PAGE 1 OF 2

SCHEDULE OF RATES

for

SANDLER UTILITIES AT MILL RUN, LLC

for providing sewer utility service

in

EAGLE CREEK SUBDIVISION, MILL CREEK GOLF CLUB,

WATER AND SEWER – RATE INCREASE

AND MOYOCK MIDDLE SCHOOL

Currituck County, North Carolina

Monthly Sewer Rates:

Flat Rate Residential Sewer Service	$ 52.65
Mill Creek Golf Club	$365.00
Moyock Middle School	$885.00

Connection Charge:

Residential	$3,000 per residence
Commercial:	$3,000 per REU (360gpd)

Reconnection Charge:

If sewer service cut off by utility for good cause: Actual Cost [1/]

[1/] Neglect or failure to pay amounts due or otherwise comply with provisions of this tariff shall be deemed to be sufficient cause for discontinuance of service. If such discontinuance of service becomes necessary, Sandler Utilities at Mill Run, LLC, will install a valve or other device to cut off and block the sewer line. The customer will be charged the actual cost of installing the valve or device including parts and labor.

APPENDIX A
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Reconnection Charge: (continued)

Prior to disconnection, Sandler Utilities at Mill Run, LLC, will diligently try to induce the customer to pay or otherwise comply with its tariff. After such effort, Sandler Utilities at Mill Run, LLC, will give the customers written notice at least five days (excluding Sundays and holidays) prior to disconnection. Such notice will contain at a minimum a copy of this provision, the procedures to be used by Sandler Utilities at Mill Run, LLC, to install the valve or device, the estimated cost, and the procedures the customer can use to avoid the discontinuance of service.

In the event an emergency or dangerous condition is found to exist or fraudulent use of service is detected, sewer service may be cut off without notice. In such an event, notice as described will be given as soon as possible.

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be quarterly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after the billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1130, Sub 8, on this the _11th_day of __December______, 2015.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B
PAGE 1 OF 2

NOTICE TO CUSTOMERS
DOCKET NO. W-1130, SUB 8
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is hereby given that the North Carolina Utilities Commission (Commission) has issued an Order authorizing Sandler Utilities at Mill Run, LLC (Sandler), to increase sewer rates in the Eagle Creek Subdivision in Currituck County, North Carolina, by an overall rate of approximately 15.09%. The new approved rates are as follows:

Monthly Sewer Rates:

Flat Rate Residential Sewer Service	$ 52.65
Mill Creek Golf Club	$365.00
Moyock Middle School	$885.00

Gross Receipts Tax Repeal and Corporate Income Tax Reduction Refunds

The Commission ordered Sandler to refund the portion of rates related to the repeal of the gross receipts tax and the reduction of the state corporate income tax rate, through a billing credit to each customer 6.19% of the amount that was billed on and after July 1, 2014, up until the new approved rates became effective and final.

Commission Ordered Sewer System Upgrades

The Commission ordered Sandler to make the following sewer system upgrades:

Air Vac Valve Pit Packages

Sandler shall: (a) within 60 days of the effective date of this order, physically inspect every Air Vac valve pit package as to whether the pit package is subject to rain water intrusion during heaving rains; (b) within 150 days of the effective date of this order, complete renovations to reduce the rain water intrusion, including but not limited to raising and sealing pit packages subject to rain water intrusion; (c) within 180 days of the effective date of this order, file a written report with the Commission describing the completed renovations for each of the pit packages where renovations were necessary.

APPENDIX B
PAGE 2 OF 2

Wastewater Treatment Plant Disinfection System

Sandler shall within 180 days of the effective date of this order, complete renovations to the second bank of UV lights at the wastewater treatment plant to bring the UV system in compliance with North Carolina Department of Environmental Quality, Division of Water Resources regulations.

Collection System Isolations and Equipment to Prevent Loss of Vacuum

Sandler shall: (a) within 60 days of the effective date of this order file with the Commission a detailed plan for the isolation of sections of the Eagle Creek sewage collection system, including the installation of isolation valves and also plans for the installation of any other necessary equipment to prevent the collection system losing its vacuum; (b) within 150 days of the effective date of this order, complete the necessary collection system isolation renovations, and installation of isolation valves, and the installation of any other necessary equipment to prevent the collection system losing its vacuum, pursuant to Sandler's detailed plan; (c) within 180 days of the effective date of this rate increase order, file a written report with the Commission describing the completed necessary collection system isolation renovations, including the installation of isolation valves, and the installation of any other necessary equipment to prevent the collection system losing its vacuum, pursuant to the detailed plan.

This the _11th_ day of __December_, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1130, Sub 8, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2015.

By: ______________________________________
Signature

____
Name of Utility Company

The above named Applicant, _________________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-1130, Sub 8.

Witness my hand and notarial seal, this the ____ day of _____________, 2015.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ______________________________________
Date

DOCKET NO. WR-722, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Bonita Beard, 705 Lowdermilk Street, Greensboro, North Carolina 27405, Complainant v. Red Chief, LLC, Respondent	))))))))	RECOMMENDED ORDER DISMISSING COMPLAINT AND ORDERING REVISIONS TO BILLING FORMAT AND BILLING PROCEDURES

HEARD: Thursday, November 14, 2013, at 10:00 a.m., Guilford County Courthouse, Grand Jury Room 468, 201 Eugene Street, Greensboro, North Carolina 27401.

BEFORE: Corrie V. Foster, Commission Hearing Examiner

APPEARANCES:

FOR COMPLAINANT:

Bonita Beard, 705 Lowdermilk Street, Greensboro, North Carolina 27405 (pro se).

FOR THE RESPONDENT:

Daniel C. Higgins, Esq., Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27605.

BY THE HEARING EXAMINER: On March 7, 2013, Bonita Beard (Complainant) filed with the North Carolina Utilities Commission (Commission) a complaint against Red Chief, LLC (Respondent), in the above-captioned proceeding.

On March 14, 2013, the Commission issued an Order Serving Complaint.

On March 26, 2013, Respondent filed its Answer and Motion to Dismiss to the Complaint. That same day, the Commission issued an Order Serving Respondent's Answer and Motion to Dismiss.

On April 11, 2013, Complainant filed a Verification of Electric Service from Duke Energy Carolinas, LLC.

On April 12, 2013, Complainant filed her Response to Respondent's Answer and Motion to Dismiss. The Commission served both the Verification and Complainant's Response to the Answer and Motion to Dismiss on April 19, 2013.

On April 30, 2013, Respondent filed its Reply. The Commission issued an Order Serving Reply on May 9, 2013.

On May 20, 2013, Complainant filed her Response to Respondent's Reply. The Response and Order Scheduling Hearing was issued by the Commission on August 13, 2013.

On August 29, 2013, Respondent filed a Motion to Reschedule Hearing and a Notice of Appearance of Counsel. The next day, the Commission issued an Order Canceling Hearing and Holding Docket in Abeyance.

On September 18, 2013, the Commission issued an Order Scheduling Hearing. The hearing was scheduled for Thursday, October 10, 2013, at 10:00 a.m., in the Guilford County Courthouse, Greensboro, North Carolina.

On October 7, 2013, Complainant filed a letter Requesting that the hearing be rescheduled. The next day, the Commission issued an Order Canceling Hearing and Holding Docket in Abeyance.

On October 17, 2013, the Commission issued an Order Scheduling Hearing. The hearing was scheduled for November 14, 2013, in the Guilford County Courthouse, Grand Jury Room 468, 201 Eugene Street, Greensboro, North Carolina.

On October 30, 2013, Complainant filed with the Commission an Affidavit of Witness – Ms. Cierra Roberson. That same day, the Commission issued an Order Serving Affidavit.

On November 7, 2013, Respondent filed its Objection to the Submission of Affidavit into the Record.

On November 14, 2013, the hearing occurred as scheduled. Complainant appeared pro se, to testify and submit exhibits to the record in support of her claim. She also offered testimony from her witnesses Cierra Roberson and Pamela Renee Beard Hardy. Daniel Higgins, Esq., appeared in representation of Respondent. He offered the testimony of witnesses Shana Golladay, former property manager of Morehead Apartments, Stephen Shane Lively, resident service manager at Morehead Apartments, and Amy Lee Reynolds, community manager for the Morehead Apartments and submitted exhibits in support of Respondent's defense.

On December 18, 2013, Respondent filed a Motion for Extension of Time to File Proposed Orders that was granted by the Hearing Examiner on December 20, 2013.

On January 2, 2014, Respondent filed its Proposed Recommended Order Dismissing Complaint.

On January 3, 2014, Complainant filed a Motion for Extension of Time to File Proposed Order that was granted by the Hearing Examiner on January 7, 2014.

On January 31, 2014, Complainant filed Supplemental Comments and Recommended Order.

On February 10, 2014, Respondent filed its Objections to Complainant's Recommended Order to Recall.

Upon consideration of the testimony, the evidence and exhibits presented at the hearing, and the entire record in this proceeding, the Hearing Examiner makes the following:

FINDINGS OF FACT

1. The Commission issues certificates of authority to utilities to charge its tenants for water and sewer service. The Commission has regulatory authority over these certificate holders.

2. Morehead Apartments are owned by Respondent, and managed by Hawthorne Residential Partners (Hawthorne).

3. ISTA of North Carolina (ISTA) is the billing agent for Respondent. As the billing agent, ISTA is responsible for preparing and sending out billing statements for tenants including Complainant in the Morehead Apartments in Guilford County, North Carolina.

4. N.C.U.C. Docket No. WR-722, Sub 0, (March 12, 2008) (Respondent is granted authority by the Commission to charge a total Administrative fee of $14.33 (consisting of $3.15 for Applicant's water reading, billing, collecting costs plus a pass through of Greensboro's $11.18 base charge for water and sewer service) and approved rates of $2.87 per 1,000 gallons for water and $3.61 per 1,000 gallons for sewer).

5. In addition to the Commission's regulated charges, tenants at Morehead Apartments are also expected to pay a $2.76 stormwater fee and an $8.25 trash fee. These fees are not regulated by the Commission.

6. Bonita Beard lived in a two bedroom, $1^1/_2$ bath apartment at 5604-H, W. Market Street, Greensboro, North Carolina 27401, from November 17, 2009, until August 2, 2012.

7. Respondent did not bill Complainant for her initial water use in November 2009. Her first bill was for service beginning December 28, 2009, and ending March 28, 2010. At the beginning of her billing period, the meter started at 3275160. The bill was sent to her almost five months later in May 2010. During that billing period, Complainant's meter registered a total of 8,880 gallons of water used. The bill was one hundred twenty five dollars and forty cents ($125.40).

8. On May 17, 2010, Complainant called the Public Staff – North Carolina Utilities Commission (Public Staff), with concerns about her water bill.

9. Respondent applied Complainant's Section 8 rental balance of one hundred sixty two dollars and eighty one cents ($162.81) to her first water bill of one hundred twenty five dollars

and forty cents ($125.40). This left her a credit of thirty seven dollars and forty one cents ($37.41) on her account.

10. ISTA technicians conduct on-site visits to the Morehead Apartments quarterly. During these visits, the technicians check on water meters and investigate tenant complaints. ISTA's policy is to have its' technicians accompanied by a property's service manager or other service personnel when it enters a tenant's apartment to investigate a water complaint.

11. Due to concerns voiced by Complainant about her water bills, Hawthorne completed five or six work orders to have Complainant's water meter checked. Stephen Shane Lively, resident service manager at Morehead Apartments personally visited Complainant's apartment three times with the ISTA technician to investigate her water complaints. On one of these visits, the ISTA technician performed a float test using 10 gallons of water. The meter was found to be functioning properly.

12. At the end of August 2011, the ISTA technician replaced the meter in Complainant's apartment. ISTA technician's routinely performed maintenance on the meters by changing batteries in the transmitters of the meter and even switching out entire meters. Respondent believed that replacing the meter would assuage Complainant's concerns with her water bills. After the meter was replaced, the ISTA technician performed a float test using 10 gallons of water. The new meter was found to be functioning properly. At the beginning of its reading cycle, the meter showed 453193.

13. <u>N.C.U.C. Docket No. WR-722, Sub 1</u>, (June 27, 2011) (Respondent is granted Tariff Revision by the Commission can now charge an Administrative fee of $14.33 (consisting of $3.15 for Applicant's meter reading, billing, and collecting costs plus a pass through of Greensboro's $11.18 base charge for water and sewer) and approved rates of $3.07 per 1,000 gallons for water and $3.81 per 1,000 gallons for sewer).

14. Complainant averaged usage of 3,296 gallons a month in 2010, 3,778 gallons during the first six months of 2011, 3,365 gallons a month during the second six months of 2011 and 2,939 gallons during the first seven months of 2012.

15. Complainant executed a total of three residential lease agreements with Respondent. The first lease was from November 17, 2009, until October 31, 2010. Section 1(c) of the lease clearly states that all water and sewer services will be sub-metered and that the water/sewer utility charges would be paid by Complainant. This information was acknowledged with Complainant's initials. The second lease was from November 1, 2010, to October 31, 2011. The third lease agreement was from November 1, 2011, to October 31, 2012.

16. Respondent violated Commission Rule 18-7(f) when it neglected to provide Complainant with a copy of its rates approved by the Commission at the time she signed her lease agreements.

17. On March 13, 2012, the housing manager of Morehead Apartments sent Complainant written notification that Respondent would no longer accept Section 8 vouchers as of May 31, 2012.

18. Complainant was sent her final water bill in August 2012 for the period of May 29, 2012, to August 2, 2012. The bill totaled ninety two dollars and twenty six cents ($92.26), but the charges were not itemized to show each month's usage. There were also accumulated fees applied to the billing period.

19. Because the Complainant could not get a clear answer from Respondent about her water bill, she filed a complaint with the Commission on March 7, 2013.

20. Respondent is properly before the Commission pursuant to Commission Rule R1-4.

21. Respondent is in violation of Commission Rule by failing to post its approved rates by the Commission in public view in its business office during operating hours.

ARGUMENTS

Complainant asserts that the water meter in her apartment malfunctioned. As a result of the meter problem, she claims that Respondent has been estimating her water bills since she moved into the apartment. She seeks an adjustment of the charges she has paid to Respondent from November 2009 until August 2011.

Respondent, on the other hand, contends that Complainant's water usage was not estimated but is based on her metered usage. Respondent further asserts that Complainant's meter had been tested and found to be functioning properly. It is Respondent's contention that Complainant is not entitled to an adjustment of rates or any other relief.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

North Carolina General Statute (G.S.) 62-75, in relevant part, indicates that the burden of proof in complaint proceedings is upon the Complainant to show that the action of the utility with regard to its rates, services, classification, rules, regulations or practice is unjust and unreasonable. The Complainant may meet this burden of proof with the submission of evidence, including testimony and exhibits that would be admissible in a court of law, in support of the complaint at an evidentiary hearing.

After reviewing the law, Commission Rules, testimony of the witnesses and the exhibits submitted to the record, the Hearing Examiner finds and concludes that Complainant has failed to meet her burden of proof in this complaint proceeding. The Hearing Examiner further finds and concludes that Respondent's billing format is misleading and should be revised. Finally, the Hearing Examiner finds and concludes that Respondent violated Commission Rules by not making its approved rates available to Complainant by providing her with a copy of the rates when she signed the lease and posting the rates in public view in its business office.

Complainant believes that her water service was estimated because of two reasons. The first reason is that Complainant states that an ISTA technician came to her residence in August of 2011 and replaced the water meter. During this visit, she claims that he stated that the meter had been broken for a while and that he didn't know how Respondent was registering her bills. She claims that he suggested that her bills had been estimated. The second reason she believes her bills were estimated is that she claims that she was told by her neighbor Sharon Clark of Apartment 5604-G that her [Ms. Clark's] water bill's never reached higher than $40.00 per month. Considering that Complainant lived in a smaller apartment than her neighbor, she assumed that her bills should be just as small as $40.00.

The record shows that Complainant voiced her concerns about her bill from the beginning. After she received her first bill, she asked several employees at Morehead Apartments to explain to her how she was being billed for service. Unfortunately, no one was able to adequately answer her questions. Complainant's inquiries were so frequent that it caused the management company to submit several work orders to have her water usage investigated. This investigation included having the meter checked. In August 2011, the ISTA technician and the service manager at Morehead Apartments both visited Complainant's residence to address her concerns about her water. At that time, the ISTA technician changed Complainant's meter. Respondent indicates that this was not an indication that something was wrong with the meter. Instead, Respondent states that this was normal maintenance on the part of ISTA considering the number of work orders that were received regarding Complainant.

It was during this visit, that Complainant testified she heard the ISTA technician say the meter was not registering. Complainant's witness testified that she heard the same statement. However, this was disputed by the service manager at Morehead Apartments who testified that he did not hear any such statement. Even if the Hearing Examiner believed the Complainant, the statement of the ISTA technician by itself is insufficient to find that Complainant's bills were incorrect. In fact, there is no corroborating evidence that shows that Complainant's bills were estimated and thus incorrect.

The Hearing Examiner takes judicial notice that Respondent was granted authority to provide water and sewer service to Morehead Apartments in Guilford County, North Carolina, beginning on March 12, 2006.[1] The same rates were in effect for most of the period that Complainant lived in her apartment. Respondent, however, was approved for a tariff revision by the Commission on June 27, 2011.[2]

The Hearing Examiner has reviewed Complainant's billing statements. These billing statements were introduced into the record as Respondent's exhibits #4 - #32 and cover Complainant's water and sewer service from December 28, 2009, to August 2, 2012. Each billing statement identifies Complainant's name, the service address, account number, service dates, and the number of days between billing cycles. Additionally, the beginning meter readings and the ending meter readings as well as the total gallons used are included on each statement.

[1] N.C.U.C. Docket No. WR-722, Sub 0, (March 12, 2008) (Respondent is granted authority by the Commission to charge a total Administrative fee of $14.33 (consisting of $3.15 for Applicant's water reading, billing, collecting costs plus a pass through of Greensboro's $11.18 base charge for water and sewer service) and approved rates of $2.87 per 1,000 gallons for water and $3.61 per 1,000 gallons for sewer).

[2] N.C.U.C. Docket No. WR-722, Sub 1, (June 27, 2011) (Respondent is granted Tariff Revision to rates can now charge an Administrative fee of $14.33 (consisting of $3.15 for Applicant's meter reading, billing, and collecting costs plus a pass through of Greensboro's $11.18 base charge for water and sewer) and approved rates of $3.07 per 1,000 gallons for water and $3.81 per 1,000 gallons for sewer).

The billing statements clearly show that in addition to her actual water and sewer use, Complainant was responsible for several base charges related to the delivery of her water service. The following base charges were applied to Complainant's monthly bills: base water/sewer charge ($11.18); Admin/service charge ($3.15); stormwater ($2.76)[1]; and trash fee charge ($8.25)[2]. These base charges total $25.34 and were assessed to Complainant's account even before her actual water and sewer usages were calculated.

According to the Hearing Examiner's calculations, Complainant used on average approximately 3,296 gallons of water a month in year 2010. This calculates to an average charge of about $9.46 for water and $11.90 for sewer service a month. During the first six months of 2011, Complainant averaged about 3,778 gallons a month which breaks down to an average charge of $10.84 for water and $13.64 for sewer service. Respondent was granted a rate increase from the Commission on June 27, 2011. The rate increase impacted Complainant's averages for the remaining half of the year. Therefore, during the remaining six months of the year, Complainant used about 3,365 gallons of water a month. This calculated to an average charge of $10.33 for water and $12.82 for sewer a month. In 2012, Complainant averaged usage of 2,939 gallons a month over a seven month period. This breaks down to an average charge of $9.02 for water and $11.20 for sewer service per month.

The Hearing Examiner understands that Complainant questions the validity of her water bills from the beginning of her occupancy in November 2009 until the meter was changed in August 2011. However, the usage totals printed in her monthly billing statements before August 2011 do not appear unreasonable compared to the totals that were recorded on her meter during the latter part of 2011 and into 2012. In developing these calculations, the Hearing Examiner reviewed the meter readings in Complainant's 2010 statements leading up to those in 2011 and even after the meter was changed. When Complainant's meter was changed, it was apparent throughout the statements after September 29, 2011, because the meter began to register a new cycle.[3] Overall, the total gallon readings on the new meter were consistent in range with the totals in 2010 through the early part of 2011 from the old meter.

The Hearing Examiner would find it difficult for the Respondent to estimate Complainant's usage for an eighteen month period without there being some indication in the billing statements. In this case, there are no apparent abnormalities in the historical billing that indicates or would support a finding that the numbers are unreasonable. In other words, there is nothing in the billing data that suggests that the recorded amounts from the meter were estimated and not actual readings. After reviewing Complainant's bills, the Hearing Examiner finds that the totals from her meter are not inconsistent with her recorded usage.

As for the Complainant's statement regarding her neighbor's bills, the Hearing Examiner is not in a position to definitively assess Complainant's neighbor's monthly usage. At this point, Complainant's belief that she should have lower bills than her neighbor is based on a hearsay

[1] Charge is not regulated by the N.C. Utilities Commission.

[2] Id.

[3] Complainant's billing statement of water usage from 9/29/2011, to 10/29/2011, starts with a meter reading of 453193 signifying the beginning of the new meter. The ending cycle of the old meter reading was 3347810.

statement about her neighbor's bills. Complainant did not submit copies of her neighbor's bills to allow for a valid comparison of their monthly usage or to support her assertion that she was somehow being billed differently than other tenants in the building. The Hearing Examiner finds and concludes that Complainant's mere statement that she uses less water than her neighbor without submitting corroborating documentation is insufficient evidence.

In reviewing Complainant's billing statements, the Hearing Examiner has determined that the statements produced by Respondent are misleading. Although the charges on the bill are individually listed, there is no distinct recognition of the charges as being regulated or unregulated by the Commission. Unfortunately, this billing format gives the impression that all of the charges listed on the bill are approved by the Commission. This is not accurate. The Commission has no jurisdiction over stormwater and trash service related fees.[1] The Hearing Examiner believes that these particular unregulated charges should be either removed from among the list of regulated charges and placed in a separate section of the bill or highlighted to distinguish them from the charges approved by the Commission. A change in the present billing format would minimize any confusion with regard to the actual regulated charges on the bill. Regulated charges that the charges that the Commission can address in a complaint proceeding.

The Hearing Examiner is of the opinion that Respondent has incited suspicion with Complainant by its actions and its billing practices. After hearing testimony from Respondent's property manager and reviewing certain billing statements, the Hearing Examiner understands why the Complainant was concerned when she received her bills from Respondent. While receiving testimony from Respondent's witness Ms. Golladay, it became apparent to the Hearing Examiner that Complainant might not fully understand how she was being billed for water and sewer service. This was initially not Complainant's fault but that of the Respondent. The Hearing Examiner specifically inquired as to whether Ms. Golladay was familiar with the Commission rules for billing? Ms. Golladay answered in the affirmative that she was. The Hearing Examiner then asked the following:

Hearing Officer Foster: And you understand that Red Chief operates as a water – what we call a water reseller?

Ms. Golladay: Yes, that's correct.

Hearing Officer Foster: Now, in terms of your office, do you have the rates posted?

Ms. Golladay: No.

Hearing Officer Foster: So, they're available to consumers?

Ms. Golladay: No.

Hearing Officer Foster: No?

[1] Commission Rule R18-2(g), states in pertinent part, that Supplier's base charge cannot include charges not related to the provision of utility service, such as stormwater fees, trash collection, or property taxes.

Ms. Golladay: No.

Hearing Officer Foster: No.

As a holder of a certificate to provide water and sewer service, Respondent must comply with the various provisions of Chapter 62 and the Commission's Rules. Based on Ms. Golladay's responses to the Hearing Examiner's questions, it is clear that Respondent is in violation of Commission Rule R18-7(f). This rule requires that Respondent provide to each customer a copy of rates, rules and regulations at the time the lease agreement is signed and to maintain, in public view, a copy of the rates in Respondent's business office. Respondent has not submitted evidence to the record that it provided Complainant information on its water rates. This failure on the part of Respondent to share information about its approved rates is unacceptable. Complainant executed three lease agreements with Respondent, at no time was she given a copy of the rates that were approved by the Commission. It is the Hearing Examiner's opinion that had Respondent complied with the Commission's rule, it may have mitigated some of the confusion surrounding Complainant's billing statements. By that time, Complainant would have a copy of the rates, and would have been in a better position to understand how she was being billed for water and sewer service.

It is apparent to the Hearing Examiner that this confusion with Respondent's billing practices began when Complainant received her first bill and did not end even after she received her final bill. In reviewing these specific two billing statements, the Hearing Examiner noticed several problems with them. First, Complainant moved into her apartment on November 17, 2009, however, she did not receive her first water bill until almost five months after. Respondent asserts that it was setting Complainant up in its billing system and as a concession it did not bill her for water her first month in the apartment. The first bill covered service from December 28, 2009, until March 28, 2010. It is commendable that Respondent did not bill her for water during the initial month of her residency. However, that does not mitigate the fact that Complainant was not sent the bill until almost five months after she moved into the apartment. According to Commission Rules, Complainant is entitled to receive her bills on a monthly basis.[1] Based on its delayed billing, it was evident that Respondent did not comply with the Commission's guideline that requires bills be sent on a monthly basis. The Hearing Examiner understands that it would take some time to initially set-up Complainant's utility account. However, it does not appear that Respondent used its best efforts to forward Complainant her bill in a timely manner. Second, the initial bill that was sent to Complainant was not itemized. In other words, Complainant's monthly usage was not clearly indicated on the bill. Instead, the bill contained a total usage of 8,800 gallons for the period spanning December 28, 2009, through March 28, 2010. Third, Complainant's was assessed several months of water and sewer base charges for that extended billing period. These charges were not expressly detailed to provide Complainant clear understanding of why they were being applied to her account.

Respondent repeated the same errors on Complainant's final bill that was sent to her in August of 2012. This bill covered Complainant's water use from May 29, 2012, through August 2, 2012, and totaled ninety two dollars and twenty six cents ($92.26). The bill did not show her itemized monthly water use but did provide an accumulated total gallon amount spanning over

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[1] Commission Rules R7-23(c) & R18-7(c) state that bills should be rendered at least monthly.

two months. The bill was for total usage of 6,630 gallons of water. Finally, there were several accumulated base charges that were not specifically detailed in a form that Complainant could readily understand them. Overall, Respondent's billing format was inadequate to provide the Complainant with a clear understanding of the monthly amount of water usage and the accumulated charges applied to the bill.

The record shows that Complainant was not denied nor had difficulty with obtaining her water and sewer service from Respondent during her residency at Morehead Apartments. The only issue that she raises resolves around her suspicion that her utility service was estimated by Respondent. Unfortunately, Complainant was not able to provide sufficient evidence to support such a finding. The Commission has long since stated that consumers should pay for the utility service that they receive. In this case, Complainant received the service that was provided by Respondent and she paid for it. Although Complainant was not provided a copy of the rates when she signed her lease in 2009, this does not mean that she is entitled to an adjustment of her rates. Complainant was advised, as evidenced by her initials on the lease, that the service was not free and that she would have to pay. Therefore, there is no basis to award Complainant the relief that she has requested.

Given the findings and conclusions identified in this proceeding, the Hearing Examiner finds good cause exists to recommend that the Complaint be dismissed. The Hearing Examiner further finds good cause exists to recommend that Respondent immediately take corrective steps to comply with North Carolina Law and Commission Rules as they relate to its billing for water and sewer service at the Morehead Apartment building. First, that Respondent posts a copy of its approved rates from the Commission in public view in its business office so that it is readily available to the tenants during normal operating hours. Second, that Respondent begins to provide a copy of its approved rates to new tenants as they sign their lease agreements. Third, that Respondent amend its billing statements by either relocating the unregulated charges to another section of the bill or clearly noting which charges are regulated by the Commission and those that are not, so to avoid any confusion by the tenant. Lastly, that Respondent sends its tenants their billing statements at least monthly as required by Commission Rule.

The Hearing Examiner understands that Respondent has been given recommendations that are expected to bring Respondent in compliance with North Carolina Law and Commission Rules. These recommendations include but are not limited to providing its tenants with additional notice of its approved rates and making several amendments or revisions to its billing statements to clarify its accumulated billing of base charges and utility service that has not been itemized. If Respondent determines that it is unable or needs additional direction in order to adhere to this Order, the Hearing Examiner would encourage Respondent to seek the guidance and assistance of the Public Staff - North Carolina Utilities Commission (Public Staff). The Public Staff represents the using and consuming public in matters before the Commission. This agency may be instrumental in working with Respondent to ensure that it minimizes any barriers of understanding with tenants and their billing statements. This will be vital in order to avoid issues such as the one that arose in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the dispute filed by Complainant in this docket is hereby dismissed.

2. That Respondent immediately take the following corrective steps to comply with North Carolina Law and Commission Rules as they relate to its billing for water and sewer service at Morehead Apartments:

(a) Respondent posts a copy of its approved rates from the Commission in public view in its business office so that it is readily accessible to tenants during normal operating hours;

(b) Respondent provides a copy of its approved rates to new tenants as they sign their lease agreements;

(c) Respondent amend its billing statements by either relocating the unregulated charges to another section of the bill or clearly noting which charges are regulated by the Commission and those that are not so to avoid any confusion by the tenant; and

(d) Respondent sends its tenants their billing statements at least monthly as required by Commission Rule.

3. Respondent shall file notification with the Commission including a copy of its amended billing statement to demonstrate that it has complied with the recommendations provided above. This amended billing statement shall be filed with the Commission no more than thirty days after the issuance of this Order.

4. That this Order shall be served on Complainant by United States certified mail, return receipt requested and on Respondent by electronic mail, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of January, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. WR-722, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Bonita Beard, 705 Lowdermilk Street, Greensboro, North Carolina 27405, Complainant v. Red Chief, LLC, Respondent	))))))))	ERRATA ORDER

BY THE HEARING EXAMINER: On January 27, 2015, the Hearing Examiner issued a Recommended Order Dismissing Complaint and Ordering Revisions to Billing Format and Billing Procedures in the above-captioned proceeding. It has come to the attention of the Hearing Examiner that there is an inadvertent error on page 7 of the Order. In particular, at the end of the first sentence in the second paragraph the Hearing Examiner wrote the date – March 12, 2006. The date, however, should read March 12, 2008.

The Hearing Examiner finds good cause exists to correct the date in the Recommended Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the first sentence of the second paragraph on page 7 should read

> The Hearing Examiner takes judicial notice that Respondent was granted authority to provide water and sewer service to Morehead Apartments in Guilford County, North Carolina, beginning on March 12, 2008.[1]

2. That, except as amended herein, the Recommended Order of January 27, 2015, shall remain unchanged.

3. That this Order will be served on Complainant by United States certified mail, return receipt requested and on Respondent by electronic mail, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of January, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. WR-722, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Bonita Beard, 705 Lowdermilk Street, Greensboro, North Carolina 27405, Complainant	)	ORDER RULING ON EXCEPTIONS AND ADOPTING RECOMMENDED ORDER
v.	)	
Red Chief, LLC, Respondent	)	

BY THE COMMISSION: On March 7, 2013, Bonita Beard (Complainant or Ms. Beard) filed a complaint with the Commission against Red Chief, LLC (Respondent or Company). In her Complaint, Complainant alleged that the water meter in her apartment had malfunctioned, that this malfunction continued from November 2009 until August 2012, that, as a result of the malfunction, Respondent estimated[1] her water bills during her tenancy, and that she was entitled to an adjustment of the charges that she paid to Respondent from November 2009 until August 2012.

In its response, the Company contended that Complainant's water usage was determined based on her metered usage, that the Complainant's meter had been tested and found to be functioning properly, that Complainant was, therefore, properly billed and was not entitled to an adjustment of rates or any other relief.

On November 14, 2013, the hearing occurred as scheduled. Complainant appeared pro se,[2] testified, and submitted exhibits to the record in support of her claim. She also offered testimony from her witnesses Cierra Roberson and Pamela Renee Beard Hardy. Daniel Higgins, Esq., appeared in representation of Respondent. He offered the testimony of witnesses Shana Golladay, former property manager of Morehead Apartments; Stephen Shane Lively, resident service manager at

[1] Commission Rule R7-25(f) provides: "Nonregistering Meter.-If a meter is found not to register for any period, the utility shall estimate the consumption, based on a like period of similar use." It is unclear if Complainant was aware of this Rule when she filed the Complaint or when she presented her case during the hearing. However, in the Exceptions, Complainant clearly indicates that she is aware that the Company is allowed to bill her based on her estimated usage if the meter was not registering during her tenancy. Because Complainant "totally disagrees with this rule," she insists that she is entitled to monetary relief simply because the Respondent estimated her bill. Exceptions p. 18; see also Exceptions p. 20, second full paragraph.

[2] In post hearing filings and again in Exceptions, Ms. Beard complains that she was disadvantaged at the hearing because Hearing Examiner Foster advised her prior to the hearing that she could pursue her Complaint without the assistance of an attorney. She now recognizes that her failure to secure counsel might not have been a wise decision. While the Commission cannot and will not comment on the wisdom of her decision in this regard, the Commission will note that we generally give a pro se litigant considerable leeway in presentations before and filings with the Commission. After reviewing the entire record in this docket, the Commission is confident that the Complainant was given considerable leeway in this matter and that the arguments that she made and the positions that she advocated were fully and fairly considered by the Hearing Examiner and the Commission. Thus, she was not disadvantaged by proceeding pro se.

Morehead Apartments; and Amy Lee Reynolds, community manager for the Morehead Apartments, and submitted exhibits in support of Respondent's defense.

On January 27, 2015, Hearing Examiner Corrie V. Foster issued a Recommended Order Dismissing Complaint and Ordering Revisions to Billing Format and Billing Procedures (Recommended Order). In the Recommended Order, Hearing Examiner Foster stated:

> North Carolina General Statute (G.S.) 62-75, in relevant part, indicates that the burden of proof in complaint proceedings is upon the Complainant to show that the action of the utility with regard to its rates, services, classification, rules, regulations or practice is unjust and unreasonable. The Complainant may meet this burden of proof with the submission of evidence, including testimony and exhibits that would be admissible in a court of law, in support of the complaint at an evidentiary hearing.
>
> After reviewing the law, Commission Rules, testimony of the witnesses and the exhibits submitted to the record, the Hearing Examiner finds and concludes that Complainant has failed to meet her burden of proof in this complaint proceeding. The Hearing Examiner further finds and concludes that Respondent's billing format is misleading and should be revised. Finally, the Hearing Examiner finds and concludes that Respondent violated Commission Rules by not making its approved rates available to Complainant by providing her with a copy of the rates when she signed the lease and posting the rates in public view in its business office.

Hearing Examiner Foster thereafter ordered:

> 1. That the dispute filed by Complainant in this docket is hereby dismissed.
>
> 2. That Respondent immediately take the following corrective steps to comply with North Carolina Law and Commission Rules as they relate to its billing for water and sewer service at Morehead Apartments:
>
> (a) Respondent posts a copy of its approved rates from the Commission in public view in its business office so that it is readily accessible to tenants during normal operating hours;
>
> (b) Respondent provides a copy of its approved rates to new tenants as they sign their lease agreements;
>
> (c) Respondent amend its billing statements by either relocating the unregulated charges to another section of the bill or clearly noting which charges are regulated by the Commission and those that are not so to avoid any confusion by the tenant; and

(d) Respondent sends its tenants their billing statements at least monthly as required by Commission Rule.

3. Respondent shall file notification with the Commission including a copy of its amended billing statement to demonstrate that it has complied with the recommendations provided above. This amended billing statement shall be filed with the Commission no more than thirty days after the issuance of this Order.

4. That this Order shall be served on Complainant by United States certified mail, return receipt requested and on Respondent by electronic mail, delivery confirmation requested.

On March 12, 2015, Complainant filed Exceptions to Deny Recommended Order to Dismiss. (Exceptions) In her Exceptions, the Complainant requested that her Complaint not be dismissed and that the Respondent be ordered to provide her with appropriate and just compensation for the wrongful, fraudulent and unethical charges and inconvenience that she incurred as a result of the improper billing that resulted from the malfunctioning water meter. Complainant did not request oral argument in order to be heard on the exceptions. Nor did Complainant challenge the provisions in the second ordering paragraph of the Recommended Order which required the Company to take certain actions to comply with Commission policies and procedures in the future.

On January 22, 2015, Respondent filed its Response to the Exceptions (Response). In the Response, the Company contended that the Recommended Order is well supported by the record and that the Commission should overrule all exceptions asserted by Complainant and should adopt the Recommended Order. In addition, the Company noted that it had complied with the requirements set forth in the second ordering paragraph of the Recommended Order.

DISCUSSION

As noted above, on January 27, 2015, Hearing Examiner Foster issued a Recommended Order Dismissing Complaint. On March 12, 2015, Complainant filed her exceptions to the Recommended Order to challenge the recommendation that her Complaint be dismissed. At the outset, the Commission notes that Complainant's filing totaled 93 pages, 28 of which included text and argument. The remaining 65 pages consisted of previously filed documents that were considered during the hearing and previously excluded evidence and argument which were not. In her discussion, Complainant contends that Hearing Examiner Foster erroneously concluded that her Complaint should be dismissed. She, therefore, requests that the Commission reverse his decision dismissing her complaint and denying her just compensation.

In its Response, the Company states that "[t]he Recommended Order is well supported by the record, and the Commission should overrule all exceptions asserted by Ms. Beard and adopt the Recommended Order." Response pp.1-2. In support of its recommendation that the Commission overrule the exceptions and sustain the Recommended Order, the Company explained that Complainant's exceptions are a "rambling diatribe" which is "really just a rehash of her testimony at the hearing and the arguments that she has made in prior filings (which arguments the Hearing Examiner rejected almost entirely), and various papers and exhibits [which] she has previously submitted." Response p. 2. Moreover, the Company observed that "Ms. Beard did not take exception to specific facets of the Recommended Order, instead she takes exception to the entire Recommended Order and regurgitates the same arguments she presented in her complaint, at the hearing and in her post-hearing filings." Response p. 2. For those reasons and many more cited in its Response, the Company respectfully requested that the Commission overrule Complainant's exceptions, sustain the Hearing Examiner's Recommended Order dismissing the Complaint, and close the matter. For the reasons set forth by the Company in its Response, the Commission agrees that the Recommended Order is well supported by the record and that the exceptions raised by the Complainant should be overruled. Additionally, the Commission finds and so concludes that the Recommended Order should be sustained and the exceptions overruled for the following reasons.

In the Notice to Parties, a copy which the Chief Clerk provides to each party along with the Recommended Order, the Commission instructs a party that files exceptions that:

> [e]ach exception must be numbered and clearly and specifically stated in one paragraph without argument. The grounds for each exception must be stated in one or more paragraphs, immediately following the statement of the exception, and may include any argument, explanation, or citations the party filing same desires to make. (Emphasis in the original.)

This specificity is required because G.S. 62-78 mandates that, when a challenge is made to a specific finding, conclusion or exception in a recommended order, the Commission must consider the specific challenge and that "[t]he [Commission must] show the ruling upon each requested finding and conclusion or exception." G.S. 62-78(b) (emphasis added).

Despite these instructions, the record reveals that Complainant did not number or identify any specific finding, conclusion or exception to the Recommended Order. Nor did she clearly and specifically set forth her exceptions to the Recommended Order in one paragraph. Instead, Complainant's filing totaled 93 pages, 28 of which included text and argument which, as Respondent states in its filing, is nothing more than a rehash of her testimony and argument during the hearing. Thus, Ms. Beard is not complaining about any specific error that the Hearing Examiner made. Rather, by her submission she is contending that the Hearing Examiner's ultimate conclusion that her Complaint should be dismissed because she failed to meet her burden of proving that she should be reimbursed for the money that she paid for services rendered to her by Respondent between November 2009 and August 2012 is erroneous. Therefore, the Commission will treat her filing as a single exception with accompanying argument and supporting documents and will analyze it accordingly.

Complainant's theory that allows her to recover is based upon her belief that her meter was broken sometime prior to her move-in December 2009 and was not replaced until August or September 2011. Her evidence to support the contention was then and is now that: (1) there had been a fire in the apartment that tripped the circuit box prior to her move-in in January 2009 and ["more than likely knocked out the transmitter/meter"[1]]; (2) after her meter was replaced in August or September 2011, the maintenance person/technician told her that her meter had been broken for a while and that he did not know how the Company was registering her usage; and (3) her bills were higher than her neighbor's bills. Because she believes these three matters to be true, Complainant asserts that each bill that she received for services rendered during her tenancy was estimated and incorrect and she is, therefore, entitled to be reimbursed for the <u>total</u> amount of money that she paid for services. Complainant asserts the latter even though it is beyond dispute that she received and used at least some portion of the services for which she was billed. Further, Complainant contends that this is competent, material evidence that would merit the relief that she seeks.

In the Recommended Order, the Hearing Examiner weighed the evidence provided by Complainant that her meter was malfunctioning prior to August 2011 and the evidence provided by the Company that it was not. After fully considering the credibility and demeanor of the witnesses, the testimony that they had given,[2] the exhibits and documents filed by the parties and the inferences to be drawn from the evidence, the Hearing Examiner made the following findings of fact:

> 10. ISTA technicians conduct on-site visits to the Morehead Apartments quarterly. During these visits, the technicians check on water meters and investigate tenant complaints. ISTA's policy is to have its technicians accompanied by a property's service manager or other service personnel when it enters a tenant's apartment to investigate a water complaint.
>
> 11. Due to concerns voiced by Complainant about her water bills, Hawthorne completed five or six work orders to have Complainant's water meter checked. Stephen Shane Lively, resident service manager at Morehead Apartments personally visited Complainant's apartment three times with the ISTA technician to investigate her water complaints. On one of these visits, the ISTA technician performed a float test using 10 gallons of water. The meter was found to be functioning properly.

[1] Exceptions, Finding of Facts No. 1, p 1.

[2] During the hearing, the Company's witnesses gave direct testimony to support each of the findings cited above. Complainant, on the other hand, presented no direct evidence to contradict the substance of the Company's evidence. Instead, her evidence consisted of hearsay statements, speculation and inferences that she drew based upon her speculation.

> 12. At the end of August 2011, the ISTA technician replaced the meter in Complainant's apartment. ISTA technicians routinely performed maintenance on the meters by changing batteries in the transmitters of the meter and even switching out entire meters. Respondent believed that replacing the meter would assuage Complainant's concerns with her water bills. After the meter was replaced, the ISTA technician performed a float test using 10 gallons of water. The new meter was found to be functioning properly. At the beginning of its reading cycle, the meter showed 453193.

The substance of these findings is that Respondent had Complainant's meter/transmitter checked on numerous occasions after she moved in as a matter of routine maintenance and/or because Ms. Beard complained about her high water bill; that as a matter of routine maintenance the batteries on the transmitter were changed; that there was no evidence that the current or past meters and/or the transmitters had malfunctioned (T. p. 121); and, that Complainant's original water meter was replaced in August/September 2011 solely to assuage Complainant's concern that her current meter was not functioning properly (T. p. 120). Based upon these findings of fact and his review of the actual bills provided by Complainant, the Hearing Examiner concluded that the usage figures included in the Complainant's bills were not estimates,[1] but were derived from the actual amounts of water used by Complainant. Further, the Hearing Examiner determined that the evidence presented by Complainant was insufficient to contradict those findings and that her complaint should, therefore, be dismissed.

Under the circumstances herein described, the role of the Commission <u>in this case</u> is to review the Recommended Order to determine if the findings and/or conclusions of the Hearing Examiner are supported by a preponderance of the evidence. Or, stated somewhat differently, the role of the Commission <u>in this case</u> is to sustain the findings and/or conclusions in the Recommended Order unless the findings and/or conclusions are clearly contrary to the preponderance of the admissible evidence[2] giving due regard of the opportunity of the Hearing Examiner to evaluate the credibility of the witnesses.

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[1] In the Recommended Order, on pp.7-8, the Hearing Examiner did a detailed examination of each of Complainant's water bills from the beginnings of Complainant's occupancy in the apartments to her move-out. His analysis included the period before the meter was changed and the period after the meter was changed. He examined the meter readings and usages before and after the change in meter. He found that the total gallon readings on the new meter were consistent in range with the totals and 2010 and 2011. He found nothing in the billings to suggest that the recorded amounts on the meter were estimated and not actual readings.

[2] During the hearing, and again in the Exceptions, Complainant repeatedly refers to things that were said during settlement/mediation negotiations and things that were said by the Public Staff outside of the hearing to support her contentions. During the hearing, the Hearing Examiner sustained objections made by Respondent that settlement discussions and hearsay are inadmissible. The Hearing Examiner did not consider these matters in making his decision for those reasons. Respondent has again objected to the inclusion of these forbidden matters in the Commission's review of Complainant's exception. Because those matters are statutorily inadmissible, the Commission cannot and will not give Complainant's statements about settlement discussions and statements made by the Public Staff any consideration when making its decision in this matter.

After carefully reviewing the transcript, the Exceptions, the Response, Complainant's argument and the entire record, the Commission finds and so concludes that Respondent's evidence provided during the hearing was and is fully supportive of the Hearing Examiner's findings that Complainant's meters and transmitters did not malfunction, that the meters were replaced solely to assuage Complainant's concerns and that the usage figures included in Complainant's bills were derived from the actual amounts of water used by Complainant and not estimates. Further, the Commission finds and so concludes that the Hearing Examiner correctly determined from the evidence presented that it would be difficult for Respondent to estimate Complainant's usage for eighteen months without there being some indication in the billing statements, that the Hearing Examiner could not assess Complainant's neighbors water usage and compare it to Complainant's water usage because Complainant failed to submit any of the neighbor's bills for comparison purposes, and that the usage totals printed on Complainant's bills before the meter was changed in August 2011 do not appear to be unreasonable compared to the totals that were recorded on her meter during the latter part of 2011 and 2012.

Finally, the Commission concurs with the Hearing Examiner's determination that the aforementioned findings and conclusions could not be overcome by Complainant's unproven assertions that a fire in the apartment on January 24, 2009, tripped the circuit box and more than likely knocked out the transmitter box, that her bills were estimated by Respondent as a result and that there was no way that she, as a single occupant of the apartment, could have used the amount of water that was reflected in her bills. As a result, the Commission is, therefore, compelled to sustain the ultimate conclusion reached by the Hearing Examiner that Ms. Beard's Complaint should be dismissed because she "failed to meet her burden of proof in this complaint proceeding." Recommended Order, p. 6.

For the aforementioned reasons, Complainant's exception is overruled and the Recommended Order is hereby adopted as the Order of the Commission.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _20th_ day of May, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. WR-1163, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Carl Mascott, 608 Appelton Drive, Apt. F, Raleigh, North Carolina 27606, Complainant v. Sumare, L.P., Respondent	ORDER RULING ON EXCEPTIONS

BY THE COMMISSION: On December 5, 2014, Hearing Examiner Corrie V. Foster issued a Recommended Order Affirming Complaint in Part, Dismissing in Part, Recalculating Ratepayer Bills and Requiring Compliance with Commission Rules (Recommended Order). In the Recommended Order, Hearing Examiner Foster found that the Respondent, Sumare, L.P. (Sumare, Company or Respondent) had failed to calculate its bills in accordance with the Hot Water Capture, Cold Water Allocation Method (HWCCWA) provisions set forth in Commission Rule R18-8. The Hearing Examiner thereafter ordered:

> 1. That Respondent shall recalculate the Complainant's bills beginning with December 2012, until August 2013, using the correct regulated charges approved by the Commission;
>
> 2. That within 30 days of issuance of this Order, the Respondent shall submit its calculations (showing the values required on the bill [#1 through 7, above] for each bill recalculated) to the Commission for review and approval;
>
> 3. That the Respondent, if not already done so, shall immediately comply with Commission Rule R18-8, by including the required information on all its bills in the Sumter Square Apartments in Wake County, North Carolina[.]

On December 22, 2014, Complainant Carl Mascott (Complainant or Mr. Mascott) filed Complainant's Exceptions to Recommended Order of December 5, 2014 (Exceptions). In the Exceptions, the Complainant identified several exceptions to the Recommended Order. The Complainant did not, however, challenge the ultimate decision of the Recommended Order; nor did he request an oral argument in order to be heard on the exceptions.

COMPLAINANT'S EXCEPTIONS

In the Exceptions, the Complainant identified the following five discrete exceptions to the Recommended Order:

1. The Recommended Order contained the following factual errors.

   a. In Finding of Fact No. 11, the Recommended Order stated:

      11. The bills from December 2012 to May 2013 sent to Complainant by Respondent at Sumter Square Apartments do not comply with Commission Rule R18-8.

      This Finding of Fact should have stated that the Respondent's bills did not comply with Commission Rule R18-8 from December <u>2011</u> to May 2013.

   b. In Ordering Paragraph No. 1, the Recommended Order stated:

      1. That Respondent shall recalculate the Complainant's bills beginning with December 2012, until August 2013, using the correct regulated charges approved by the Commission.

      This Ordering Paragraph should have required Respondent to recalculate the Complainant's bills from December <u>2011</u>, until August 2013.

   c. Finding of Fact No. 14 indicated that the Complainant made an "oral" motion requesting a Commission order that directed the Respondent to stop billing its customers for water and sewer service until a final order was issued in the docket.

      The Complainant did not make an oral motion requesting that relief. Instead, the Complainant made a <u>written</u> motion which requested that the Commission direct the Respondent to stop using water purchase estimates when preparing its customers' bills.

   d. The discussion on page 7 of the Recommended Order erroneously implies that the billing practices in question had been in place since the Complainant began his residency in Sumter Square Apartments in 2007. At the time of the July 31, 2013 hearing, the questioned billing practices had only been in place for 20 months.

2. The Recommended Order ignores the Respondent's practice of secretly and without notice substituting data that had been previously provided by the City of Raleigh as a proxy of the customer's actual usage for the month in which the customer was being billed. To correct this oversight, the Commission should order the Company to utilize the actual data provided by the City of Raleigh when it calculates a customer's bill rather than substituting an estimated water use based on a prior usage data.

3. The Hearing Examiner allowed the Respondent to recalculate the Complainant's past bills. This was an error. The Commission should correct this error by requiring that the Company's bills be audited and recalculated by a qualified, disinterested third party.

4. The Hearing Examiner did not specifically require the Respondent to use actual data from the City of Raleigh to recalculate the Complainant's bills. This was an error. The Commission should correct this error by issuing an order directing the Respondent to use actual data from the City of Raleigh to recalculate the Complainant's bills.

5. Because of the conduct described in Paragraph No. 2, the Commission should order that the Respondent's billing practices be monitored by a qualified, disinterested third party for at least 12 months.

SUMARE'S RESPONSE

On January 22, 2015, the Respondent filed its Response to the Exceptions (Response). In the Response, the Company contended that none of the exceptions advanced by the Complainant warrant any change to the Recommended Order and that the Commission should adopt the Recommended Order as its final Order in this docket. In support of its contention, the Respondent set forth detailed refutations of each of the individual points made by the Complainant. Briefly summarized, the responses are:

1. Complainant's contention that there are factual errors as to the December 2012 timeframe identified in the Recommended Order lacks merit because that date correlates with the evidence produced by the Complainant during the hearing.

2. The Complainant's contention that his motion had been incorrectly characterized does not merit revision of the Recommended Order because, this error, even if true, was inconsequential since the substance of the motion was considered and addressed during the hearing. Therefore, this issue is moot.

3. The statement in the Recommended Order indicating that the Complainant had resided in the Sumter Square Apartments since 2007 did not imply that the Respondent had engaged in its current billing practices since that time. Moreover, the evidence and the Recommended Order clearly indicate that the Hearing Examiner was aware that the Respondent was first certified to "charge its tenants pursuant to the Hot Water Capture, Cold Water Allocation Method (HWCCWA), for water and sewer services" in November 2011 and that no complaint could have been made about that method before that time.

4. In an effort to generate the most accurate billing that it can on a going forward basis, the Company has taken steps to ensure that current water billing/usage data is made available to it on a timely basis by the City of Raleigh and to align the dates covered by its billings to the data provided by the City of Raleigh.

5. Since the Respondent has voluntarily taken the steps discussed in Item No. 4 above, there is no need to order the Company to take those steps.

6. The Complainant's request that an audit/review be conducted by a third-party certified public accountant is unwarranted since the Commission's staff is qualified, disinterested, and capable of reviewing the simple recalculation of the disputed bills.

7. There is no need for the Respondent's billing practices to be monitored by a disinterested third party because the Company has gained electronic access to City of Raleigh billing data and synchronized its billing practices with the City of Raleigh. In the future, these steps should prevent the use of a prior month's data to estimate the current month's usage that occurred with a customer's bills.

DISCUSSION

On November 9, 2011, the Respondent was issued a certificate of authority from the Commission to charge its tenants pursuant to the HWCCWA Method for water and sewer services. On May 10, 2013, the Complainant filed a complaint with the Commission alleging, among other things, that the Respondent's bills to him for water and sewer service failed to comply with the HWCCWA Method requirements of Commission Rule R18-8. After hearing all the evidence, Hearing Examiner Foster found merit to the Complaint and ordered the Respondent to recalculate the Complainant's bills from December 2012 until August 2013.

While Mr. Mascott agrees with the ultimate conclusion reached in the Recommended Order, by these exceptions, he challenges the accuracy of some of the factual findings contained in the Recommended Order and the failure of the Recommended Order to require more prescriptive directives to the Respondent and/or to require more stringent oversight of the Respondent as it takes corrective action to remedy the problems identified in the Recommended Order. In its Response, the Company asserts that the factual findings are correct because they are in line with the Complainant's evidence, that the Complainant's challenge to the Recommended Order's mischaracterization of the Complainant's oral/written motion was inconsequential in the scheme of things and mooted by the subsequent hearing, and, finally, that there is no need for more stringent oversight or prescriptive directives to the Respondent.

After carefully considering the pleadings, the Recommended Order, the transcript of the July 2013 hearing, the Exceptions of the Complainant, the Responses of the Company and the entire record, the Commission finds and so concludes that the Hearing Examiner erred in Finding of Fact No. 11, and the corresponding provisions in the Order relating to that finding which imply that the Respondent's billing issues began in December 2012 and that efforts to remediate those issues should begin as of that date. The Commission reaches this conclusion because the evidence produced by the Company at the hearing clearly and unambiguously indicates that the Respondent and/or its agent NWP Services Corporation (NWP) first began to bill the residents of Sumter Square Apartments utilizing the HWCCWA bill calculation method in March- 2012. Sumare Witness Carleen Giles Direct Testimony, Tp. 107, Line 22. Further, the evidence indicates the bills that were submitted to the residents from the March-2012 timeframe until the date of the hearing were incorrect because the bills did not contain one or more of the data points that Commission Rule R18-8 requires to be utilized to calculate water and sewer usage by the HWCCWA method.[1] Sumare Witness Brian Willie Direct Testimony, Tp. 67, Lines 19-24.

[1] See the testimony of Respondent Witness Brian Willie, who, after acknowledging that the substance of Mr. Mascott's complaint concerned the failure of the bills rendered by the Respondent to comply with the requirements in Commission Rule R18-8(d) and being asked to state what action had been taken to address the Complainant's concerns, said the following:

The aforementioned evidence was presented by the Company in its case in chief. It was admitted without objection, is material to the matters alleged in the Complaint, and is directly relevant to the question of the appropriate date that the Respondent should begin the bill recalculation process. It was not contradicted by any other evidence produced during the hearing and it is the only direct evidence[1] adduced during the hearing which clearly and directly establishes the March 2012 bill as the first incorrectly calculated bill using the HWCCWA method which was submitted to the residents of Sumter Square Apartments by Sumare. Because of this evidence, it was error for the Hearing Examiner to find that the December 2012 bill was the first bill that was submitted to the residents utilizing the HWCCWA method.

In its Response, the Company argues that the Recommended Order's findings in this regard are correct because the evidence presented by the Complainant corresponds with these dates and bills. This argument lacks merit because it suggests that the decisions made by the Hearing Examiner and that this Commission's review of the correctness of those decisions should be based solely on the evidence produced by the Complainant during the hearing.

There is no statutory or legal basis to support such an argument. In rendering final judgments in a complaint proceeding, the Hearing Examiner, as well as the Commission, when it reviews those judgments, must consider all relevant and admissible evidence. Having done so, in this instance, the Commission must conclude that the December 2012 date cited in Finding of Fact No. 11 in the Recommended Order is incorrect and that this error must, therefore, be corrected and revised to read as follows:

> 11. The bills from March 2012 to May 2013 sent to Complainant by Respondent at Sumter Square Apartments do not comply with Commission Rule R18-8.

Similarly, for the reason stated above, Ordering Paragraph No. 1 should be revised as follows:

> 1. That Respondent shall recalculate the Complainant's bills beginning with March 2012, until August 2013, using the correct regulated charges approved by the Commission.

> As I mentioned, some of these items had been on the bill from the beginning. And we were not certain exactly why other items were not appearing on the bill. It may have just been a data input error. But its[sic] now been corrected since the March billing. All items except for number 5 are currently on the bill. Emphasis added. Tp. 67, Lines 19-24.

[1] In his Exceptions, the Complainant requested that the Commission revise Finding of Fact No. 11 and the corresponding ordering paragraphs to reflect that Sumare had submitted bills to him that did not comply with Commission Rule R18-8 since December 2011 and to order that his bills be recalculated from that date. While the Complainant's factual predicate is indeed correct, i.e. that bills submitted to him did not comply with Commission Rule R18-8 since December 2011, there is no evidence in this record that Sumare billed or attempted to bill the Complainant or any other Sumter Square Apartment resident utilizing the HWCCWA method before March 2012. Thus, to the extent that the Complainant is suggesting that the evidence presented during the hearing indicated that the Sumter Square Apartments water and sewer bills have been miscalculated using the HWCCWA method since December 2011, he is mistaken. Thus, the provisions shall not be revised to reflect the December 2011 date.

Having resolved the Complainant's contention that the Recommended Order incorrectly established the December 2012 bill and date as the first bill by which the Respondent calculated its customers' water and sewer usage by utilizing the HWCCWA method, the Commission now turns its attention to the Complainant's contention that the Respondent should be required to retain a qualified, disinterested third party, i.e., a certified public accountant, to recalculate the water and sewer bills that were previously submitted to Complainant; that the Respondent should be directed to utilize actual data provided by the City of Raleigh in calculating water and sewer bills; and that the Respondent's compliance with the Commission's directives should be overseen by a qualified, disinterested third party. After carefully considering the pleadings, the Recommended Order, the transcript of the July 2013 hearing, the Exceptions of the Complainant, the Responses of the Company and the entire record, the Commission finds and so concludes that the remaining exceptions raised and proposed by the Complainant should hereby be overruled and denied for the reasons set forth in the Company's Response.

More particularly, the Commission finds and so concludes that there is no need for the Company to retain a qualified, disinterested third party to monitor and oversee the Company's implementation of the corrective actions that are required by the Commission's findings and conclusions without clear and convincing evidence that the Respondent's prior billing actions were malevolent and/or that the Respondent will not adhere to the voluntary commitments that it has undertaken to correct its billing practices in the future. The Commission's review of the evidence heretofore submitted in this docket would not support such findings by the Commission. In the absence of such findings, the Commission is therefore compelled to conclude that the Respondent would exercise its duties in this regard in good faith and that the Commission's staff and the Public Staff are capable and qualified to oversee the Company's compliance with Commission Rules and directives issued in Commission orders.

CONCLUSIONS

For the previously set forth reasons, the Commission, therefore, concludes that, with the exception of the matters revised herein, the record in this docket supports the findings and conclusions of the Recommended Order, and that, for that reason, the Recommended Order, except as revised herein, should therefore be affirmed.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of February, 2015.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Chairman Edward S. Finley, Jr., and Commissioner Jerry C. Dockham did not participate in this decision.

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E-100, SUB 142; SP-4038, SUB 0 -- Order Dismissing Without Prejudice Application for Certificate of Public Convenience and Necessity (11/18/2015); Errata Order (11/24/2015)

E-100, SUB 142; SP-4039, SUB 0 -- Order Dismissing Without Prejudice Application for Certificate of Public Convenience and Necessity (11/18/2015)

E-100, SUB 142; SP-4043, SUB 0 -- Order Dismissing Without Prejudice Application for Certificate of Public Convenience and Necessity (11/18/2015)

E-100, SUB 142; SP-4045, SUB 0 -- Order Dismissing Without Prejudice Application for Certificate of Public Convenience and Necessity (11/18/2015)

GENERAL ORDERS – Electric *(Continued)*

E-100, SUB 142; SP-4047, SUB 0 -- Order Dismissing Without Prejudice Application for Certificate of Public Convenience and Necessity (11/18/2015)

E-100, SUB 142; SP-4064, SUB 0 -- Order Dismissing Without Prejudice Application for Certificate of Public Convenience and Necessity (11/18/2015)

E-100, SUB 143 -- Order Approving 2013 REPS Compliance Reports (09/08/2015)

GENERAL ORDERS -- Electric Reseller

ER-100, SUB 0; ER-100, SUB 2 -- Order Amending Commission Rule R22 and Forms ER-1 and ER-2 (07/20/2015); Errata Order (07/23/2015)

GENERAL ORDERS – Small Power Producers

SP-100, SUB 9; SP-967, SUB 0 -- Order Granting Request for Supplemental Declaratory Ruling and Requiring Withdrawal of Report of Proposed Construction and Registration Statement (12/17/2015)

GENERAL ORDERS -- Telecommunications

P-100, SUB 99; P-100, SUB 99A; P-1154, SUB 5 -- Order Reinstating Certificate and Imposing Penalty for Noncompliance with Commission Orders, Rules, and Regulations (06/02/2015)

P-100, SUB 133C; P-1310, SUB 1 -- Order Granting Petition to Discontinue Service and Cancelling Designation as Eligible Telephone Carrier (03/05/2015)

P-100, SUB 170; P-1558, SUB 1 -- Order Reinstating Certificate (07/10/2015)

GENERAL ORDERS – Transportation

T-100, SUB 98; T-4277, SUB 6 -- Order Cancelling Certificate of Exemption (10/27/2015)

T-100, SUB 98; T-4531, SUB 1 -- Order Cancelling Certificate of Exemption (10/27/2015)

T-100, SUB 98; T-4309, SUB 9 -- Order Cancelling Certificate of Exemption (10/27/2015)

T-100, SUB 49 -- Order Granting Annual Rate Increase (11/25/2015)

GENERAL ORDERS – Water and Sewer

W-100, SUB 56 -- Recommended Order Finding Violation and Appropriate Penalty (10/29/2015); Recommended Order Finding Violation and Appropriate Penalty (10/29/2015)

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BUS BROKER -- Cancellation of Certificate
Caro-Lan Tours, Inc. -- B-464, SUB 1; Order Cancelling Broker's License (12/04/2015)

BUS BROKER -- Certificate
Trolleys, Inc., d/b/a Sunway Charters -- B-704, SUB 1; Order Granting Common Carrier Authority (09/16/2015); Errata Order (09/17/2015)

BUS BROKER – Sale/Transfer
Evergreen Trails, Inc., d/b/a Horizon Coach Lines -- B-703, SUB 2; B-704, SUB 0; Order Approving Transfer (06/10/2015)

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ELECTRIC -- Adjustments of Rates/Charges
New River Light & Power Co. -- E-34, SUB 43; Order Approving Purchased Power Adjustment Factor (01/20/2015)
Western Carolina University -- E-35, SUB 44; Order Approving Purchased Power Cost Rider (01/20/2015)

ELECTRIC -- Certificate
Duke Energy Progress, LLC -- E-2,
SUB 1063; Order Issuing Certificate of Public Convenience and Necessity (04/14/2015)
SUB 1066; Order Issuing Certificate of Public Convenience and Necessity (08/03/2015)

ELECTRIC -- Complaint

Dominion North Carolina Power -- E-22,

SUB 510; Order Closing Docket *(Fresh Air Energy II, LLC & Fresh Air Energy X, LLC)* (03/04/2015)

SUB 518; Order Closing Docket *(Tarboro Solar LLC)* (06/02/2015)

Duke Energy Carolinas, LLC -- E-7,

SUB 1039; Recommended Order Dismissing Complaint *(LeeNard Morrow)* (03/05/2015); Errata Order (03/17/2015)

SUB 1070; Order Dismissing Complaint and Closing Docket *(Shirley B. Dean)* (01/05/2015)

SUB 1071; Order Dismissing Complaint and Closing Docket *(Phyllis Michelle Brown)* (03/17/2015)

SUB 1076; Order Dismissing Complaint and Denying Motions to Enjoin *(Angel Torres)* (11/13/2015)

SUB 1080; Order Dismiss. Compliant and Closing Docket *(K. E. Krispen Culbertson)* (07/20/2015)

SUB 1085; Order Dismissing Complaint and Closing Docket *(L. Tonda Talbert)* (06/30/2015)

SUB 1097; Order Dismissing Complaint and Closing Docket *(Robert & Glenda Carini)* (12/22/2015)

Duke Energy Progress, LLC -- E 2, SUB 1074; Order Closing Docket *(ABCZ Solar, LLC)* (07/29/2015)

ELECTRIC -- Contract/Agreements

Dominion North Carolina Power – E-22, SUB 476; Order Accepting Addition of Service to Agreement and Approving Payments Pursuant Thereto (01/09/2015)

Duke Energy Carolinas, LLC -- E-7,

SUB 1066; E-2, SUB 1058; Order Closing Docket (02/23/2015)

SUB 1077; Order Closing Docket (07/08/2015)

SUB 1082; Order Allowing Contract to Become Effective as Filed (05/27/2015)

ELECTRIC -- Electric Transmission Line Certificate

Duke Energy Progress, LLC -- E-2,

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ELECTRIC – Filings Due Per Order or Rule

Duke Energy Carolinas, LLC -- E-7, SUB 986A; Order Accepting Financing Plan (02/03/2015); Errata Order (02/04/2015)

Duke Energy Progress, LLC -- E-2, SUB 998A; E-7, SUB 986A; Order Accepting Affiliate Agreement and Allowing Payment Thereunder (02/10/2015)

North Carolina Eastern Municipal Power Agency -- E-48, SUB 7; Order Extending Certificate and Requiring Reports (02/10/2015)

ELECTRIC -- Merger

Duke Energy Carolinas, LLC -- E-7,

SUB 986; E-2, SUB 998; E-7, SUB 986A; E-2, SUB 998A; Order Approving Revisions to Regulatory Conditions Nos. 7.7 and 7.8 (03/24/2015)

SUB 986; E-2, SUB 998; Order Approving Transfer of Employees and Amendment to Regulatory Conditions (11/25/2015)

ELECTRIC -- Miscellaneous

Duke Energy Progress, LLC – E-2,

SUB 1041; Order Approving Revised Lighting Schedules (06/02/2015)

SUB 1092; E-7, SUB 1095; Order Accepting Advance Notice, Accepting Affiliate Agreement and Waiving Regulatory Conditions (10/27/2015)

Waltonwood Lake Boone, LLC -- E-73, SUB 0; Order Approving Master Metering Exemption (09/29/2015)

ELECTRIC – Rate Increase

Dominion North Carolina Power – E-22, SUB 479; E-22, SUB 517; E-22, SUB 519; Order Provisionally Approving Amended Schedule NS and Scheduling Oral Argument (04/29/2015)

Duke Energy Carolinas, LLC -- E-7,

SUB 487; E-7, SUB 828; E-7, SUB 989; Order Approving EDPR Rider (06/23/2015);

SUB 1026; Order Approving Rider (06/23/2015); Order Approving Revised Schedule HP (07/21/2015)

Duke Energy Progress, LLC – E-2,

SUB 1023; Order Approving Revised Rider LLC-3 (07/21/2015); Order Approving Coal Inventory True-Up Rider (11/03/2015)

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<u>ELECTRIC – Rate Schedules/Riders/Service Rules & Regulations</u>

Dominion North Carolina Power – E-22, SUB 525; Order Approving REPS and REPS EMF RIDERS and 2014 REPS Compliance (12/16/2015)

Duke Energy Carolinas, LLC -- E-7,
SUB 1032; Order Approving Revised Rider PS (07/21/2015)
SUB 1074; Order Approving REPS and REPS EMF Riders and 2014 REPS Compliance (07/30/2015); Order Retiring RECS (11/23/2015)
SUB 1094; Order Approv. Requested Revisions to Lighting Rate Schedules (10/13/2015)

Duke Energy Progress, LLC. – E-2,
SUB 1072; Order Approving Pilot Program (08/19/2015)
SUB 1085; Order Approving Program (10/06/2015)
SUB 1086; Order Approving Program (10/27/2015)

<u>ELECTRIC – Reports</u>

Dominion North Carolina Power – E-22, SUB 523; Order Approving Program (10/06/2015)

<u>ELECTRIC – Sale/Transfer</u>

Dominion North Carolina Power – E-22, SUB 418; Order Accepting Agreement as Resolution of Petition (08/14/2015)

Duke Energy Carolinas, LLC -- E-7,
SUB 1007; Order Closing Docket (02/23/2015)
SUB 1011; Order Closing Docket (02/23/2015)

Duke Energy Progress, LLC – E-2, SUB 1067; E-48, SUB 8; Order Approving Transfer of Certificate and Ownership Interests in Generating Facilities (05/12/2015); Order Transfering Certificate of Public Convenience and Necessity (08/13/2015)

<u>ELECTRIC – Securities</u>

Duke Energy Progress, LLC -- E-2, SUB 939; E-2 SUB 1049; E-7, SUB 862; E-7, SUB 1006; Order Approving Deferral Accounting (03/30/2015)

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Electric Cooperatives -- Miscellaneous

Pee Dee Electric Membership Corporation -- EC-34, SUB 51; Order Granting Exemption (02/03/2015)

ELECTRIC MERCHANT PLANTS

ELECTRIC MERCHANT PLANTS – Certificate

North Carolina Renewable Power-Lumberton, LLC -- EMP-91, SUB 0; SP-5640, SUB 0 – Order Amending CPCN, Accepting Registration and Approving Method of Calculating Portions of Biomass Fuel and Thermal Energy (05/20/2015)

ELECTRIC MERCHANT PLANTS – Filings Due Per Order or Rule

Grandview Wind Farm, LLC -- EMP-89, SUB 0; Order Accepting Registration of New Renewable Energy Facility (03/13/2015)

Logan's Gap Wind, LLC -- EMP-88, SUB 0; Order Accepting Registration of New Renewable Energy Facility (04/14/2015)

Miami Wind I, LLC -- EMP-87, SUB 0; Order Accepting Registration of New Renewable Energy Facility (04/30/2015); EMP-87, SUB 0; EMP-88, SUB 0; Errata Order (05/01/2015)

ELECTRIC MERCHANT PLANTS – Sale/Transfer

East Carolina Energy Investments, LLC -- EMP-84, SUB 0; EMP-85, SUB 0; EMP-90, SUB 0; EMP-91, SUB 0; Order on Transfer of Facilities and Certificates (04/28/2015)

Morgans Corner Solar Energy LLC -- EMP-86, SUB 0; E-22, SUB 528; Order Approving Transfer of Certificate Subject to Conditions (10/27/2015)

ELECTRIC RESELLER

ELECTRIC RESELLER – Cancellation of Certificate

Progress Wilmington, LLC -- ER-40, SUB 0; ER-40, SUB 1; Order Cancelling Certificate of Authority (10/01/2015)

University Apartments Raleigh, LLC -- ER-8, SUB 1; ER-8, SUB 2; Order Cancelling Certificate of Authority (12/18/2015)

ELECTRIC RESELLER – Certificate

Gang of Five Guys, LLC -- ER-51, SUB 0; Order Granting Certificate of Authority (08/24/2015)

Carolina Cove Apartments, LLC -- ER-53, SUB 0; Order Granting Certificate of Authority (07/07/2015)

Chapman Place, LLC -- ER-45, SUB 0; Order Granting Certificate of Authority (08/12/2015)

Granite Place Apartments, LLC -- ER-44, SUB 0; Order Granting Certificate of Authority (05/04/2015)

Granwood Properties, LLC -- ER-47; SUB 0; Order Granting Certificate of Authority (03/09/2015)

Greensboro D/E/P, LLC -- ER-36, SUB 0; Order Granting Certificate of Authority (02/02/2015)

North Carolina Student Housing, LLC -- ER-46, SUB 0; Order Granting Certificate of Authority (08/24/2015)

Spartan Square, LLC -- ER-49, SUB 0; Order Granting Certificate of Authority (03/30/2015)

Stanhope 2013 LLC -- ER-57, SUB 0; Order Granting Certificate of Authority (10/06/2015)

The Edge Student Housing, LLC -- ER-42, SUB 0; Order Granting Certificate of Authority (08/24/2015)

Three Moose Village, LLC -- ER-54, SUB 0; Order Granting Certificate of Authority (07/07/2015)

UNCC Millennium, LLC -- ER-37, SUB 0; Order Granting Certificate of Authority (05/04/2015)

Walden Station Properties, LLC -- ER-32, SUB 0; Order Granting Certificate of Authority (06/01/2015)

ELECTRIC RESELLER – Sale/Transfer

Wilmington Student Housing, LLC -- ER-15,

SUB 0; ER-15, SUB 2; ER-56, SUB 0; Order Granting Transfer of Certificate of Authority (08/12/2015)

SUB 1; ER-15, SUB 3; ER-56, SUB 1; Order Granting Transfer of Certificate of Authority (08/12/2015)

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FERRYBOATS -- Certificate

Crystal Blue Holding, Co., d/b/a Morehead Ferry Service -- A-76, SUB 0; Order Granting Common Carrier Authority (03/30/2015); Reissued Order Granting Common Carrier Authority (04/01/2015)

FERRYBOATS – Suspension

LO'R Decks at Calico Jacks Ferry -- A-69, SUB 2; Order Granting Authorized Suspension (09/09/2015)

Waterfront Ferry Service, Inc. -- A-55, SUB 4; Order Granting Authorized Suspension (01/26/2015)

NATURAL GAS

NATURAL GAS – Adjustments of Rates/Charges

Cardinal Pipeline Company, LLC -- G-39,
SUB 34; Order Approving Fuel Tracker and Electric Power Cost Adjustment (03/30/2015)

Frontier Natural Gas Company, LLC -- G-40,
SUB 129; Order Allowing Rate Changes Effective April 1, 2015 (03/30/2015)

Piedmont Natural Gas Company, Inc. -- G-9,
SUB 642; G-9, SUB 659; Order Approving Rate Adjustments Effective February 1, 2015 (01/26/2015)
SUB 661; Order Allowing Rate Changes Effective February 1, 2015 (01/26/2015)
SUB 663; Order Allowing Rate Changes Effective March 1, 2015 (02/25/2015)
SUB 664; Order Approving Rate Adjustments Effective April 1, 2015 (03/30/2015)
SUB 665; Order Allowing Rate Changes Effective April 1, 2015 (03/30/2015)
SUB 669; Order Approving Rate Changes Effective June 1, 2015 (06/01/2015)
SUB 675; M-100, SUB 138; G-9, SUB 631; G-9, SUB 676; Order Approving Rate Adjustments Effective November 1, 2015 (11/03/2015)
SUB 679; Order Allowing Rate Changes Effective December 1, 2015 (12/01/2015)
SUB 681; Order Approving Decrease in Rates (12/14/2015)

NATURAL GAS – Adjustments of Rates/Charges *(Continued)*

Public Service Company of North Carolina, Inc. -- G-5,
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SUB 556; Order Allowing Rate Changes Effective March 1, 2015 (02/25/2015)
SUB 557; Order Approving Rate Adjustments Effective April 1, 2015 (03/30/2015)
SUB 558; Order on Annual Review of Gas Costs (10/02/2015)
SUB 560; Order Approving Rate Adjustments Effective October 1, 2015 (09/28/2015)
SUB 561; Order Approving Rate Adjustments Effective November 1, 2015 (11/03/2015)

NATURAL GAS – Contract/Agreements

Piedmont Natural Gas Company, Inc. -- G-9,
SUB 657; Order Approving Agreement (01/14/2015)
SUB 666; Order Approving Agreement (06/02/2015)
SUB 667; Order Approving Agreement (06/02/2015)
SUB 668; Order Allowing Agreement to Become Effective (07/21/2015)
SUB 670; Order Approving Agreement (08/31/2015)
SUB 671; Order Approving Agreement (08/04/2015)

Public Service Company of North Carolina, Inc. -- G-5, SUB 559; Order Allowing Agreement to Become Effective (10/06/2015)

NATURAL GAS – Filings Due Per Order or Rule

Piedmont Natural Gas Company, Inc. -- G-9, SUB 586; Order Approving Second Amendment to Credit Facility (11/24/2015)

NATURAL GAS – Miscellaneous

Frontier Natural Gas Company, LLC **--** G-40, SUB 117; Order Closing Docket (06/02/2015)

NATURAL GAS – Rate Increase

Piedmont Natural Gas Company, Inc. -- G-9, SUB 631; G-9, SUB 642; Order Approving Rate Adjustments Effective December 1, 2015 (12/01/2015)

NATURAL GAS – Rate Schedules/Riders/Service Rules & Regulations

Piedmont Natural Gas Company, Inc. -- G-9,
SUB 672; Order Allowing Modifications (10/06/2015)
SUB 677; Order Granting Authority to Issue and Sell Securities (10/29/2015)

NATURAL GAS – Securities

Public Service Company of North Carolina, Inc. -- G-5, SUB 562; Order Granting Authority to Issue Securities (12/04/2015)

RENEWABLE ENERGY THERMAL

RENEWABLE ENERGY THERMAL – Filings Due Per Order or Rule

RET-10, SUB 0; SP-628, SUB 2; SP-629, SUB 2; SP-630, SUB 2; SP-630, SUB 4; SP-630, SUB 6; SP-630, SUB 9; SP-630, SUB 10; SP-631, SUB 2; SP-631, SUB 4; SP-631, SUB 6; SP-930, SUB 2; SP-930, SUB 5; SP-930, SUB 6; SP-976, SUB 1; SP-977, SUB 1; SP-1275, SUB 2; SP-1275, SUB 4; SP-1287, SUB 1; SP-1520, SUB 1; SP-1520, SUB 3; SP-1521, SUB 1; SP-1522, SUB 1; SP-1522, SUB 3; SP-1538, SUB 1; SP-1539, SUB 1; SP-1580, SUB 1; SP-1582, SUB 1; SP-1582, SUB 3; SP-2397, SUB 1; SP-2470, SUB 1; SP-3231, SUB 1; SP-1082, SUB 0; SP-1175, SUB 0; SP-1176, SUB 0; SP-1177, SUB 0; SP-1179, SUB 0; SP-1180, SUB 0; SP-1181, SUB 0; SP-1182, SUB 0; SP-1183, SUB 0; SP-1184, SUB 0; SP-674, SUB 0; EMP-49, SUB 0; EMP-50, SUB 0; EMP-51, SUB 0; EMP-40, SUB 0; EMP-35, SUB 0; EMP-14, SUB 1; SP-405, SUB 1; SP-895, SUB 1; SP-1108, SUB 4; SP-1108, SUB 5; SP-1108, SUB 6; SP-1221, SUB 0; SP-1393, SUB 1; SP-1518, SUB 0; SP-1519, SUB 0; SP-1565, SUB 11; SP-1635, SUB 0; SP-1765, SUB 1; SP-1794, SUB 1; SP-1795, SUB 1; SP-1846, SUB 1; SP-1942, SUB 0; SP-2152, SUB 1; SP-2164, SUB 0; SP-2342, SUB 0; SP-2371, SUB 0; SP-2373, SUB 0; SP-2401, SUB 1; SP-2423, SUB 1; SP-2443, SUB 0; SP-2444, SUB 0; SP-2484, SUB 1; SP-2485, SUB 0; SP-2576, SUB 1; SP-2704, SUB 0; SP-2705, SUB 0; SP-2707, SUB 0; SP-2708, SUB 0; SP-2710, SUB 0; SP-2711, SUB 0; SP-2712, SUB 0; SP-2715, SUB 0; SP-2720, SUB 0; SP-2721, SUB 0; SP-2893, SUB 0; SP-2895, SUB 0; SP-2896, SUB 0; SP-2900, SUB 0; SP-2922, SUB 0; SP-2972, SUB 0; SP-2990, SUB 0; SP-3024, SUB 0; SP-3026, SUB 0; SP-3103, SUB 0; SP-3105, SUB 0; SP-3176, SUB 0; SP-3181, SUB 0; SP-3225, SUB 0; SP-3239, SUB 0; SP-3255, SUB 0; SP-3380, SUB 0; SP-3414, SUB 0; SP-3436, SUB 0; SP-3444, SUB 0; SP-3450, SUB 0; SP-3492, SUB 0; SP-3512, SUB 0; SP-3520, SUB 0; SP-3619, SUB 0; SP-3666, SUB 0; SP-3673, SUB 0; SP-3897, SUB 0; SP-3898, SUB 0; SP-3899, SUB 0; SP-4005, SUB 0; SP-4024, SUB 0; EMP-36, SUB 0; SP-2795, SUB 0; EMP-66, SUB 0; EMP-41, SUB 0; EMP-31, SUB 0; EMP-32, SUB 0; EMP-34, SUB 0; SP-2802, SUB 0; E-100, SUB 130; Order Revoking Registrations of Renewable Energy Facilities and New Renewable Energy Facilities 12/02/2015)

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SHARED TELEPHONE TENANT

SHARED TELEPHONE TENANT – Cancellation of Certificate

Elizabeth City State University -- STS-24, SUB 1; Order Canceling Certificate (02/03/2015)

The University of North Carolina at Charlotte -- STS-28, SUB 1; Order Canceling Certificate (02/24/2015)

SPECIAL CERTIFICATE/PAYPHONES

SPECIAL CERTIFICATE/PAYPHONES – Cancellation of Certificate

Ed, Jr. & Brenda Angier -- SC-1711, SUB 1; Order Canceling Certificate (08/24/2015)

JGS Payphones; J. Graham Singleton, d/b/a -- SC-656, SUB 2; Order Canceling Certificate (10/22/2015)

KELLEE Communications Group, Inc. -- SC-1477, SUB 2; Order Canceling Certificate (05/20/2015)

McCanna; C. E. -- SC-1637, SUB 1; Order Canceling Certificate (04/24/2015)

Somers; Claude S. -- SC-1761, SUB 1; Order Canceling Certificate (06/16/2015)

Southeastern Telephone Service, Inc. -- SC-1411, SUB 3; Order Canceling Certificate (10/22/2015)

Triad Triangle Telecom, d/b/a Issam Hashem -- SC-990, SUB 1; Order Canceling Certificate (01/28/2015)

SPECIAL CERTIFICATE/PAYPHONES – Certificate

Million Mile March, Inc. -- SC-1819, SUB 0; Order Issuing Certificate (09/28/2015)

SMALL POWER PRODUCERS

SMALL POWER PRODUCERS – Cancellation of Certificate

Cornstalk Solar, LLC -- SP-3811, SUB 0; Order Canceling Certificate of Public Convenience and Necessity and Registration (10/09/2015)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCERS – Certificate

ORDER AMENDING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REGISTRATION

Orders Issued

Company	Docket No.	Date
Project Sunday Development, LLC	SP-4106, SUB 0	(11/05/2015)
	SP-4106, SUB 1	(11/05/2015)
	SP-4106, SUB 2	(11/05/2015)
	SP-4106, SUB 3	(11/05/2015)
	SP-4106, SUB 4	(11/05/2015)
Whiteville Solar 1, LLC	SP-5577, SUB 0	(12/01/2015)

Barnhill Road Solar, LLC -- SP-5081, SUB 0, Order Amending Certificate of Public Convenience and Necessity (12/01/2015)

Bearford Solar II, LLC -- SP-3797, SUB 0; Order Amending Certificate of Public Convenience and Necessity, Registration and Public Notice (10/09/2015)

ESA Henderson NC, LLC -- SP-3540, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration Statement (01/07/2015)

Germantown Solar, LLC -- SP-4317, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration Statement (04/16/2015)

WBJE Solar LLC -- SP-4158, SUB 0; SP-4159, SUB 0; SP-4160, SUB 0; SP-4161, SUB 0; SP-4172, SUB 0; SP-4173, SUB 0; SP-4176, SUB 0; SP-4177, SUB 0; SP-4996, SUB 0; Order Denying Request for Waivers (06/12/2015)

ORDER ISSUING CERTIFICATE

Orders Issued

Company	Docket No.	Date
Aulander Earleys Solar LLC	SP-5307, SUB 0	(06/17/2015)
Aulander Holloman Solar, LLC	SP-5259, SUB 0	(06/17/2015)
BRE NC SOLAR 3, LLC	SP-6512, SUB 0	(12/15/2015)
Carnation Solar, LLC	SP-6051, SUB 0	(09/09/2015)
Colonial Eagle Solar, LLC	SP-4305, SUB 3	(02/25/2015)
	SP-4305, SUB 4	(02/25/2015)
Conetoe II Solar, LLC	SP-4483, SUB 0	(02/25/2015)
		(05/05/2015)
Duke Energy Renewables NC Solar, LLC	SP-5448, SUB 0	(07/21/2015)
Durham Solar, LLC	SP-4316, SUB 0	(06/17/2015)
Fisher Solar Farm, LLC	SP-3216, SUB 0	(01/20/2015)
Haslett Solar LLC	SP-6373, SUB 0	(11/03/2015)
Hobbsville Solar, LLC	SP-5718, SUB 0	(08/31/2015)
Johannes Gutenberg Solar, LLC	SP-5434, SUB 0	(07/08/2015)
Kelford Solar, LLC	SP-3209, SUB 0	(02/25/2015)

<u>SMALL POWER PRODUCERS – Certificate</u> *(Continued)*

ORDER ISSUING CERTIFICATE

<u>Orders Issued</u> *(Continued)*

Company	Docket No.	Date
Langdon Solar Farm, LLC	SP-3591, SUB 0	(08/31/2015)
Leggett Solar, LLC	SP-4396, SUB 0	(07/08/2015)
Moyock Caratoke Solar, LLC	SP-4631, SUB 0	(01/06/2015)
Overman Solar LLC	SP-5261, SUB 0	(12/15/2015)
Pecan Solar, LLC	SP-5273, SUB 0	(06/17/2015)
SunEnergy 1, LLC	SP-751, SUB 19	(02/25/2015)
Tracy Solar, LLC	SP-3437, SUB 0	(09/09/2015)
Violet Solar LLC	SP-5819, SUB 0	(08/31/2015)
Wadesboro Farm 2, LLC	SP-4558, SUB 0	(05/27/2015)
Washington Solar, LLC	SP-6053, SUB 0	(09/09/2015)
Wildwood Solar LLC	SP-5310, SUB 0	(06/17/2015)
Woodland Church Farm, LLC	SP-3404, SUB 0	(03/30/2015)

Albertson Solar, LLC – SP-3777, SUB 0; Recommended Order Granting Certificate (06/02/2015); Order Allowing Recommended Order to Become Effective and Final (06/05/2015)

Camden Mill Dam Road Solar, LLC -- SP-4230, SUB 0; Recommended Order Granting Certificate (03/10/2015)

Carol Jean Solar, LLC -- SP-2551, SUB 0; Recommended Order Granting Certificate (08/12/2015)

Shiloh Hook Solar, LLC -- SP-4104, SUB 0; Recommended Order Granting Certificate (03/10/2015)

Sunflower Solar, LLC -- SP-5272, SUB 0; Recommended Order Granting Certificate (08/25/2015)

United Shiloh Solar, LLC -- SP-4937, SUB 0; Recommended Order Granting Certificate (07/07/2015)

Upper Piedmont Renewables LLC -- SP-5002, SUB 0; Order Granting Certificate (09/17/2015)

Windsor Hwy. 17 Solar, LLC -- SP-4655, SUB 0; Recommended Order Granting Certificate (05/28/2015)

ORDER ISSUING AMENDED CERTIFICATE

<u>Orders Issued</u>

Company	Docket No.	Date
Andrew Solar, LLC	SP-3432, SUB 0	(12/08/2015)
Cabaniss Farm, LLC	SP-3829, SUB 0	(10/13/2015)
Innovative Solar 46, LLC	SP-3478, SUB 0	(12/01/2015)
Maxton Solar 1, LLC	SP-4287, SUB 0	(11/17/2015)
Nickelson Solar, LLC	SP-5549, SUB 0	(11/17/2015)
River Road Solar, LLC	SP-4260, SUB 0	(09/21/2015)

SMALL POWER PRODUCERS – Certificate *(Continued)*

ORDER ISSUING AMENDED CERTIFICATE
Orders Issued *(Continued)*

Company	Docket No.	Date
Spencer Farm, LLC	SP-3491, SUB 0	(12/08/2015)
Statesville Solar, LLC	SP-4323, SUB 0	(11/23/2015)

Bearford Solar II, LLC -- SP-3797, SUB 0; Order Reissuing Amended Certificate (11/17/2015)
Foxfire Farm, LLC -- SP-3377, SUB 0; Order Issuing Amended Certificate and Accepting Registration of New Renewable Energy Facility (02/10/2015)
Innovative Solar 46, LLC -- SP-3478, SUB 0; Order Allowing Limited Construction with Conditions (10/20/2015)
Mills Anson Farm, LLC -- SP-3451, SUB 0; Order Issuing Amended Certificate and Accepting Registration of New Renewable Energy Facility (08/11/2015)
Pecan Solar, LLC -- SP-5273, SUB 0; Order Issuing Amended Certificate and Accepting Registration of New Renewable Energy Facility (08/24/2015)

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Company	Docket No.	Date
Achilles Farm, LLC	SP-4563, SUB 0	(02/10/2015)
Ajax Solar, LLC	SP-5721, SUB 0	(07/28/2015)
Alexis Solar, LLC	SP-5040, SUB 0	(06/23/2015)
Anna Solar, LLC	SP-5043, SUB 0	(06/23/2015)
Arborgate Farm, LLC	SP-4890, SUB 0	(02/25/2015)
Arthur Solar, LLC	SP-5576, SUB 0	(06/30/2015)
Augustus Farm, LLC	SP-5713, SUB 0	(08/04/2015)
Baltimore Church Solar	SP-4332, SUB 0	(02/25/2015)
Barker Solar, LLC	SP-4786, SUB 0	(02/03/2015)
Beaker Farm, LLC	SP-4559, SUB 0	(01/06/2015)
Beetle Solar, LLC	SP-4250, SUB 0	(01/20/2015)
Belafonte Farm, LLC	SP-5252, SUB 0	(05/12/2015)
Bill Bryan Solar, LLC	SP-5328, SUB 0	(05/12/2015)

SMALL POWER PRODUCERS – Certificate *(Continued)*

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Bizzell Church Solar 1, LLC	SP-3834, SUB 10 SP-4394, SUB 0	(01/26/2015)
Bizzell Church Solar 2, LLC	SP-3834, SUB 9 SP-4393, SUB 0	(01/26/2015)
Bladen Solar, LLC	SP-5220, SUB 0	(06/30/2015)
Blue Bird Solar, LLC	SP-5076, SUB 0	(06/23/2015)
Bo Biggs Solar, LLC	SP-4904, SUB 0	(03/03/2015)
Bonnie Solar, LLC	SP-5056, SUB 0	(06/30/2015)
Bradley Farm, LLC	SP-3941, SUB 0	(03/10/2015)
Broadway Road Solar, LLC	SP-5474, SUB 0	(06/16/2015)
Brooke Solar, LLC	SP-5041, SUB 0	(06/23/2015)
Buckleberry Solar, LLC	SP-5275, SUB 0	(12/01/2015)
Bullock Solar, LLC	SP-5339, SUB 0	(07/07/2015)
Burrows Farm, LLC	SP-5820, SUB 0	(11/17/2015)
Candace Solar, LLC	SP-3873, SUB 0	(02/25/2015)
Canon Farm, LLC	SP-5885, SUB 0	(08/19/2015)
Cardinal Solar, LLC	SP-5053, SUB 0	(06/30/2015)
Carl Friedrich Gauss Solar, LLC	SP-4824, SUB 0	(03/03/2015)
Carolina Solar Energy II, LLC	SP-2363, SUB 25	(06/16/2015)
Carter Solar, LLC	SP-5075, SUB 0	(08/11/2015)
Carthage Solar, LLC	SP-4773, SUB 0	(03/30/2015)
Cash Solar, LLC	SP-5050, SUB 0	(06/23/2015)
Cedar Grove Solar, LLC	SP-4920, SUB 0	(03/24/2015)
Chickenfoot Solar, LLC	SP-4616, SUB 0	(02/10/2015)
Christina Solar, LLC	SP-5077, SUB 0	(06/23/2015)
Church Solar Farm, LLC	SP-6046, SUB 0	(10/27/2015)
Clark Mountain Solar, LLC	SP-4333, SUB 0	(03/24/2015)
Clayton Solar, LLC	SP-5058, SUB 0	(06/30/2015)
Clear Solar I, LLC	SP-5099, SUB 0	(06/23/2015)
Climax Solar Project, LLC	SP-6544, SUB 0	(12/01/2015)
Coggins Solar, LLC	SP-4335, SUB 0	(03/10/2015)
Cork Oak Solar, LLC	SP-5271, SUB 0	(08/19/2015)
Cotten Farm, LLC	SP-4767, SUB 0	(01/26/2015)
County Farm Solar, LLC	SP-4970, SUB 0	(03/10/2015)

SMALL POWER PRODUCERS – Certificate *(Continued)*

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Crawford Solar, LLC	SP-6546, SUB 0	(12/01/2015)
Crimson Solar, LLC	SP-6935, SUB 0	(12/15/2015)
Currin Solar Farm, LLC	SP-3631, SUB 0	(05/27/2015)
Daniel Solar, LLC	SP-5265, SUB 0	(10/06/2015)
Daystar Solar, LLC	SP-5067, SUB 0	(11/17/2015)
Deep Branch Farm, LLC	SP-4560, SUB 0	(02/10/2015)
Dowtin Farm, LLC	SP-4765, SUB 0	(01/26/2015)
Eagle Solar, LLC	SP-5055, SUB 0	(06/30/2015)
Edenton Airport Solar, LLC	SP-5442, SUB 0	(10/06/2015)
Ellington Solar I, LLC	SP-4942, SUB 0	(11/17/2015)
Ellington Solar II, LLC	SP-4941, SUB 0	(11/17/2015)
ESA Church Road Solar, LLC	SP-6151, SUB 0	(10/19/2015)
ESA Elm City NC, LLC	SP-4689, SUB 0	(02/25/2015)
ESA Hamlet NC, LLC	SP-4794, SUB 0	(02/25/2015)
ESA Princeton 2 NC, LLC	SP-4752, SUB 0	(01/20/2015)
Fire Solar I, LLC	SP-5100, SUB 0	(06/30/2015)
	SP-5100, SUB 1	(11/23/2015)
Five Forks Solar, LLC	SP-5440, SUB 0	(10/06/2015)
Flatwoods Solar, LLC	SP-5065, SUB 0	(05/19/2015)
Flint Hill Solar, LLC	SP-5062, SUB 0	(04/20/2015)
Flowers Solar, LLC	SP-5092, SUB 0	(05/05/2015)
Floyd Solar, LLC	SP-3852, SUB 0	(02/10/2015)
Foothills Renewables LLC	SP-5003, SUB 0	(03/24/2015)
Four Oaks Solar, LLC	SP-3834, SUB 46	(01/13/2015)
	SP-4468, SUB 0	
Fresh Air Energy II, LLC	SP-2665, SUB 32	(01/20/2015)
	SP-2665, SUB 35	(12/08/2015)
Goins Solar, LLC	SP-5330, SUB 0	(05/12/2015)
Grant Solar, LLC	SP-4412, SUB 0	(01/15/2015)
Grove Solar, LLC	SP-5066, SUB 0	(11/17/2015)
GTP 2, LLC	SP-4842, SUB 0	(02/25/2015)
Harvest Greenville I, LLC	SP-4693, SUB 0	(03/03/2015)
Hawk Solar, LLC	SP-5052, SUB 0	(06/23/2015)
Heedeh Solar, LLC	SP-5072, SUB 0	(06/23/2015)
Henry Farm, LLC	SP-5253, SUB 0	(05/05/2015)
Herndon Solar, LLC	SP-4480, SUB 4	(06/16/2015)
	SP-5331, SUB 0	

SMALL POWER PRODUCERS – Certificate *(Continued)*

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Orders Issued *(Continued)*

Company	Docket No.	Date
Higgins Solar, LLC	SP-5059, SUB 0	(06/30/2015)
Holden Solar Farm Number One, LLC	SP-5671, SUB 0	(08/24/2015)
Hood Farm Solar, LLC	SP-2363, SUB 21	(07/28/2015)
	SP-4474, SUB 0	
Hull Solar Farm, LLC	SP-6047, SUB 0	(10/27/2015)
Icarus Solar, LLC	SP-5070, SUB 0	(06/30/2015)
Iga Solar, LLC	SP-5048, SUB 0	(06/23/2015)
Infigen Energy US Development LLC	SP-4106, SUB 3	(01/20/2015)
	SP-4106, SUB 4	(04/20/2015)
Innovative Solar 65, LLC	SP-3896, SUB 0	(05/27/2015)
Innovative Solar 73, LLC	SP-5471, SUB 0	(07/21/2015)
Innovative Solar 79, LLC	SP-5472, SUB 0	(08/31/2015)
Iron Farm, LLC	SP-4532, SUB 0	(02/25/2015)
Izia Solar, LLC	SP-5042, SUB 0	(09/21/2015)
Jacob Solar, LLC	SP-2853, SUB 0	(01/20/2015)
Johnson Solar, LLC	SP-4012, SUB 0	(01/13/2015)
JSF, LLC	SP-5427, SUB 0	(06/23/2015)
June Solar, LLC	SP-5047, SUB 0	(06/23/2015)
Kathleen Solar, LLC	SP-5069, SUB 0	(06/30/2015)
LaGrange Solar 1, LLC	SP-3834, SUB 7	(01/13/2015)
	SP-4321, SUB 0	
LaGrange Solar 2, LLC	SP-3834, SUB 8	(01/26/2015)
	SP-4320, SUB 0	
Lane Solar Farm, LLC	SP-5196, SUB 0	(06/16/2015)
Lincoln Solar, LLC	SP-4614, SUB 0	(03/16/2015)
Lobelia Solar, LLC	SP-4774, SUB 0	(02/03/2015)
Longleaf Solar, LLC	SP-5038, SUB 0	(06/23/2015)
Louisburg Solar 1, LLC	SP-5475, SUB 0	(07/08/2015)
Lyon Solar, LLC	SP-5593, SUB 0	(07/08/2015)
Manford Solar, LLC	SP-4653, SUB 0	(06/30/2015)
Matthews Solar Farm, LLC	SP-6045, SUB 0	(10/27/2015)
McLean Homestead, LLC	SP-6303, SUB 0	(10/19/2015)
Meadowlark Solar, LLC	SP-5229, SUB 0	(05/19/2015)

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ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
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Company	Docket No.	Date
Mill Pond Solar Farm, LLC	SP-5589, SUB 0	(06/30/2015)
Mills Anson Farm, LLC	SP-3451, SUB 0	(02/25/2015)
Misenheimer Farm, LLC	SP-3381, SUB 0	(07/21/2015)
MMG Solar Fusion LLC	SP-3268, SUB 0	(04/06/2015)
Molly Branch Solar, LLC	SP-5064, SUB 0	(03/30/2015)
Moore Solar, LLC	SP-4081, SUB 0	(01/20/2015)
Morrison Solar Park LLC	SP-3269, SUB 0	(04/06/2015)
Murdock Solar, LLC	SP-3434, SUB 0	(02/10/2015)
Nash 97 Solar 2, LLC	SP-4650, SUB 0	(02/25/2015)
Nickelson Solar LLC	SP-5549, SUB 0	(08/11/2015)
Nickelson Solar 2, LLC	SP-5523, SUB 0	(06/16/2015)
North Nash Farm, LLC	SP-3669, SUB 0	(06/02/2015)
North Webb Solar, LLC	SP-4649, SUB 0	(03/16/2015)
North 301 Solar, LLC	SP-5422, SUB 0	(10/06/2015)
Old Wire Farm, LLC	SP-4593, SUB 0	(05/12/2015)
Orbit Energy Charlotte, LLC	SP-4854, SUB 0	(06/02/2015)
Organ Church Solar, LLC	SP-5588, SUB 0	(06/30/2015)
Oxford Solar 2, LLC	SP-3834, SUB 28 SP-4404, SUB 0	(01/26/2015)
Pikeville Farm, LLC	SP-3395, SUB 0	(05/27/2015)
Pine Valley Solar Farm, LLC	SP-6224, SUB 0	(12/01/2015)
Piper Solar, LLC	SP-5060, SUB 0	(06/30/2015)
Pleasant Grove Solar, LLC	SP-3868, SUB 1	(03/16/2015)
Porter Solar, LLC	SP-3875, SUB 0	(04/06/2015)
Progressive Farm Solar, LLC	SP-4903, SUB 0	(02/25/2015)
RB Solar, LLC	SP-5467, SUB 0	(08/24/2015)
Red Mountain Solar, LLC	SP-5186, SUB 0	(05/12/2015)
Red Oak Solar Farm, LLC	SP-5251, SUB 0	(05/12/2015)
Reunion Solar, LLC	SP-4663, SUB 0	(12/15/2015)
Robin Solar, LLC	SP-5054, SUB 0	(06/30/2015)
Roman Solar, LLC	SP-5074, SUB 0	(08/11/2015)
Roxboro Solar Farm, LLC	SP-3676, SUB 0	(05/27/2015)
Royal Solar, LLC	SP-3708, SUB 0	(01/20/2015)
Runway Farm, LLC	SP-5250, SUB 0	(05/05/2015)
Sabattus Solar, LLC	SP-3810, SUB 0	(06/16/2015)
Sadie Solar, LLC	SP-5044, SUB 0	(06/23/2015)
Sadiebrook Solar, LLC	SP-5344, SUB 0	(06/30/2015)
Shakespeare Solar, LLC	SP-5269, SUB 0	(12/01/2015)
Shelter Solar, LLC	SP-5037, SUB 0	(06/23/2015)

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ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
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Company	Docket No.	Date
Shine Solar I, LLC	SP-5098, SUB 0	(08/31/2015)
Shoe Creek Solar, LLC	SP-5219, SUB 0	(05/19/2015)
Shoeheel Solar Farm, LLC	SP-4057, SUB 0	(04/20/2015)
Signature Solar, LLC	SP-5039, SUB 0	(06/23/2015)
Siler City Solar 2, LLC	SP-5611, SUB 0	(06/30/2015)
Siler Solar, LLC	SP-3834, SUB 39	(01/14/2015)
	SP-4405, SUB 0	
Snake Solar, LLC	SP-4654, SUB 0	(06/30/2015)
Sneads Grove Farm, LLC	SP-6194, SUB 0	(10/13/2015)
Soy Solar, LLC	SP-4912, SUB 0	(03/10/2015)
Spring Hope Solar, LLC	SP-3834, SUB 37	(02/25/2015)
	SP-4447, SUB 0	
Spring Hope Solar 3, LLC	SP-3834, SUB 29	(01/26/2015)
	SP-4452, SUB 0	
St. Andrews Solar Farm, LLC	SP-3488, SUB 0	(05/12/2015)
	SP-3488, SUB 1	
St. Pauls Solar 1, LLC	SP-4395, SUB 0	(01/13/2015)
St. Pauls Solar 2, LLC	SP-3834, SUB 13	(02/03/2015)
	SP-4397, SUB 0	
St. Pauls Solar 3, LLC	SP-3834, SUB 14	(02/25/2015)
	SP-4398, SUB 0	
Stainback Solar Farm, LLC	SP-3629, SUB 0	(06/02/2015)
Staley Solar, LLC	SP-4463, SUB 0	(03/03/2015)
Starr Farm, LLC	SP-5816, SUB 0	(11/17/2015)
Swift Creek Farm, LLC	SP-6088, SUB 0	(11/17/2015)
Tate Solar, LLC	SP-5045, SUB 0	(06/23/2015)
Terrell Solar Farm, LLC	SP-4714, SUB 0	(06/02/2015)
Thigpen Farms Solar, LLC	SP-4661, SUB 0	(12/15/2015)
Thomas Solar 2, LLC	SP-3834, SUB 43	(01/26/2015)
	SP-4469, SUB 0	
Tolson Solar, LLC	SP-5594, SUB 0	(07/28/2015)
Toprak LLC	SP-4708, SUB 0	(02/03/2015)
Trinity Solar, LLC	SP-5637, SUB 0	(07/28/2015)
Tripple State Farm, LLC	SP-3443, SUB 0	(12/08/2015)
Tubbs Farm, LLC	SP-4531, SUB 0	(12/15/2015)
Wadesboro Farm 2, LLC	SP-4558, SUB 0	(02/10/2015)
Walkulla Solar Farm, LLC	SP-4059, SUB 0	(05/27/2015)
Warrenton Solar 1, LLC	SP-4446, SUB 0	(01/28/2015)

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ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
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Company	Docket No.	Date
Warrenton Solar 2, LLC	SP-3834, SUB 30 SP-4445, SUB 0	(02/10/2015)
Warwick Solar, LLC	SP-4902, SUB 0	(02/25/2015)
Westwood Farm, LLC	SP-6478, SUB 0	(11/03/2015)
White Farm Solar, LLC	SP-2363, SUB 16 SP-4471, SUB 0	(02/10/2015)
White Street Renewables LLC	SP-4640, SUB 0	(05/27/2015)
Whiteville Solar 1, LLC	SP-5577, SUB 0	(06/30/2015)
Whitt Town Solar, LLC	SP-5971, SUB 0	(11/17/2015)
Wildcat Solar Farm, LLC	SP-5343, SUB 0	(05/27/2015)
Wilfork Solar, LLC	SP-5051, SUB 0	(09/21/2015)
Williams Solar Farm, LLC	SP-4060, SUB 0	(05/19/2015)
Wilson Solar Farm 3, LLC	SP-5393, SUB 0	(06/02/2015)
Wilson Solar Farm 4, LLC	SP-5392, SUB 0	(06/02/2015)
Wilson Solar Farm 5, LLC	SP-5391, SUB 0	(06/02/2015)
Wilson Solar Farm 6, LLC	SP-5390, SUB 0	(06/02/2015)
Wilson Solar Farm 7, LLC	SP-5389, SUB 0	(05/27/2015)
Wire Grass Solar, LLC	SP-4866, SUB 0	(03/16/2015)
Wortham Solar Farm, LLC	SP-4056, SUB 0	(05/27/2015)
ZV Solar 2, LLC	SP-3834, SUB 2 SP-4291, SUB 0	(01/26/2015)
ZV Solar 3, LLC	SP-3834, SUB 4 SP-4289, SUB 0	(02/25/2015)

Bladenboro Farm 2, LLC -- SP-2921, SUB 0; Order Issuing Amended Certificate and Accepting Registration of New Renewable Energy Facility (02/25/2015)

Moyock Solar, LLC -- SP-5309, SUB 0; Order Issuing Certificate of New Renewable Energy Facility (12/01/2015)

Solar Noir, LLC -- SP-1204, SUB 0; Order Issuing Certificate and Accepting Amended Registration of New Renewable Energy Facility (09/21/2015)

Spring Valley Farm 2, LLC -- SP-3919, Sub 0; Order Issuing Amended Certificate and Accepting Registration of New Renewable Energy Facility (08/11/2015)

Sweetgum Solar, LLC -- SP-3756, SUB 0; Errata Order (03/12/2015)

Williamston Speight Solar, LLC -- SP-5374, SUB 0; Order Issuing Certificate of New Renewable Energy Facility (08/11/2015)

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SMALL POWER PRODUCERS – Filings Due Per Order or Rule

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Company	Docket No.	Date
ABCZ Solar, LLC	SP-716, SUB 2	(01/23/2015)
Albertson Solar, LLC	SP-3777, SUB 0	(07/22/2015)
American Proteins, Inc.	SP-3816, SUB 0	(12/16/2015)
Asheville Alternative Energy, LLC	SP-5573, SUB 0	(09/11/2015)
Ashok & Mary Iyer	SP-3029, SUB 0	(03/31/2015)
Aspen Solar, LLC	SP-3428, SUB 0	(04/30/2015)
Balsam Solar, LLC	SP-3758, SUB 0	(04/30/2015)
Beaufort Solar, LLC	SP-2403, SUB 0	(07/27/2015)
Bernhardt Furniture Company	SP-5231, SUB 0	(08/21/2015)
Bioenergy Technologies of Berkeley County, LLC	SP-6247, SUB 0	(09/23/2015)
Blackberry Creek Family Partners, LLC	SP-4843, SUB 0	(02/13/2015)
Blythe & Hannah Ardyson	SP-3553, SUB 0	(05/20/2015)
California Energy Dairy #1, LLC	SP-3714, SUB 0	(01/06/2015)
California Energy Dairy #4, LLC	SP-3715, SUB 0	(03/31/2015)
California Energy Dairy 14, LLC	SP-5016, SUB 0	(07/27/2015)
Catawba Solar, LLC	SP-5155, SUB 0	(11/12/2015)
Cedar Solar, LLC	SP-3295, SUB 0	(04/30/2015)
Charity Solar Farm, LLC	SP-7104, SUB 0	(11/25/2015)
Choco Solar, LLC	SP-3775, SUB 0	(03/31/2015)
City of Wilmington	SP-420, SUB 3	(03/31/2015)
Clinton Solar, LLC	SP-4639, SUB 0	(02/10/2015)
Coastal Beverage Company, Inc.	SP-3062, SUB 1	(06/01/2015)
	SP-3062, SUB 2	(06/01/2015)
	SP-3062, SUB 3	(06/01/2015)
	SP-3062, SUB 4	(06/01/2015)
Colonial Eagle Solar, LLC	SP-4305, SUB 3	(09/11/2015)
	SP-4305, SUB 4	(11/12/2015)
Country Oak Solar Farm, LLC	SP-5145, SUB 0	(05/29/2015)
CREE, Inc.	SP-4597, SUB 0	(04/30/2015)
Dan Schnitzer	SP-4066, SUB 1	(05/29/2015)
Daniela & Thomas Doyle	SP-4927, SUB 0	(08/12/2015)
Dave Minnich	SP-4929, SUB 0	(08/12/2015)
Discovery Solar, LLC	SP-6951, SUB 0	(11/25/2015)
Doubs Chapel Solar, LLC	SP-6380, SUB 0	(12/14/2015)

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Company	Docket No.	Date
Eagle's Nest Solar LLC	SP-4789, SUB 0	(05/29/2015)
Elm Solar, LLC	SP-3754, SUB 0	(04/30/2015)
ESA Erwin NC, LLC	SP-4806, SUB 0	(06/01/2015)
ESA Four Oaks 2 NC, LLC	SP-5936, SUB 0	(09/25/2015)
ESA Goldsboro NC, LLC	SP-5174, SUB 0	(05/29/2015)
ESA Goldsboro NC Phase 2, LLC	SP-5254, SUB 0	(03/25/2015)
ESA Henderson 2, LLC	SP-5152, SUB 0	(11/25/2015)
ESA Kinston NC, LLC	SP-5239, SUB 0	(08/21/2015)
ESA Marshville NC, LLC	SP-6529, SUB 0	(10/07/2015)
Estes Express Lines, Inc.	SP-3880, SUB 1	(10/07/2015)
Farmer Ed, LLC	SP-6020, SUB 1	(09/25/2015)
	SP-6020, SUB 2	(09/25/2015)
Gantts Grove Church Road, LLC	SP-5031, SUB 0	(08/28/2015)
George R. McManus	SP-3983, SUB 0	(02/13/2015)
Gettysburg Energy and Nutrient Recovery Facility, LLC	SP-5858, SUB 0	(07/30/2015)
Graham Avenue Solar, LLC	SP-2236, SUB 0	(04/30/2015)
Green Creek Vineyards, LLC	SP-2446, SUB 1	(04/02/2015)
Green Heron Solar, LLC	SP-4608, SUB 0	(08/21/2015)
Grover Innovative Solar Park, LLC	SP-3275, SUB 1	(11/25/2015)
GTP 3, LLC	SP-4841, SUB 0	(01/23/2015)
Harvest Solar 1, LLC	SP-4001, SUB 1	(02/13/2015)
HCE Moore I, LLC	SP-5650, SUB 0	(11/12/2015)
Hickory Solar, LLC	SP-3755, SUB 0	(04/30/2015)
Highland Brewing Company, Inc.	SP-4349, SUB 0	(02/13/2015)
Horner Siding Solar Farm, LLC	SP-5122, SUB 0	(06/01/2015)
Howell Midland Farm, LLC	SP-3378, SUB 0	(12/16/2015)
Innovative Solar 16, LLC	SP-2697, SUB 0	(12/17/2015)
Innovative Solar 32, LLC	SP-5410, SUB 0	(09/11/2015)
Innovative Solar 35, LLC	SP-5411, SUB 0	(11/12/2015)
Innovative Solar 51, LLC	SP-5412, SUB 0	(11/13/2015)
Innovative Solar 56, LLC	SP-5907, SUB 0	(09/11/2015)
Innovative Solar 59, LLC	SP-5413, SUB 0	(08/12/2015)
Innovative Solar 60, LLC	SP-5419, SUB 0	(10/09/2015)
Irwin Creek, LLC	SP-5883, SUB 0	(09/11/2015)
James P. Miller	SP-4535, SUB 0	(04/14/2015)
JD Stuber	SP-5108, SUB 0	(11/12/2015)
Jersey Holdings LLC	SP-7017, SUB 0	(12/21/2015)

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Company	Docket No.	Date
Jewel Solar, LLC	SP-4788, SUB 0	(02/13/2015)
Jewels Realty Investment, LLC	SP-631, SUB 7	(04/13/2015)
Jim Stramler	SP-2408, SUB 0	(03/25/2015)
John D. Godfrey	SP-3081, SUB 1	(02/19/2015)
John Messenheimer	SP-4184, SUB 0	(06/17/2015)
Keith Cormier	SP-6052, SUB 0	(11/25/2015)
Landmark Solar Farm, LLC	SP-5095, SUB 0	(06/17/2015)
Laurinburg Solar, LLC	SP-2968, SUB 0	(03/31/2015)
Ledge Creek Solar, LLC	SP-5876, SUB 0	(08/28/2015)
Lincoln A. Baxter	SP-3101, SUB 0	(03/31/2015)
Lucky Clays Farm, LLC	SP-2962, SUB 0	(06/01/2015)
	SP-2962, SUB 1	(04/14/2015)
	SP-2962, SUB 2	(04/14/2015)
	SP-2962, SUB 3	(04/14/2015)
Lux Solar I, LLC	SP-4599, SUB 0	(04/14/2015)
Lynda Haberer	SP-6230, SUB 0	(12/14/2015)
Mark & Janet Hosey	SP-2811, SUB 0	(03/31/2015)
Mark Mautner	SP-5138, SUB 0	(06/18/2015)
Maverick Solar 1, LLC	SP-6950, SUB 0	(12/14/2015)
Max Planck Solar, LLC	SP-4606, SUB 0	(08/12/2015)
Maxton Solar Two, LLC	SP-4090, SUB 0	(01/26/2015)
Megan Lynch	SP-5574, SUB 0	(06/17/2015)
Merlin Solar, LLC	SP-6949, SUB 0	(12/14/2015)
Michael Allen Johnson	SP-6179, SUB 0	(12/14/2015)
Midway Power, LLC	SP-4683, SUB 0	(02/13/2015)
Mount Olive Solar LLC	SP-2041, SUB 0	(07/22/2015)
Mule Farm Solar, LLC	SP-5738, SUB 0	(09/25/2015)
Nashville Solar LLC	SP-4568, SUB 0	(07/27/2015)
Northern Cardinal Solar, LLC	SP-4607, SUB 0	(04/30/2015)
Old Caroleen Solar Farm, LLC	SP-5080, SUB 0	(06/01/2015)
Onslow County Farmers Market, Inc.	SP-1236, SUB 0	(07/22/2015)
Osborne Brothers Electric, Inc.	SP-3825, SUB 0	(02/13/2015)
Paul Anthony McInerney	SP-1960, SUB 0	(04/02/2015)
Paul & Claudine Cremer	SP-3034, SUB 0	(03/31/2015)
Pinedale Springs, LLC	SP-5400, SUB 2	(09/17/2015)
Poplar Solar, LLC	SP-3757, SUB 0	(04/30/2015)
Railroad Farm 2, LLC	SP-1918, SUB 0	(02/10/2015)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCERS – Filings Due Per Order or Rule *(Continued)*

ORDER ACCEPTING REGISTRATION OF
NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Red Toad Phase 2 Cleveland Road, LLC	SP-5246, SUB 0	(05/29/2015)
Red Toad Powhatan Phase 2, LLC	SP-5195, SUB 0	(10/09/2015)
Red Toad 243 Mort Harris Road, LLC	SP-5306, SUB 0	(04/02/2015)
Red Toad 699 Price Road, LLC	SP-4416, SUB 0	(01/29/2015)
Red Toad 901 Lynch Road, LLC	SP-4417, SUB 0	(01/29/2015)
Red Toad 1425 A Powatan Road, LLC	SP-4418, SUB 0	(01/29/2015)
Red Toad 3195 Buffalo Road, LLC	SP-4419, SUB 0	(01/29/2015)
Red Toad 4188 Cleveland Road, LLC	SP-4420, SUB 0	(09/11/2015)
Rocky Cross Solar, LLC	SP-4637, SUB 0	(05/29/2015)
Rosewood Solar, LLC	SP-6938, SUB 0	(11/19/2015)
Rowan Solar, LLC	SP-5154, SUB 0	(11/12/2015)
Roy Bernd Tebbe	SP-4567, SUB 0	(03/25/2015)
Ruskin Solar, LLC	SP-7100, SUB 0	(12/14/2015)
SAIA Motor Freight Line, LLC	SP-3630, SUB 1	(04/30/2015)
Sanchez 18 Solar, LLC	SP-5235, SUB 0	(06/01/2015)
Scarlet Solar, LLC	SP-5772, SUB 0	(07/22/2015)
Snow Hill Solar, LLC	SP-2317, SUB 1	(07/22/2015)
Solar Noir, LLC	SP-1204, SUB 0	(09/21/2015)
Spring Valley Lake Solar, LLC	SP-4944, SUB 0	(02/13/2015)
Sugar Creek WWTP, LLC	SP-5884, SUB 0	(09/17/2015)
Sumter Heat & Power, LLC	SP-5380, SUB 0	(12/15/2015)
Sundown Solar, LLC	SP-6937, SUB 0	(11/19/2015)
SunEnergy1-Scotland Neck, LLC	SP-3303, SUB 0	(06/01/2015)
The Rock Solar Energy Plant, LLC	SP-1652, SUB 0	(01/23/2015)
Town of Warsaw Solar Farm, LLC	SP-4128, SUB 0	(07/27/2015)
Triangle Realty Investment, LLC	SP-630, SUB 11	(04/13/2015)
	SP-630, SUB 12	(04/13/2015)
TWC Administration LLC	SP-5136, SUB 0	(06/01/2015)
Unadilla Solar, LLC	SP-4747, SUB 0	(01/23/2015)
United Shiloh Solar, LLC	SP-4937, SUB 0	(12/28/2015)
Vivid Solar I, LLC	SP-5097, SUB 0	(03/25/2015)
Wallace Solar 2, LLC	SP-4646, SUB 0	(02/10/2015)
Washington Millfield Solar, LLC	SP-2970, SUB 0	(01/20/2015)
White Cross Solar LLC	SP-4803, SUB 0	(05/29/2015)
Wilmington Solar, LLC	SP-4638, SUB 0	(04/29/2015)
Wyse Fork Solar Farm, LLC	SP-7065, SUB 0	(11/25/2015)
231 Dixon 74 Solar I, LLC	SP-4610, SUB 0	(04/30/2015)

SMALL POWER PRODUCERS – Filings Due Per Order or Rule *(Continued)*

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
232 Long Branch 29 Solar I, LLC	SP-4652, SUB 0	(02/10/2015)
233 Randolph 74 Solar I, LLC	SP-4619, SUB 0	(04/29/2015)
234 Williamston WF Solar I, LLC	SP-5661, SUB 0	(06/17/2015)

Shelby Randolph Road Solar 1, LLC -- SP-2385, SUB 1; Order Amending Registration of New Renewable Energy Facility (02/05/2015)
Sweetgum Solar, LLC -- SP-3756, SUB 0; Order Amending Registration of New Renewable Energy Facility (03/12/2015)
Weyerhaeuser NR Company -- SP-2285, SUB 0; Order Accepting Registration of Incremental Capacity as a New Renewable Energy Facility (07/21/2015)

ORDER ALLOWING WITHDRAWAL OF APPLICATION AND CLOSING DOCKET(S)
Orders Issued

Company	Docket No.	Date
Biggs Solar, LLC	SP-5340, SUB 0	(06/01/2015)
Birch Solar, LLC	SP-3429, SUB 0	(01/06/2015)
Boonville Solar, LLC	SP-5363, SUB 0	(06/01/2015)
Braswell Solar, LLC	SP-5333, SUB 0	(06/01/2015)
Bullard Solar, LLC	SP-5218, SUB 0	(06/01/2015)
Culpepper Farm, LLC	SP-3970, SUB 0	(12/11/2015)
Cypress Solar, LLC	SP-3411, SUB 0	(01/06/2015)
Frieden Church Solar, LLC	SP-5257, SUB 0	(08/31/2015)
Garnet Solar, LLC	SP-5063, SUB 0	(03/18/2015)
Geo Bryan LLC	SP-4170, SUB 0	(02/23/2015)
Glebe Solar Farm, LLC	SP-4058, SUB 0	(06/01/2015)
Goins Solar Farm, LLC	SP-3175, SUB 0	(10/09/2015)
GTOP Merritt LLC	SP-4171, SUB 0	(02/23/2015)
GTOP Merritt Solar Equities	SP-4996, SUB 0	(06/26/2015)
Hamlet Solar, LLC	SP-3047, SUB 0	(02/23/2015)
Helios Solar, LLC	SP-5046, SUB 0	(06/26/2015)
Jackson Solar Farm, LLC	SP-3658, SUB 0	(07/23/2015)
Johnston Solar I, LLC	SP-2426, SUB 1	(01/06/2015)
Littleton Phipps Solar, LLC	SP-4063, SUB 0	(02/23/2015)
Lumberton Solar 1, LLC	SP-5317, SUB 0	(06/01/2015)
Lumberton Solar 2, LLC	SP-5451, SUB 0	(06/26/2015)
Martin Solar Farm, LLC	SP-3030, SUB 0	(06/01/2015)

SMALL POWER PRODUCERS – Filings Due Per Order or Rule *(Continued)*

ORDER ALLOWING WITHDRAWAL OF APPLICATION AND CLOSING DOCKET(S)
Orders Issued *(Continued)*

Company	Docket No.	Date
McLean Solar, LLC	SP-4945, SUB 0	(03/18/2015)
Merritt Energy Partners, LLC	SP-4173, SUB 0	(07/07/2015)
Mial Plantation Solar Farm, LLC	SP-1869, SUB 0	(06/01/2015)
New Bern Solar, LLC	SP-5489, SUB 0	(06/01/2015)
Pear Tree Solar, LLC	SP-5634, SUB 0	(07/23/2015)
Pine Solar, LLC	SP-5256, SUB 0	(08/26/2015)
Pruitt Solar 1, LLC	SP-4401, SUB 0	(06/26/2015)
Pruitt Solar 2, LLC	SP-4400, SUB 0	(06/26/2015)
Raeford Jordan Farm, LLC	SP-5897, SUB 0	(09/17/2015)
Red Oak Solar, LLC	SP-4670, SUB 0	(01/26/2015)
Sassafras Solar, LLC	SP-3285, SUB 0	(03/18/2015)
Saturn Power Corporation	SP-4480, SUB 3	(09/16/2015)
Seventh Solar, LLC	SP-5450, SUB 0	(06/01/2015)
Siler City Solar, LLC	SP-5500, SUB 0	(06/26/2015)
Silver Birch Solar, LLC	SP-5633, SUB 0	(12/11/2015)
Smith Solar, LLC	SP-5332, SUB 0	(06/01/2015)
Son Power LLC	SP-4172, SUB 0	(06/26/2015)
Tarboro Northern Solar, LLC	SP-4355, SUB 0	(08/26/2015)
Teague Solar, LLC	SP-4784, SUB 0	(10/15/2015)
Timberlake Solar Farm, LLC	SP-5703, SUB 0	(08/31/2015)
Webb Solar, LLC	SP-5449, SUB 0	(06/01/2015)
Wesleyan Solar, LLC	SP-4787, SUB 0	(06/01/2015)
6-Acre Field LLC	SP-4176, SUB 0	(07/07/2015)

Conrad Energy, LLC -- SP-1396, SUB 0; SP-1396, SUB 1; Order Allowing Withdrawal of Report and Registration and Closing Docket (07/07/2015)

Langdon Solar Farm, LLC -- SP-3591, SUB 0; Order Allowing Construction of Erosion and Sedimentation Control Measures with Conditions (08/25/2015)

Payne Solar, LLC -- SP-5049, SUB 0; Order Allowing Withdrawal of Application and Registration Statement and Closing Docket (04/13/2015)

West Salisbury Farm, LLC -- SP-3251, SUB 0; Order Approving Land Addition to Facility Site (05/01/2015)

SMALL POWER PRODUCERS – Filings Due Per Order or Rule *(Continued)*

ORDER ALLOWING WITHDRAWAL OF APPLICATION, CANCELLING CPCN AND CLOSING DOCKET
Orders Issued

Company	Docket No.	Date
Bill Bryan Solar, LLC	SP-5328, SUB 0	(06/02/2015)
Bizzell Church Solar 3, LLC	SP-4322, SUB 0	(01/07/2015)
Bradley Farm, LLC	SP-3941, SUB 0	(06/02/2015)
Carolina Solar Energy II, LLC	SP-2363, SUB 7	(03/18/2015)
Carthage Solar, LLC	SP-4773, SUB 0	(06/24/2015)
Cattail Solar, LLC	SP-3813, SUB 0	(12/11/2015)
Clark Mountain Solar, LLC	SP-4333, SUB 0	(10/15/2015)
Coggins Solar, LLC	SP-4335, SUB 0	(09/24/2015)
Duck Solar, LLC	SP-2564, SUB 0	(06/24/2015)
Faison Farm, LLC	SP-3659, SUB 0	(07/23/2015)
Goins Solar, LLC	SP-5330, SUB 0	(05/28/2015)
GTP 2, LLC	SP-4842, SUB 0	(06/24/2015)
Hawkins Solar, LLC	SP-2690, SUB 0	(07/29/2015)
Hereford Holdings, LLC	SP-3888, SUB 0	(06/02/2015)
LaGrange Solar 1, LLC	SP-4321, SUB 0	(03/18/2015)
LaGrange Solar 2, LLC	SP-4320, SUB 0	(03/18/2015)
Manford Solar, LLC	SP-4653, SUB 0	(09/24/2015)
Molly Branch Solar, LLC	SP-5064, SUB 0	(05/28/2015)
Oxford Solar 2, LLC	SP-4404, SUB 0	(06/24/2015)
Piper Solar, LLC	SP-5060, SUB 0	(08/10/2015)
Prease Farm Solar, LLC	SP-4475, SUB 0	(01/07/2015)
Red Mountain Solar, LLC	SP-5186, SUB 0	(06/02/2015)
Shadow Solar, LLC	SP-2567, SUB 0	(07/29/2015)
SoINCPower4, LLC	SP-3035, SUB 0	(06/24/2015)
Spring Hope Solar, LLC	SP-4447, SUB 0	(06/24/2015)
St. Pauls Solar 3, LLC	SP-4398, SUB 0	(06/24/2015)
Warrenton Solar 2, LLC	SP-4445, SUB 0	(06/24/2015)

Maxton Solar 1, LLC -- SP-4287, SUB 0; Order Allowing Limited Construction with Conditions (10/29/2015)

Tracy Solar, LLC -- SP-3437, SUB 0; Order Allowing Construction of Erosion and Sedimentation Control Measures with Conditions (07/10/2015)

West Salisbury Farm, LLC -- SP-3251, SUB 0; Order Approving Land Addition to Facility Site (05/01/2015)

SMALL POWER PRODUCERS – Filings Due Per Order or Rule *(Continued)*

ORDER CANCELLING REGISTRATION AND CLOSING DOCKET
Orders Issued

Company	Docket No.	Date
Calypso Solar, LLC	SP-2042, SUB 0	(07/14/2015)
Castelow Solar, LLC	SP-3722, SUB 0	(05/28/2015)
Dixie-Marree Pricket	SP-3684, SUB 0	(07/13/2015)
Green Heron Solar, LLC	SP-4608, SUB 0	(10/07/2015)
Max Planck Solar, LLC	SP-4606, SUB 0	(10/06/2015)
McCaskey Solar Farm, LLC	SP-3322, SUB 0	(05/29/2015)
Onslow County Farmers Market, Inc.	SP-1236, SUB 0	(07/30/2015)
RES AG-DM 3-3, LLC	SP-1105, SUB 0	(10/09/2015)
RES AG-Melville 2, LLC	SP-1104, SUB 0	(10/09/2015)
Wilson Community College	SP-350, SUB 0	(03/06/2015)

Roy Bernd Tebbe -- SP-4567, SUB 0; Order Cancelling Registration Statement and Closing Docket (04/14/2015)

Sustainable Solar, LLC -- SP-2879, SUB 0; Order Cancelling Registration Statement and Closing Docket (04/13/2015)

ORDER CANCELLING REGISTRATION, CLOSING DOCKET, AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued

Company	Docket No.	Date
BAL Solar I, LLC	SP-760, SUB 0 SP-5587, SUB 9	(10/20/2015)
	SP-760, SUB 1 SP-5587, SUB 10	(10/21/2015)
	SP-760, SUB 2 SP-5587, SUB 11	(10/20/2015)
	SP-760, SUB 3 SP-5587, SUB 12	(10/21/2015)

SMALL POWER PRODUCERS – Filings Due Per Order or Rule *(Continued)*

ORDER CANCELLING REGISTRATION, CLOSING DOCKET, AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
BAL Solar II, LLC	SP-758, SUB 0	(10/21/2015)
	SP-5587, SUB 0	
	SP-758, SUB 1	(10/21/2015)
	SP-758, SUB 2	
	SP-758, SUB 3	(10/21/5015)
	SP-5587, SUB 3	
	SP-758, SUB 4	(10/21/2015)
	SP-5587, SUB 4	
	SP-758, SUB 5	(10/21/2015)
	SP-5587, SUB 5	
	SP-758, SUB 6	(10/21/2015)
	SP-5587, SUB 6	
	SP-758, SUB 7	(10/21/2015)
	SP-5587, SUB 7	
	SP-758, SUB 8	(10/21/2015)
	SP-5587, SUB 8	

ORDER TRANSFERING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REGISTRATION
Orders Issued

Company	Docket No.	Date
Clark Brothers LLC	SP-3685, SUB 0	(04/10/2015)
	SP-5437, SUB 0	
Fresh Air Energy II, LLC	SP-2665, SUB 4	(01/06/2015)
	SP-4891, SUB 0	
	SP-2665, SUB 5	(01/06/2015)
	SP-4899, SUB 0	
	SP-2665, SUB 11	(01/06/2015)
	SP-4622, SUB 0	
	SP-2665, SUB 14	(01/06/2015)
	SP-4894, SUB 0	
	SP-2665, SUB 18	(01/06/2015)
	SP-4896, SUB 0	
	SP-2665, SUB 19	(01/27/2015)
	SP-4892, SUB 0	

SMALL POWER PRODUCERS – Filings Due Per Order or Rule *(Continued)*

ORDER TRANSFERING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REGISTRATION
Orders Issued *(Continued)*

Company	Docket No.	Date
Fresh Air Energy II, LLC	SP-2665, SUB 20 SP-4901, SUB 0	(01/06/2015)
	SP-2665, SUB 22 SP-4893, SUB 0	(01/27/2015)
	SP-2665, SUB 23 SP-4900, SUB 0	(01/26/2015)
	SP-2665, SUB 27 SP-4898, SUB 0	(12/11/2015)
	SP-2665, SUB 31 SP-4895, SUB 0	(01/27/2015)
	SP-2665, SUB 33 SP-4897, SUB 0	(01/26/2015)
Innovative Solar 34, LLC	SP-3475, SUB 0 SP-5189, SUB 0	(02/23/2015)
Mount Olive I, LLC	SP-3701, SUB 1 SP-5395, SUB 0	(03/26/2015)
	SP-3701, SUB 2 SP-5394, SUB 0	(03/26/2015)

Kelford Solar, LLC – SP-3209, SUB 0; SP-4305, SUB 3; Order Transfering Certificate of Public Convenience and Necessity (03/18/2015)

North Carolina Renewable Power – Lumberton -- SP-5640, SUB 0; Order on Transfer of Facilities and Certificates (04/28/2015)

SolarGreen Eco-Industrial Solar Park 1, LLC – SP-3545, SUB 0; SP-884, SUB 6; Order Transfering Certificate of Public Convenience and Necessity (12/11/2015)

SunEnergy1, LLC -- SP-751,
- SUB 13; SP-5081, SUB 0; Order Transferring Certificate of Public Convenience and Necessity (02/04/2015)
- SUB 19; SP-4305, SUB 4; Order Transfering Certificate of Public Convenience and Necessity (03/18/2015)
- SUB 21; SP-5082, SUB 0; Order Transferring Certificate of Public Convenience and Necessity (02/04/2015)

SMALL POWER PRODUCERS – Registration Statements

City of Greensboro -- SP-2105, SUB 0; Order Allowing Withdrawal of Report and Closing Docket (05/28/2015)

ORDERS AND DECISIONS LISTED

TELECOMMUNICATIONS

TELECOMMUNICATIONS – Cancellation of Certificate

ORDER CANCELING CERTIFICATE
Orders Issued

Company	Docket No.	Date
CSP Telecom, Inc.	P-1371, SUB 1	(12/16/2015)
Flatel, Inc.	P-1206, SUB 1	(03/03/2015)
Globalinx Enterprises, Inc.	P-776, SUB 1	(04/24/2015)
Network Operator Services, Inc.	P-722, SUB 3	(06/25/2015)
New Century Telecom, Inc.	P-660, SUB 3	(10/16/2015)
Reunion Communications, Inc.	P-1484, SUB 1	(05/29/2015)
Telenational Communication, Inc.	P-1183, SUB 1	(03/19/2015)
Utmost, Inc., A Communications Service Co.	P-583, SUB 2	(04/24/2015)
WDT World Discount Telecommunications Company	P-1196, SUB 1	(11/09/2015)
Yak Communications (America) Inc.	P-1238, SUB 1	(03/04/2015)

Cbeyond Communications, LLC -- P-1044, SUB 2; Order Canceling Certificates (05/14/2015)
Fidelity Communication Services III, Inc. -- P-1448, SUB 2; Order Canceling Certificates (08/05/2015)
Impact Telecom, Inc. -- P-1515, SUB 1; P-705, SUB 4; P-224, SUB 13; Order Cancelling Certificates (03/03/2015)
MegaPath Corporation -- P-775, SUB 10; Order Cancelling Certificates (02/27/2015)
PhoneAid Communications Corp. -- P-1530, SUB 2; Order Canceling Certificates (04/10/2015)
School Link, Inc. -- P-1250, SUB 2; Order Canceling Certificates (11/16/2015)

TELECOMMUNICATIONS -- Certificate

LOCAL CERTIFICATE
Orders Issued

Company	Docket No.	Date
Comporium, Inc.	P-1576, SUB 0	(10/13/2015)
RCLEC, Inc.	P-1574, SUB 0	(08/18/2015)
RiverStreet Communications of North Carolina, Inc.	P-1577, SUB 0	(11/16/2015)
SCTG Communications, Inc.	P-1573, SUB 0	(02/05/2015)
Wide Voice, LLC	P-1567, SUB 3	(07/24/2015)

TELECOMMUNICATIONS – Certificate *(Continued)*

LONG DISTANCE CERTIFICATE
Orders Issued

Company	Docket No.	Date
Dial World Communications, LLC	P-1503, SUB 2	(11/04/2015)
RCLEC, Inc.	P-1574, SUB 1	(03/11/2015)

TELECOMMUNICATIONS -- Contract/Agreements

ORDER APPROVING AGREEMENT(s) ***or***
ORDER APPROVING AMENDMENT(s)
Orders Issued

Barnardsville Telephone Company -- P-75, SUB 77; P-76, SUB 66; P-60, SUB 85 *(Saluda Mountain Telephone Co., Service Telephone Co. & Verizon Wireless)* (06/16/2015)

BellSouth Telecommunications, LLC – P-55,
SUB 1452 *(Business Telecom, Inc.)* (01/26/2015)
SUB 1460 *(Matrix Telecom, Inc.)* (03/10/2015)
SUB 1467 *(ACN Communication Services, Inc.)* (02/10/2015)
SUB 1521 *(Level 3 Communications, LLC)* (05/19/2015)
SUB 1526 *(T-Mobile USA, Inc.)* (06/16/2015)
SUB 1547 *(Carolina West Wireless, Inc.)* (01/26/2015)
SUB 1573 *(BCN Telecom, Inc.)* (01/26/2015)
SUB 1624 *(Momentum Telecom, Inc.)* (08/19/2015)
SUB 1631 *(AT&T Corp.)* (02/10/2015)
SUB 1634 *(Teleport Communications America, LLC)* (02/10/2015)
SUB 1637 *(Dialog Telecommunications, Inc.)* (01/26/2015)
SUB 1668 *(Access Point Inc.)* (01/26/2015)
SUB 1672 *(Global Crossing Local Services, Inc.)* (02/10/2015)
SUB 1674 *(Spectrotel, Inc.)* (03/10/2015)
SUB 1676 *(EarthLink Business, LLC)* (01/26/2015)
SUB 1726 *(tw telecom of north carolina, l.p.)* (03/10/2015); (07/21/2015)
SUB 1728 *(Global Connection, Inc. of America)* (02/10/2015)
SUB 1749 *(Birch Telecom of the South, Inc.)* (12/08/2015)
SUB 1758 *(Budget Prepay, Inc.)* (02/10/2015)
SUB 1770 *(Tele Circuit Network Corp.)* (03/10/2015)
SUB 1807 *(Bullseye Telecom, Inc.)* (03/10/2015)
SUB 1811 *(Springboard Telecom, LLC)* (02/10/2015)
SUB 1824 *(Wholesale Carrier Services, Inc.)* (03/10/2015)
SUB 1827 *(Broadview Networks, Inc.)* (03/10/2015)
SUB 1849 *(Business Telecom, LLC)* (01/26/2015)
SUB 1853 *(Rosebud Telephone, LLC)* (12/08/2015)
SUB 1870 *(OneTone Telecom, Inc.)* (01/26/2015)

TELECOMMUNICATIONS -- Contract/Agreements *(Continued)*

ORDER APPROVING AGREEMENT(s) ***or***
ORDER APPROVING AMENDMENT(s)
Orders Issued *(Continued)*

BellSouth Telecommunications, LLC – P-55, *(Continued)*
SUB 1902; SUB 1903; SUB 1904 *(Network Telephone Corp., The Other Phone Company, Inc., & Talk America, Inc.)* (03/10/2015)
SUB 1905 *(QuantumShift Communications, Inc.)* (05/19/2015)
SUB 1910 *(IP Spectrum Solutions, LLC)* (12/08/2015)
Carolina Telephone and Telegraph Co. LLC & Central Telephone Co. -- P-7,
SUB 1265 *(Teleport Communications America, LLC)* (06/16/2015)
SUB 1267; P-10, SUB 882 *(Sprint Communications)* (07/21/2015)
SUB 1268 *(New Cingular Wireless PCS, LLC)* (07/21/2015)
SUB 1270 *(AT&T Corp.)* (10/12/2015)
SUB 1271; P-10, SUB 885 *(Hypercube Telecom, LLC)* (12/08/2015)
SUB 1272; P-10, SUB 886 *(Tri-County Communications, Inc.)* (12/08/2015)
SUB 1273; P-10, SUB 887 *(Starvision, Inc.)* (12/08/2015)
Central Telephone Company -- P-10,
SUB 880 *(Teleport Communications America, LLC)* (06/16/2015)
SUB 884 *(AT&T Corp.)* (10/13/2015)
DeltaCom, LLC -- P-500,
SUB 10 *(BellSouth Telecommunications, LLC)* (12/08/2015)
SUB 18; P-500, SUB 18a *(BellSouth Telecommunications, LLC)* (01/26/2015)
MCIMetro Access Transmission Services, LLC -- P-474, SUB 14 *(BellSouth Telecommunications, LLC)* (05/19/2015)
MebTel, Inc. -- P-35,
SUB 130 *(Birch Communications)* (06/16/2015)
SUB 131 *(Teleport Communications America, LLC)* (06/16/2015)
SUB 132 *(Sprint Communications)* (07/21/2015)
SUB 133 *(QuantumShift Communications, Inc.)* (11/17/2015)
SUB 134 *(Hypercube Telecom, LLC)* (12/08/2015)
Verizon South, Inc. -- P-19, SUB 501 *(Charter FiberLink NC-CCO, LLC)* (01/26/2015)
Windstream Concord Telephone, LLC -- P-16,
SUB 261; P-31, SUB 167; P-118, SUB 196 *(Windstream Lexcom Communications, LLC, Windstream North Carolina, LLC & CenturyLink Communications, LLC)* (09/09/2015); Errata Order (09/10/2015)
SUB 262; P-31, SUB 168; P-118, SUB 197 *(Windstream Lexcom Communications, LLC, Windstream North Carolina, LLC & Bandwidth.com CLEC, LLC)* (12/08/2015)

<u>TELECOMMUNICATIONS -- Discontinuance</u>

Business Telecomm, LLC, d/b/a Earthlink Business -- P-165 Sub 41; Order Granting Petition to Discontinue Service (02/25/2015)

Cypress Communications Operating Company, LLC -- P-1027, SUB 4; Order Permitting Discontinuance of Services (04/14/2015)

<u>TELECOMMUNICATIONS -- Miscellaneous</u>

BellSouth Telecommunications, LLC – P-55,
SUB 1908; Order Granting Numbering Resources (06/16/2015)
SUB 1909; Order Granting Numbering Resources (06/16/2015)

Carolina Telephone and Telegraph Co. LLC & Central Telephone Co. -- P-7,
SUB 1266; P-10, SUB 881; Order Permitting CenturyLink to Abandon Enhanced Frame Relay Service (05/29/2015)
SUB 1274; Order Granting Numbering Resources (11/12/2015)

Frontier Communications of the Carolinas LLC -- P-1488, SUB 41; Order Granting Numbering Resources (04/24/2015)

North State Telephone Company -- P-42, SUB 137F; P-1210, SUB 1; Order Permitting Discontinuance of Certain Operator Services (04/09/2015)

Teleport Communications America, LLC -- P-1547,
SUB 3; Order Granting Numbering Resources (04/15/2015)
SUB 4; Order Granting Numbering Resources (12/14/2015)

Windstream Communications, Inc. -- P-1394, SUB 6; Order Granting Numbering Resources (06/01/2015)

Windstream North Carolina, LLC -- P-118, SUB 195; Order Granting Numbering Resources (05/21/2015)

<u>TELECOMMUNICATIONS – Sale/Transfer</u>

TDS Long Distance Corporation -- P-988, SUB 1; P-1280, SUB 2; Customer Transfer Order (03/11/2015)

<u>TELECOMMUNICATIONS – Tariff</u>

Verizon South Inc. -- P-19, SUB 542; Order Granting Petition to Discontinue the Provision of Certain Tariffed Services and Waiving Certain Requirements of Commission Rule R21-2 (01/28/2015)

ORDERS AND DECISIONS LISTED

TRANSPORTATION

TRANSPORTATION – Cancellation of Certificate

ORDER CANCELLING CERTIFICATE OF EXEMPTION
Orders Issued

Company	Docket No.	Date
Affordable Movers and Packers	T-4554, SUB 2	(06/30/2015)
Alternative Moving & Storage, LLC	T-4502, SUB 2	(01/06/2015)
Althletes Movers, Inc.	T-4507, SUB 2	(04/01/2015)
Keever Moving Service	T-4479, SUB 3	(01/21/2015)
Pro Relocation of the Carolinas, Inc.	T-4448, SUB 3	(08/13/2015)
Quick Moves, Inc.	T-4443, SUB 4	(08/19/2015)
Sandbridge Solutions, LLC	T-4559, SUB 1	(03/13/2015)
Worldwide Relocation Services, Inc.	T-4347, SUB 4	(08/13/2015)

Felicia King, d/b/a We're Moving -- T-4574, SUB 1; Recommended Order Cancelling Certificate of Exemption (12/11/2015)

Herbert E. Anderson, d/b/a Anderson Moving Co. -- T-4320, SUB 3; Recommended Order Cancelling Certificate of Exemption (07/13/2015)

Xtreme Moving & Storage, LLC, d/b/a Xtreme Moving -- T-4513, SUB 2; Recommended Order Cancelling Certificate of Exemption (01/09/2015)

TRANSPORTATION – Common Carrier Certificate

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION
Orders Issued

Company	Docket No.	Date
Abdulraouf Bassam Allamadani, d/b/a Best Bet Moving and Labor	T-4528, SUB 0	(02/19/2015)
Campbell's Moving, LLC	T-4592, SUB 0	(09/08/2015)
Carson Cornwell Gaines, d/b/a Tropical Moves	T-4598, SUB 0	(11/17/2015)
Charlie Powell's Model Moves, Inc.	T-4571, SUB 0	(04/27/2015)
Coo-Lee Enterprise, Inc., d/b/a Oh My! Movers	T-4573, SUB 0	(08/18/2015)
Custom Moving Solutions, LLC	T-4595, SUB 0	(09/14/2015)
Derric Pearce Fozard, d/b/a Apartment Movers Plus	T-4570, SUB 0	(06/10/2015)
Dwight Dion Williams, d/b/a Meek Movers	T-4569, SUB 0	(07/28/2015)
Felicia King, d/b/a We're Moving	T-4574, SUB 0	(06/29/2015)
Get It Home, LLC	T-4604, SUB 0	(12/08/2015)

TRANSPORTATION – Common Carrier Certificate *(Continued)*

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION
Orders Issued (Continued)

Company	Docket No.	Date
Guardian Transfer & Storage, LLC	T-4504, SUB 2	(08/07/2015)
Hardin Furniture Company	T-4602, SUB 0	(12/30/2015)
Jeff's Express, LLC	T-4403, SUB 2	(02/23/2015)
K And D Moving & Storage, Inc., d/b/a Two Men and a Truck	T-4594, SUB 0	(10/16/2015)
Let's Get Moving Services, LLC	T-4605, SUB 0	(12/30/2015)
Marathon Moving Company, Inc.	T-4590, SUB 0	(08/06/2015)
Metropolitan Moving, LLC	T-4607, SUB 0	(12/11/2015)
Movers 4 You, LLC	T-4579, SUB 0	(06/10/2015)
Pinehurst Moving & Storage Co., Inc.	T-4561, SUB 0	(04/13/2015)
Preferred Moving Company LLC	T-4583, SUB 0	(07/20/2015)
R & M Charlotte, LLC, d/b/a Two Men and A Truck of Charlotte	T-4558, SUB 0	(01/29/2015)
Sandbridge Solutions, LLC	T-4559, SUB 0	(01/23/2015)
Sandhills Moving & Storage, Co.	T-4562, SUB 0	(09/24/2015)
Southern Moving and Storage, LLC	T-4577, SUB 0	(06/02/2015)
Sparta Moving and Storage, LLC	T-4560, SUB 0	(01/08/2015)
Sustainable Alamance	T-4572, SUB 0	(06/17/2015)
Valor Moving Company, Inc.	T-4568, SUB 0	(04/28/2015)
1-800-Pack-Rat, LLC	T-4600, SUB 0	(11/19/2015)
4 Sons, Inc., d/b/a Cary Moving	T-4563, SUB 0	(04/06/2015)

Demetrius Cosby, d/b/a B&C Carriers Transport – T-4578, SUB 0; Order Denying Application and Closing Docket (09/08/2015)

Ernest Keith, Jr., d/b/a Mantruk -- T-4556, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (02/23/2015)

TRANSPORTATION – Complaint

Pick Up and Go Moving International -- T-4523, SUB 2; Order Dismissing Complaint and Closing Docket *(Maria Roawden)* (02/05/2015)

ORDERS AND DECISIONS LISTED

TRANSPORTATION – Name Change

East Coast Moving, LLC -- T-4242, SUB 5; Order Approving Name Change (10/20/2015)

Graebel/North Carolina Movers, Inc. -- T-2333, SUB 10; Order Approving Name Change (08/13/2015)

Juan Alvarado-Parra, d/b/a Me and My Team -- T-4544, SUB 1; Order Approving Name Change (06/22/2015)

Marrins' Moving System, Ltd. -- T-4329, SUB 5; Order Approving Name Change (06/03/2015)

Roeder & Moore, LLC, d/b/a Two Men and A Truck of Rock Hill -- T-3397, SUB 7; Order Approving Name Change (01/27/2015)

The Wes Stewart Corporation, d/b/a Stewart Moving and Storage -- T-4529, SUB 2; Order Approving Name Change (12/03/2015)

Weathers Brothers Moving and Storage Company, Inc. -- T-4114, SUB 6; Order Approving Name Change (05/20/2015)

TRANSPORTATION – Rate Schedules/Riders/Service Rules & Regulations

Rates/Truck -- T-825,

SUB 349; Order Approving Fuel Surcharge (01/05/2015)

SUB 350; Order Approving Fuel Surcharge (02/02/2015); (03/02/2015); (04/06/2015); (05/04/2015); (06/01/2015); (07/06/2015); (08/03/2015); (08/31/2015); (10/05/2015); (11/02/2015); (11/30/2015)

TRANSPORTATION – Sale/Transfer

Acme Movers & Storage Company, Inc. -- T-4575, SUB 0; T-880, SUB 10; Order Approving Sale and Transfer (05/11/2015)

Ballantyne & Beyond Moving, Inc. -- T-4564, SUB 0; T-4400, SUB 9; Order Approving Sale and Transfer (02/25/2015)

Bay Moving & Storage, Inc. -- T-4576, SUB 0; T-4425, SUB 5; Order Approving Sale and Transfer (05/11/2015)

Berkins A-1 Movers, Inc., d/b/a Coastline Relocation -- T-4586, SUB 0; T-4409,SUB 5; Order Approving Transfer (07/31/2015)

Berkins A-1 Movers, Inc., d/b/a Highland Moving and Storage Co. -- T-4587, SUB 0; T-4375, SUB 6; Order Approving Transfer (07/31/2015)

Graebel/North Carolina Movers, Inc. -- T-2333, SUB 8; Order Approving Stock Transfer (06/29/2015)

TRANSPORTATION – Show Cause

Christopher N. Wilhoit, d/b/a A Magic Move, Inc. -- T-4552, SUB 0; T-4510, SUB 2; Order Ruling Penalty Satisfied, Dismissing Proceeding, and Closing Dockets (07/30/2015)

TRANSPORTATION -- Suspension

Fleming-Shaw Transfer and Storage, Inc. -- T-60, SUB 4; Order Granting Authorized Suspension (01/16/2015)

Kenneth J. Scallions, d/b/a Ballantyne & Beyond Moving -- T-4400, SUB 8; Order Granting Authorized Suspension (02/09/2015); Order Rescinding Order Granting Authorized Suspension (02/10/2015)

WATER AND SEWER

WATER AND SEWER – Bonding

A&D Water Service, Inc. -- W-1049, SUB 20; Order Approving Bond and Surety and Releasing Bond and Surety (05/29/2015)

Harkers Island Sewer Company, LLC -- W-1297, SUB 5; Order Approving Bond and Surety and Releasing Bond and Surety (08/03/2015)

Old North State Water Company, LLC -- W-1300, SUB 12; Order Approving Bond and Surety and Releasing Bond (03/16/2015)

WATER AND SEWER – Certificate

Aqua North Carolina, Inc. -- W-218,

SUB 396; Order Granting Franchise and Approving Rates (02/02/2015)

SUB 402; Order Granting Franchise and Approving Rates (08/21/2015)

SUB 408; W-1149, SUBS 8 & 9; Order Allowing Recommended Order to Become Effective and Final (08/10/2015); Recommended Order Approving Partial Rate Increase and Requiring Customer Notice (11/16/2015); Order Allowing Recommended Order to Become Effective and Final (11/16/2015)

Harkers Island Sewer Company, LLC -- W-1297, SUB 3; Order Granting Franchise, Approving Rates, and Requiring Customer Notice (09/28/2015)

Pluris, LLC -- W-1282,

SUB 12; Order Granting Franchise, Approving Rates, and Requiring Customer Notice (06/19/2015)

SUB 13; Order Authorizing Pledge of Assets and Loan (08/11/2015)

Water Resource Management, Inc. -- W-1073, SUB 4; Order Accepting and Approving Bond, Granting Franchise, Approving Rates, and Requiring Customer Notice (12/16/2015)

WATER AND SEWER – Complaint

CS Land Holding, LLC -- W-354, SUB 339; Order Dismissing Complaint and Closing Docket *(Carolina Water Service, Inc.)* (03/19/2015)

ORDERS AND DECISIONS LISTED

WATER AND SEWER – Discontinuance

Aqua North Carolina, Inc. -- W-218, SUB 411; Order Canceling Franchise (11/30/2015)

Holly Springs Golf and Country Club, Ltd. – W-944, SUB 1; Order Canceling Franchise (05/21/2015)

WATER AND SEWER – Emergency Operator

Environmental, Inc. -- W-760, SUB 1; Recommended Order Approving Rate Increase and Assessment and Requiring Customer Notice (01/20/2015)

WATER AND SEWER – Filings Due Per Order or Rule

Aqua North Carolina, Inc. -- W-218,

SUB 319A; Order Terminating Annual Reporting Requirement (03/10/2015)

SUB 363A; Order Approving Secondary Water Quality Improvement Projects (05/21/2015); Order Approving Water and Sewer System Improvement Charges on a Provisional Basis and Requiring Customer Notice (06/23/2015); Order Approving Secondary Water Quality Improvement Projects (08/20/2015)

Carolina Water Service, Inc. -- W-354, SUB 336A; Order Approving Water and Sewer System Improvement Charges on a Provisional Basis, And Requiring Customer Notice (03/24/2015)

ORDER RECOGNIZING CONTIGUOUS EXTENSION

Orders Issued

Company	Docket No.	Date
Aqua North Carolina, Inc.		
(North Village Subdivision)	W-218, SUB 360	(06/23/2015)
(Avocet Subdiv., Phases 1C, 1D, & 1E)	W-218, SUB 378	(02/02/2015)
(Chacewater Subdivision)	W-218, SUB 380	(02/02/2015)
(Hasentree Subdivision, Phase 10)	W-218, SUB 398	(02/02/2015)
(Hasentree Subdivision, Phase 4A)	W-218, SUB 401	(02/02/2015)
(Avocet Subdivision, Phase 2)	W-218, SUB 403	(06/23/2015)
(Bells Crossing Subdiv., Phases 3 & 4)	W-218, SUB 404	(04/29/2015)
(Sweetgrass Subdivision)	W-218, SUB 405	(04/29/2015)
(Legacy at Jordan Lake Subdiv., Ph. 4A)	W-218, SUB 406	(06/23/2015)
(Legacy at Jordan Lake Subdiv., Ph. 5A)	W-218, SUB 407	(06/23/2015)
(Hasentree Subdivision, Phase 4B)	W-218, SUB 409	(06/23/2015)
(South Quarter Subdivision)	W-218, SUB 412	(06/23/2015)

WATER AND SEWER – Filings Due Per Order or Rule *(Continued)*

Enviracon Utilities, Inc. -- W-1236, SUB 5; Order Recognizing Contiguous Extension and Approving Rates (10/09/2015)

Harkers Island Sewer Company, LLC -- W-1297, SUB 1; Order Granting Franchise, Approving Rates, and Requiring Customer Notice *(By the Bay Subdivision, Phase 1)* (08/03/2015)

ORDER APPROVING TARIFF REVISION AND REQUIRING REFUND

Orders Issued

Company	Docket No.	Date
A & D Water Service, Inc.	W-1049, SUB 19 M-100, SUB 138	(10/12/2015)
Albemarle Plantation Utility Company, Inc.	W-1189, SUB 3 M-100, SUB 138	(02/13/2015)
Bay Tree Utility Company	W-1080, SUB 1 M-100, SUB 138	(02/13/2015)
Baytree Waterfront Properties, Inc.	W-938, SUB 5 M-100, SUB 138	(10/14/2015)
Beacon's Reach Master Association, Inc.	W-966, SUB 4 M-100, SUB 138	(10/12/2015)
Bear Den Acres Development Inc.	W-1040, SUB 8 M-100, SUB 138	(10/12/2015)
Blue Creek Utilities, Inc.	W-857, SUB 8 M-100, SUB 138	(10/12/2015)
Briar Chapel Utilities, LLC	W-1230, SUB 2 M-100, SUB 138	(02/13/2015)
Britthaven Utilities, Inc.	W-1015, SUB 1 M-100, SUB 138	(02/13/2015)
Clarke Utilities, LLC	W-1205, SUB 8 M-100, SUB 138	(10/12/2015)
Conleys Creek Limited Partnership	W-1120, SUB 7 M-100, SUB 138	(10/12/2015)
Corriher Water Service	W-233, SUB 25 M-100, SUB 138	(10/14/2015)
Deerfield Shores Utilities Company, Inc.	W-925, SUB 2 M-100, SUB 138	(10/12/2015)
Dutchman Creek, Inc.	W-1082, SUB 5 M-100, SUB 138	(10/12/2015)
Earth Environmental Services, d/b/a; Michael Joel Ladd	W-1129, SUB 4 M-100, SUB 138	(02/13/2015)
Enviro-Tech of North Carolina, Inc.	W-1165, SUB 4 M-100, SUB 138	(10/13/2015)
Fairfield Water Company	W-1226, SUB 2 M-100, SUB 138	(02/13/2015)

WATER AND SEWER – Filings Due Per Order or Rule *(Continued)*

ORDER APPROVING TARIFF REVISION AND REQUIRING REFUND
Orders Issued *(Continued)*

Company	Docket No.	Date
Fearrington Utilities	W-661, SUB 8 M-100, SUB 138	(10/13/2015)
Flat Creek Utilities, LLC	W-1272, SUB 2 M-100, SUB 138	(02/13/2015)
GGCC Utility, Inc.	W-755, SUB 8 M-100, SUB 138	(10/13/2015)
High Hampton Inc.	W-574, SUB 3 M-100, SUB 138	(10/13/2015)
Horse Creek Farms Utilities Corp.	W-888, SUB 5 M-100, SUB 138	(02/13/2015)
JACABB Utilities, LLC	W-1298, SUB 1 M-100, SUB 138	(02/13/2015)
John T. Billingsley, et al.	W-632, SUB 5 M-100, SUB 138	(10/12/2015)
John W. Gensinger	W-549, SUB 9 M-100, SUB 138	(10/13/2015)
Joyceton Water Works, Inc.	W-4, SUB 18 M-100, SUB 138	(10/13/2015)
JPC Utilities, LLC	W-1263, SUB 1 M-100, SUB 138	(02/13/2015)
KDHWWTP, L.L.C.	W-1160, SUB 24 M-100, SUB 138	(10/13/2015)
KRJ Utilities Company	W-1075, SUB 10 M-100, SUB 138	(10/13/2015)
Linville Heights, L.P.	W-1137, SUB 3 M-100, SUB 138	(10/13/2015)
Maxwell Water Company	W-339, SUB 6 M-100, SUB 138	(10/13/2015)
Meadowlands Development, LLC	W-1259, SUB 4 M-100, SUB 138	(04/02/2015)
Mountain Air Utilities Corp.	W-1148, SUB 11 W-1148, SUB 12 M-100, SUB 138	(04/06/2015)
Mountain View Park, LLC	W-1089, SUB 6 M-100, SUB 138	(10/13/2015)
Old North State Water Company, LLC	W-1300, SUB 11 M-100, SUB 138	(02/13/2015)
Outer Banks/Kinnakeet Associates, LLC	W-1125, SUB 7 M-100, SUB 138	(10/13/2015)

WATER AND SEWER – Filings Due Per Order or Rule *(Continued)*

ORDER APPROVING TARIFF REVISION AND REQUIRING REFUND
Orders Issued *(Continued)*

Company	Docket No.	Date
Overhills Water Company, Inc.	W-175, SUB 13 M-100, SUB 138	(10/13/2015)
Pace Utilities Group, Inc.	W-1046, SUB 2 W-1046 SUB 3 M-100, SUB 138	(04/29/2015)
Piedmont Water & Sewer, LLC	W-1294, SUB 3 M-100, SUB 138	(10/13/2015)
Pine Island-Currituck LLC	W-1072, SUB 16 M-100, SUB 138	(10/13/2015)
Pines Utilities, Inc.	W-822, SUB 1 M-100, SUB 138	(02/13/2015)
Ponderosa Enterprises, Inc.	W-1086, SUB 3 M-100, SUB 138	(10/13/2015)
Prior Construction Co.	W-567, SUB 7 M-100, SUB 138	(10/13/2015)
Riverbend Water System, Inc.	W-390, SUB 12 M-100, SUB 138	(10/13/2015)
Rock Creek Environmental Company, Inc.	W-830, SUB 5 M-100, SUB 138	(10/14/2015)
Rolesville MHP, LLC	W-1270, SUB 1 M-100, SUB 138	(02/13/2015)
Royal Palms Water and Sewer System	W-1105, SUB 3 M-100, SUB 138	(10/14/2015)
Saxapahaw Utility Company	W-1250, SUB 5 M-100, SUB 138	(03/06/2015)
Scientific Water and Sewer Corp.	W-176, SUB 39 M-100, SUB 138	(11/18/2015)
Total Environmental Solutions, Inc.	W-1146, SUB 11 M-100, SUB 138	(10/14/2015)
Vila Pump Company	W-945, SUB 3 M-100, SUB 138	(02/13/2015)
Water Qualities, Inc.	W-1264, SUB 4 M-100, SUB 138	(02/13/2015)
Water Resource Management, Inc.	W-1073, SUB 5 M-100, SUB 138	(02/13/2015)
Water Resources, Inc.	W-1034, SUB 7 M-100, SUB 138	(10/14/2015)
Water Works of Alamance County, Inc.	W-1149, SUB 7 M-100, SUB 138	(02/13/2015)

WATER AND SEWER – Filings Due Per Order or Rule *(Continued)*

ORDER APPROVING TARIFF REVISION AND REQUIRING REFUND
Orders Issued *(Continued)*

Company	Docket No.	Date
Webb Creek Water & Sewage, Inc.	W-864, SUB 9 M-100, SUB 138	(10/15/2015)
Whispering Pines Village, d/b/a John D. Hock	W-1042, SUB 6 M-100, SUB 138	(10/14/2015)
William Edward Cook, Jr.	W-1262, SUB 1 M-100, SUB 138	(10/12/2015)
Woods Water Works, Inc.	W-735, SUB 4 M-100, SUB 138	(10/14/2015)
904 Georgetown Treatment Plant, LLC	W-1141, SUB 6 M-100, SUB 138	(10/12/2015)

Aqua North Carolina, Inc. -- W-218,
SUB 272; Order Approving Tariff Revision and Requiring Customer Notice *(Chapel Ridge, Laurel Ridge, & The Parks at Meadowview)* (08/20/2015)
SUB 395; Order Recognizing Contiguous Extension and Approving Rates *(River Oaks Subdivision, Section 8, Phase 1)* (08/21/2015)
SUB 397; Order Recognizing Contiguous Extension and Approving Rates *(Chatham Subdivision, Phases 1B & 2)* (02/02/2015)
SUB 399; Order Recognizing Contiguous Extension and Approving Rates *(Beau Rivage Apts. Subdivision)* (11/30/2015)
SUB 410; Order Recognizing Contiguous Extension and Approving Rates *(Evergreen Subdivision, Phase I)* (11/30/2015)
SUB 414; Order Recognizing Contiguous Extension and Approving Rates *(River Dell East Subdivision, Phase I)* (11/30/2015)
SUB 416; Order Recognizing Contiguous Extension and Approving Rates *(Heather Glen Subdivision)* (11/30/2015)
SUB 417; Order Recognizing Contiguous Extension and Approving Rates *(The Village at Motts Landing Subdivision)* (11/30/2015)
SUB 418; Order Recognizing Contiguous Extension and Approving Rates *(Hawthorne Park Subdivision)* (11/30/2015)
SUB 419; Order Recognizing Contiguous Extension and Approving Rates *(Tralee Place Subdivision)* (11/30/2015)

Dry Ridge Properties, LLC -- W-1299, SUB 1; M-100, SUB 138; Order Approving Tariff Revision, Suspending Refund, and Requiring Report (10/08/2015)

YES AF Utilities EXP, LLC -- W-1302, SUB 2; M-100, SUB 138; Order Approving Tariff Revision, Suspending Refund, and Requiring Report (10/08/2015)

ORDERS AND DECISIONS LISTED

WATER AND SEWER – Rate Increase

Bradfield Farms Water Company -- W-1044 SUB 21; Order Approving Stipulation, Granting Rate Increase, and Requiring Customer Notice (03/27/2015)

Christmount Christian Assembly, Inc. -- W-1079, SUB 14; Order Granting Rate Increase and Requiring Customer Notice (05/21/2015)

Ridgecest Water Utility -- W-71, SUB 11; Recommended Order Granting Rate Increase and Requiring Customer Notice (12/22/2015)

Sugarloaf Utility, Inc. -- W-1154, SUB 7; Recommended Order Granting Rate Increase and Requiring Customer Notice (07/02/2015); Order Allowing Recommended Order to Become Effective and Final (07/09/2015)

WATER AND SEWER – Sale/Transfer

Aqua North Carolina, Inc. -- W-218, SUB 421; Order Approving Transfer to Owner Exempt from Regulation, Canceling Franchises, and Requiring Customer Notice (12/16/2015)

Old North State Water Company, LLC -- W-1300, SUB 9; W-1230 SUB 1; Recommended Order Approving Transfer, Granting Franchise, Approving Rates and Requiring Customer Notice (04/20/2015); Order Allowing Recommended Order to Become Effective and Final (04/20/2015)

WATER AND SEWER – Securities

Aqua North Carolina, Inc. -- W-218, SUB 422; Order Approving Issuance of Note Payable (11/13/2015)

WATER AND SEWER – Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION

Orders Issued

Company	Docket No.	Date
Chatham Utilities, Inc. *(Chatham Estates Manuf. Housing Comm.)*	W-1240, SUB 11	(07/27/2015)
Christmount Christian Assembly, Inc. *(Christmount Christian Assembly & Subdiv.)*	W-1079, SUB 15	(07/27/2015)

ORDERS AND DECISIONS LISTED

WATER AND SEWER – Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Dillsboro Water and Sewer, Inc. *(BP/Subway, Holiday Inn Express, DRA Living Hotel & Dillsboro Crossing Apts.)*	W-1303, SUB 2	(11/30/2015)
Greenfield Heights Development Co. *(Greenfield Heights Subdivision)*	W-205, SUB 7	(08/11/2015)
Harkers Island Sewer Company, LLC	W-1297, SUB 4 M-100, SUB 138	(02/19/2015)
IA Matthews Sycamore, LLC, d/b/a Inland American Mgmt., LLC *(Sycamore Commons)*	W-1304, SUB 1	(01/20/2015)
MECO Utilities, Inc. *(Mobile Estates Mobile Home Park)*	W-1166, SUB 13	(09/08/2015)
Town and Country Mobile Home Park *(Town and Country Mobile HP)*	W-1193, SUB 9	(10/12/2015)

Watercrest Estates -- W-1021, SUB 11; Order Approving Tariff Revision and Requiring Customer Notice *(Watercrest Estates MHP)* (07/27/2015)

WATER RESELLERS

WATER RESELLERS – Cancellation of Certificate

ORDER CANCELING CERTIFICATE OF AUTHORITY
Orders Issued

Company	Docket No.	Date
ACG Greensboro, LLC *(Cranbrook Village Mobile Home Park)*	WR-1344, SUB 1	(08/24/2015)
Advenir@Monroe 5920, LLC *(Advenir at Monroe 5920 Apartments)*	WR-511, SUB 5	(01/20/2015)
AMFP I Hamilton Ridge, LLC *(Hamilton Ridge Apartments)*	WR-805, SUB 8	(11/25/2015)

WATER RESELLERS – Cancellation of Certificate *(Continued)*

ORDER CANCELING CERTIFICATE OF AUTHORITY
Orders Issued *(Continued)*

Company	Docket No.	Date
AMFP II Four Seasons, LLC *(Four Seasons at Umstead Park Apts.)*	WR-1165, SUB 4	(03/23/2015)
Beckanna Partners, LLC *(Beckanna on Glenwood Apartments)*	WR-1460, SUB 3	(04/06/2015)
Bouwfonds Pavilion Crossings I, LLC *(Pavilion Crossings I Apartments)*	WR-599, SUB 7	(01/05/2015)
Bouwfonds Pavilion Crossings II, LLC *(Pavilion Crossings II Apartments)*	WR-598, SUB 7	(01/05/2015)
Camden Operating, LP *(Camden Habersham Apartments)*	WR-42, SUB 72	(01/12/2015)
CH Realty IV/Notting Hill, LLC *(Notting Hill Apartments)*	WR-852, SUB 4	(05/18/2015)
CMS Thornhill, LP *(Thornhill Apartments)*	WR-401, SUB 4	(07/27/2015)
Cornelia Rosca *(Lynrock Apartments)*	WR-697, SUB 2	(06/15/2015)
Corsica Forest Apartment Associates, LLC *(Tryon Park at Rivergate Apts.)*	WR-1595, SUB 1	(10/07/2015)
Crescent Main Street Venture, LLC *(Crescent Main Street Apartments)*	WR-1744, SUB 1	(09/02/2015)
Crescent Ninth Street Venture I, LLC *(Crescent Ninth Street Apartments)*	WR-1653, SUB 1	(02/02/2015)
CSP Lexington Farms, LLC *(Lexington Farms Apartments)*	WR-1269, SUB 2	(05/12/2015)
Epoch Highland Park Investment Partners, LLC *(Highland Park at Northlake Apts.)*	WR-1589, SUB 1	(12/08/2015)
Estates Holdings, LLC *(Courtney Estates Apartments)*	WR-572, SUB 8	(09/30/2015)
Fairfield BCMR Centerview, LLC *(The Villas at Centerview Apts.)*	WR-829, SUB 2	(10/21/2015)
Foxrun Ridge Limited Partnership *(Ridge Run Apartments)*	WR-146, SUB 3	(12/07/2015)
JLB Elizabeth, LLC *(Venue Apartments)*	WR-1549, SUB 1	(02/10/2015)
Joslin Realty, Inc. *(Grove Park Apartments)*	WR-151, SUB 10	(12/29/2015)
Kip-Dell Homes, Inc. *(Clover Lane Townehomes)*	WR-341, SUB 8	(11/18/2015)
Landmark at Lynden Square, LP *(Lankmark at Lynden Square Apts.)*	WR-1483, SUB 1	(08/13/2015)

WATER RESELLERS – Cancellation of Certificate *(Continued)*

ORDER CANCELING CERTIFICATE OF AUTHORITY
Orders Issued *(Continued)*

Company	Docket No.	Date
LVP Timber Creek, LLC	WR-717, SUB 8	(02/24/2015)
(Beacon Timber Creek Apartments)		
Madison Properties, Inc.	WR-1380, SUB 6	(03/25/2015)
(673 Sand Hill Road Apartments)		
MB Remington Place, LLC	WR-461, SUB 9	(07/14/2015)
(Remington Place Apartments)		
MB The Timbers, LLC	WR-462, SUB 9	(07/14/2015)
(The Timbers Apartments)		
Mission Durham LeaseCo., LLC		
(Mission University Pines Apartments)	WR-804, SUB 2	(09/16/2015)
(Mission Triangle Point Apartments)	WR-804, SUB 3	(09/23/2015)
Mission Matthews Place LeaseCo, LLC	WR-858, SUB 3	(10/27/2015)
(Mission Matthews Place Apts.)		
MP Creekwood, LLC	WR-738, SUB 7	(06/08/2015)
(Village Lakes Apartments)		
MP Cross Creek, LLC	WR-736, SUB 7	(03/30/2015)
(Sardis Place at Matthews Apartments)		
MP Hunt Club, LLC	WR-735, SUB 7	(07/02/2015)
(Hunt Club Apartments)		
MP The Oaks, LLC	WR-734, SUB 7	(03/30/2015)
(The Oaks Apartments)		
MP The Point, LLC	WR-733, SUB 7	(07/02/2015)
(The Pointe Apartments)		
MP The Regency, LLC	WR-740, SUB 7	(07/02/2015)
(The Regency Apartments)		
MP Winterwood, LLC	WR-739, SUB 7	(07/02/2015)
(Aspen Peak Apartments)		
MRP Laurel Oaks, LLC	WR-507, SUB 5	(03/16/2015)
(Laurel Oaks Apartments)		
MRP Laurel Springs, LLC	WR-506, SUB 6	(03/16/2015)
(Laurel Springs Apartments)		
Northlake Residential Associates, LLC	WR-1361, SUB 2	(02/16/2015)
(Madison Square at Northlake Apts.)		
Northwoods Apartments, LLC	WR-1495, SUB 1	(11/03/2015)
(Northwoods Townhomes Apts., Phase I)		
ORP Lynnwood Park, LLC	WR-1186, SUB 4	(03/09/2015)
(Lynnwood Park Apartments)		
Princeton Park Apartments, LLC	WR-541, SUB 11	(01/26/2015)
(Legacy North Hills Apartments)		

WATER RESELLERS – Cancellation of Certificate *(Continued)*

ORDER CANCELING CERTIFICATE OF AUTHORITY
Orders Issued *(Continued)*

Company	Docket No.	Date
RAIA Self-Storage Montville, LLC, et al. *(The Enclave at Crossroads Apartments)*	WR-890, SUB 10	(09/08/2015)
RES-Dewberry Properties, LLC *(Bent Oaks Apartments)*	WR-956, SUB 1	(03/02/2015)
Ridge Apartments, LLC *(The Ridges Apartments)*	WR-1350, SUB 1	(10/14/2015)
Sagebrush Andover Woods Apartments, LLC *(Andover Woods Apartments)*	WR-1571, SUB 3	(11/19/2015)
Sagebrush Courtney Oaks Apartments, LLC *(Courtney Oaks Apartments)*	WR-567, SUB 5	(05/26/2015)
SBC 2013-1 REO 105832, LLC *(Hanover Landing Apartments)*	WR-1531, SUB 1	(07/06/2015)
SG-Waterford-Morrisville, LLC *(The Waterford Apartments)*	WR-1157, SUB 5	(11/10/2015)
Six Forks Apartments, LLC *(Bainbridge Six Forks Apartments)*	WR-1596, SUB 1	(08/17/2015)
Steele Creek Charlotte Associates, LLC *(Sterling Steele Creek Apartments)*	WR-1449, SUB 1	(08/06/2015)
Summermill Properties, LLC *(Summermill at Falls River Apartments)*	WR-395, SUB 7	(04/21/2015)
Suncoast Cornerstone, LLC, et al. *(Cornerstone Apartments)*	WR-801, SUB 7	(04/27/2015)
Suncoast North Park, LLC *(North Park Apartments)*	WR-808, SUB 7	(04/14/2015)
Tremont Partners, LP *(Ashton Southend Apartments)*	WR-963, SUB 2	(05/05/2015)
Village Creek West Properties I, LLC, et al. *(Village Creek West Apartments)*	WR-713, SUB 3	(12/22/2015)
VTT Durham, LLC *(Foxfire Apartments)*	WR-998, SUB 3	(06/01/2015)
Waterford Lakes Partners, LLC *(Waterford Lakes Apartments)*	WR-731, SUB 5	(07/02/2015)
Wellington United, LLC *(Wellington Farms Apartments)*	WR-1527, SUB 2	(07/21/2015)
Westdale Beech Lake, LLC *(Beech Lake Apartments)*	WR-1213, SUB 4	(06/22/2015)
401 Oberlin, LLC *(401 Oberlin Apartments)*	WR-1657, SUB 1	(03/09/2015)

ORDERS AND DECISIONS LISTED

WATER RESELLERS – Certificate

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
AB Merion II Thornhill, LLC	WR-1867, SUB 0	(07/27/2015)
(Thornhill Apartments)		
Adeline at White Oak, LLC	WR-1740, SUB 0	(03/03/2015)
(Adeline at White Oak Apartments)		
AERC Alpha Mill Lane, LP		
(Alpha Mill (Phase 1) Apartments)	WR-1649, SUB 2	(01/20/2015)
(Alpha Mill (Phase 2) Apartments)	WR-1649, SUB 3	(01/20/2015)
AERC Lofts Lakeside, LP	WR-1586, SUB 2	(01/20/2015)
(Lofts at Weston Apartments)		
AERC St. Mary's, LP		
(St Mary's Square Apartments)	WR-1587, SUB 2	(01/20/2015)
(St. Mary's Square Apartments)	WR-1587, SUB 3	(10/07/2015)
Ansley Roberts Lake Apartments, LLC	WR-1804, SUB 0	(04/21/2015)
(Ansley at Roberts Lake Apartments)		
Apex Road Commercial, LLC	WR-1896, SUB 0	(09/11/2015)
(Phillips Chatham Pointe Apts., Phase II)		
ARIM Crossroads, LLC	WR-1748, SUB 0	(01/26/2015)
(Crossroads North Hills Apartments)		
Arium McAlpine Creek Owner, LLC	WR-1790, SUB 0	(04/07/2015)
(Arium McAlpine Creek Apartments)		
Arium Pineville LL, LLC	WR-1760, SUB 0	(02/23/2015)
(Arium Pineville Apartments)		
ARWC – 808 Lakecrest Avenue, LLC	WR-1969, SUB 0	(12/29/2015)
(Chatham Woods Apartments)		
Asheville Housing, LLC	WR-1916, SUB 0	(10/20/2015)
(Evolve Mountain View Apartments)		
Ashton Oaks Partnership, Ltd.	WR-1840, SUB 0	(06/22/2015)
(Ashton Oaks Apartments)		
AVR Davis Raleigh, LLC	WR-1813, SUB 0	(04/29/2015)
(Jones Grant Urban Flats Apartments)		
Bavarian Village, LLC	WR-1828, SUB 0	(05/27/2015)
(Bavarian Village Apartments)		
Beachwood II Associates, LLC	WR-1824, SUB 0	(05/18/2015)
(Loch Raven Pointe Apartments)		
Belle Meade Development Partners, LLC	WR-1942, SUB 0	(11/18/2015)
(Belle Meade Apartments)		
BMPP Main Street L. P.	WR-1891, SUB 0	(09/02/2015)
(Berkshire Main Street Apartments)		
BMPP Ninth Street L. P.	WR-1779, SUB 0	(03/25/2015)
(Crescent Ninth Street Apartments)		

ORDERS AND DECISIONS LISTED

WATER RESELLERS – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
Brentwood Apartments of Mooresville, LLC *(Ridgeview Apartments)*	WR-1875, SUB 0	(08/13/2015)
Bridford Parkway Apartments, LLC *(Hawthorne at Bridford Apts., Phase III)*	WR-1363, SUB 3	(09/30/2015)
Camden Glen, LLC *(Emerson Glen Apartments)*	WR-1913, SUB 0	(10/14/2015)
Camden USA, LLC *(Camden Gallery Apartments)*	WR-1836, SUB 0	(06/08/2015)
CCC Caliber Chase, LLC *(Calibre Chase Apartments)*	WR-1886, SUB 0	(08/25/2015)
CCC Forest at Biltmore Park, LLC, et al. *(Forest at Biltmore Park Apartments)*	WR-1742 SUB 0	(01/26/2015)
CCC Olde Raleigh, LLC *(Olde Raleigh Apartments)*	WR-1814, SUB 0	(05/04/2015)
CCC Summerlin Ridge, LLC *(Summerlin Ridge Apartments)*	WR-1805, SUB 0	(04/28/2015)
Chatham Mill Ventures, LLC *(Mill 800 Apartments)*	WR-1951, SUB 0	(12/01/2015)
City Block Apartments, LLC *(City Block Apartments, Phase I)*	WR-1764, SUB 0	(03/09/2015)
City View Commercial, LLC *(City View at Southside Apts., Phase III)*	WR-1236, SUB 4	(02/17/2015)
Clemmons Town Center Apartments, LLC *(Clemmons Towncenter Apartments)*	WR-1756, SUB 0	(02/17/2015)
Clover Lane, LLC *(Mordecai on Clover Apartments)*	WR-1941, SUB 0	(11/18/2015)
Concord-Empire Davie Street, LLC *(Davie Street Apartments)*	WR-1757, SUB 0	(02/17/2015)
Courtney NC, LLC *(Oakwood Raleigh at Brier Creek Apts.)*	WR-1908, SUB 0	(09/30/2015)
Courtney Oaks Apartments, LLC *(Courtney Oaks Apartments)*	WR-1884, SUB 0	(09/14/2015)
CPGPI Still Meadow, LLC *(Still Meadow Apartments, Phases I & II)*	WR-1889, SUB 0	(09/02/2015)
Crescent Main Street Venture, LLC *(Crescent Main Street Apartments)*	WR-1744, SUB 0	(01/20/2015)
Crescent South Park Venture I, LLC *(Crescent South Park Apartments)*	WR-1895, SUB 0	(09/11/2015)
Cross Point NC Partners, LLC *(Sardis Place at Matthews Apartments)*	WR-1851, SUB 0	(07/02/2015)

WATER RESELLERS – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued (Continued)

Company	Docket No.	Date
DPR Centerview, LLC	WR-1958, SUB 0	(12/07/2015)
(Centerview at Crossroads Apartments)		
East 54 Associates, LLC	WR-1752, SUB 0	(02/10/2015)
(East 54 Apartments)		
Eco Watercourse, LLC	WR-1880, SUB 0	(08/21/2015)
(Watercourse Apartments)		
Edward Rose Millennial Development, LLC	WR-1935 SUB 0	(11/04/2015)
(Avellan Springs Apartments)		
Eighty-Six North, LLC	WR-1643, SUB 2	(12/07/2015)
(86 North Apartments)		
Elan Raleigh Property, LLC	WR-1928, SUB 0	(10/28/2015)
(Elan City Center Apartments)		
Ellington Farms Apartments, LLC	WR-1900, SUB 0	(09/25/2015)
(Ellington Farms Apartments)		
Enclave at Crossroads, LLC	WR-1922, SUB 0	(10/21/2015)
(Enclave at Crossroads Apartments)		
FCP West Village Phase III, LLC	WR-1751, SUB 0	(02/17/2015)
(West Village Apartments, Phase III)		
Federal Home Apex, LLC	WR-1929, SUB 0	(10/28/2015)
(West Haven Apartments)		
Federal Home Naples Terrace, LLC	WR-1956, SUB 0	(12/07/2015)
(Naples Terrace Apartments)		
Fieldstone Partners, LLC	WR-1749, SUB 0	(02/02/2015)
(Fieldstone Villas Apartments)		
Flat Creek Village Apartments, LLC	WR-1964, SUB 0	(12/21/2015)
(Flat Creek Village Apartments)		
Franklin Ventures V, LLC	WR-1939, SUB 0	(11/18/2015)
(The Franklin Apartments)		
Free Throw NC Partners, LLC	WR-1855, SUB 0	(07/02/2015)
(The Pointe Apartments)		
Fund Southline, LLC	WR-1789, SUB 0	(04/07/2015)
(Camden Southline Apartments)		
G Colonial, LLC		
(Empire Crossing Apartments)	WR-1829, SUB 0	(05/27/2015)
(Colonial Apts., Phases 5 & 6)	WR-1829, SUB 1	(11/24/2015)
Glenhaven G, LLC	WR-1873, SUB 0	(08/13/2015)
(Glen Haven Apartments, Phase 3)		
Glenhaven K, LLC	WR-1872, SUB 0	(08/13/2015)
(Glen Haven Apartments, Phase 1 & 2)		

WATER RESELLERS – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
Glenwood Raleigh Apartments, LLC	WR-1833, SUB 0	(05/27/2015)
(Sterling Glenwood Apartments)		
Glenwood South Raleigh Apartments, LLC	WR-1877, SUB 0	(08/19/2015)
(Link Glenwood South Apartments)		
Golden Triangle #4-5th Street, LLC	WR-1809, SUB 0	(04/29/2015)
(Diggs on Sixth Apartments)		
Governours Square Club, LLC	WR-1842, SUB 0	(06/23/2015)
(Governours Square Apartments)		
Grays Land Apartments, LLC	WR-1927, SUB 0	(10/28/2015)
(Hawthorne at the Grove Apartments)		
Greenway at Stadium Park, LLC	WR-1909, SUB 0	(10/08/2015)
(Greenway at Stadium Park Apartments)		
Gregory Scott Cogdill	WR-1925, SUB 0	(10/27/2015)
(Springside Mobile Home Park)		
Half Penny Sparrows, LLC	WR-1961, SUB 0	(12/15/2015)
(Daystar Mobile Home Park)		
Hamilton Ridge Property Corp.	WR-1946, SUB 0	(11/25/2015)
(Hamilton Ridge Apartments)		
Hart's Mobile Home Park, Inc.	WR-1786, SUB 0	(04/07/2015)
(Hart's Mobile Home Park)		
Hawthorne-Charleston Strickland, LLC, LLC	WR-1778, SUB 0	(03/25/2015)
(Hawthorne Glen at Strickland Apartments)		
Hawthorne-Midway Bear Creek, LLC	WR-1899, SUB 0	(09/24/2015)
(Hawthorne at Bear Creek Apartments)		
Heritage Andover I, LLC, et al.	WR-1959, SUB 0	(12/11/2015)
(Andover Woods Apartments)		
Heritage Pointe NC Partners, LLC	WR-1852, SUB 0	(07/02/2015)
(Hunt Club Apartments)		
HRTBH Timber Creek, LLC	WR-1761, SUB 0	(02/24/2015)
(Timber Creek Apartments)		
Hunt Hill Apartments, LLC	WR-1920, SUB 0	(10/21/2015)
(The Retreat at Hunt Hill Apartments)		
Jack Ryan, LLC	WR-1777, SUB 0	(03/25/2015)
(673 Sand Hill Road Apartments)		
JLB Southpark Apartments, LLC	WR-1832, SUB 0	(05/27/2015)
(Allure Apartments)		
John N Bakatsias	WR-1898, SUB 0	(09/23/2015)
(Mebane Mobile Home Park)		
Johnston Road Apartments, LLC	WR-1849, SUB 0	(07/02/2015)
(Element Apartments)		

WATER RESELLERS – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
K Colonial, LLC	WR-1943, SUB 0	(11/24/2015)
(Colonial Apartments, Phase 3)		
KC Realty Investments, LLC		
(Glimmer Mobile Home Park)	WR-950, SUB 6	(04/21/2015)
(Oteen Mobile Home Park)	WR-950, SUB 9	(12/22/2015)
Keystone at Walkertown Landing, LLC	WR-1917, SUB 0	(10/20/2015)
(Keystone at Walkertown Landing Apts.)		
Kings Arms, LLC	WR-1874, SUB 0	(08/13/2015)
(Kings Arms Apartments)		
Lancaster GCI, LLC, et al.	WR-1879, SUB 0	(08/21/2015)
(Legacy 521 Apartments)		
LCP Durham, LLC	WR-1914, SUB 0	(10/15/2015)
(Foxfire Apartments)		
Lincoln Apartments, LLC	WR-1912, SUB 0	(10/14/2015)
(The Lincoln Apartments)		
LMI-South Kings Development, LLC	WR-1866, SUB 0	(07/27/2015)
(Midtown 205 Apartments)		
LNHN – Northwoods Townhomes NC, LLC	WR-1918, SUB 0	(10/20/2015)
(Northwoods Townhomes Apts., Phase I)		
Lockwood Village Apartments, LLC	WR-1775, SUB 0	(03/24/2015)
(Lockwood Village Apartments)		
Lynnwood Gardens Associates, LLC	WR-1972, SUB 0	(12/30/2015)
(Lynnwood Park Apartments)		
M Station, LLC	WR-1844, SUB 0	(06/23/2015)
(M Station Apartments)		
Mardel Holdings, LLC		
(151 Weaverville Road Apartments)	WR-1755, SUB 0	(02/10/2015)
(64 Beverly Road Apartments)	WR-1755, SUB 1	(02/10/2015)
(186 New Haw Creek Road Apartments)	WR-1755, SUB 2	(02/10/2015)
(65 Old Haw Creek Road Apartments)	WR-1755, SUB 3	(02/10/2015)
MCP Ashton South End, LLC	WR-1819, SUB 0	(05/05/2015)
(Ashton Southend Apartments)		
Melrose Condos, Inc.	WR-1871, SUB 0	(08/13/2015)
(Melrose Apartments)		
Mercury NoDa Apartments, LLC	WR-1954, SUB 0	(12/01/2015)
(Mercury NoDa Apartments)		
Midtown Apartment Homes, LLC	WR-1793, SUB 0	(05/11/2015)
(One Midtown Apartments)		

WATER RESELLERS – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
Misty Oaks NC Partners, LLC	WR-1856, SUB 0	(07/02/2015)
(The Oaks Apartments)		
MLVI Pointe at Crabtree Apartments, LLC	WR-1796, SUB 0	(04/14/2015)
(The Pointe at Crabtree Apartments)		
Morganton Park, LLC	WR-1831, SUB 0	(05/27/2015)
(Legends at Morganton Apartments)		
New Garden Square, LLC	WR-1766, SUB 0	(05/18/2015)
(New Garden Square Apartments)		
North Carolina Land Lease, LLC	WR-1965, SUB 0	(12/22/2015)
(Cranbrook Village Mobile Home Park)		
North Chase Apts., LLC	WR-1821, SUB 0	(05/12/2015)
(North Chase Apartments)		
Northlake Investors 288, LLC	WR-1208, SUB 3	(05/04/2015)
(Ashton Reserve at Northlake Apts., Ph. 2)		
Northlake Madison Properties, LLC, et al.	WR-1807, SUB 0	(04/21/2015)
(Madison Square Apartments)		
Notting Hill Owner, LLC	WR-1839, SUB 0	(06/15/2015)
(Notting Hill Apartments)		
NP Six Forks, LLC	WR-1948, SUB 0	(11/25/2015)
(Junction Six Forks Apartments)		
NR Holly Crest Property Owner, LLC	WR-1816, SUB 0	(05/04/2015)
(Holly Crest Apartments)		
NR Morningside Property Owner, LLC	WR-1903, SUB 0	(09/29/2015)
(Village on Commonwealth Apartments)		
Park 2300 Apartments, LLC	WR-1835, SUB 0	(06/08/2015)
(Park 2300 Apartments)		
Pavilion Village, LLC	WR-1932, SUB 0	(11/04/2015)
(Pavilion Village Apartments)		
PEG Chapel Hill, I, LLC	WR-1641, SUB 2	(12/07/2015)
(The Apartments at Midtown 501)		
Penrith Townhomes, LLC	WR-1763, SUB 0	(03/04/2015)
(Woodland Creek Apartments)		
Pfalzgraf Communities 8, LLC	WR-1797, SUB 0	(04/14/2015)
(Teal Point Apartments)		
Piedmont Place Apts. Property Investors, LLC	WR-1801, SUB 0	(04/20/2015)
(Piedmont Place Apartments)		
Piper Station Apartments, LLC		
(Rock Creek at Ballantyne Apts., Phase II)	WR-1432, SUB 4	(12/07/2015)
(Rock Creek at Ballantyne Commons Apts.)	WR-1432, SUB 5	(12/21/2015)

WATER RESELLERS – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
Plantation at Fayetteville, LLC *(Plantation at Fayetteville Apartments)*	WR-1768, SUB 0	(03/23/2015)
Plantation at Pleasant Ridge, LLC *(Plantation at Pleasant Ridge Apts.)*	WR-1767, SUB 0	(03/04/2015)
PR II DRP Parkside, LLC *(Parkside Place Apartments)*	WR-1803, SUB 0	(04/21/2015)
PRG Falls at Duraleigh Associates, LLC *(The Falls Apartments)*	WR-1800, SUB 0	(04/20/2015)
Residences at Brookline, LLC *(Residences at Brookline Apartments)*	WR-1915, SUB 0	(10/15/2015)
Rivergate Apartment Investors, LLC *(Tryon Park at Rivergate Apartments)*	WR-1926, SUB 0	(10/28/2015)
ROC II NC Pavilion Crossing, LLC *(Pavilion Crossings Apartments)*	WR-1808, SUB 0	(04/28/2015)
RRE Farrington Holdings, LLC *(Farrington Lake Apartments)*	WR-1870, SUB 0	(08/12/2015)
Ryder Downs, LLC *(Ryder Downs Apartments)*	WR-1830, SUB 0	(05/27/2015)
SBMF Phase 3, LLC *(Stillwater at Southbridge Apartments)*	WR-1883, SUB 0	(08/24/2015)
SCG/TBR Venue Owner, LLC *(Venue Apartments)*	WR-1799, SUB 0	(05/05/2015)
Simpson Woodfield Marshall Park *(Marshall Park Apartments)*	WR-1864, SUB 0	(07/21/2015)
Skyhouse Charlotte, LLC *(Skyhouse Charlotte Apartments)*	WR-1919, SUB 0	(10/21/2015)
Skyhouse Raleigh, LLC *(Skyhouse Raleigh Apartments)*	WR-1784, SUB 0	(04/06/2015)
Somerset Park, LLC *(Somerset Mobile Home Park)*	WR-1826, SUB 0	(05/18/2015)
Stephens Pointe, LLC *(Stephens Pointe Apartments)*	WR-1746, SUB 0	(01/26/2015)
Stoney Brook Apartments Limited Partnership *(Stoney Brook Apartments)*	WR-1848, SUB 0	(06/30/2015)
Summermill at Falls River Apartments *(Summermill at Falls River Apartments)*	WR-1892, SUB 0	(09/02/2015)
Summit Street, LLC *(District Flats Apartments)*	WR-1741, SUB 0	(01/13/2015)
Sustainable Properties, LLC *(Pine Grove Mobile Home Park)*	WR-1933, SUB 0	(11/04/2015)

WATER RESELLERS – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued (Continued)

Company	Docket No.	Date
TBR Oberlin Owner, LLC	WR-1792, SUB 0	(04/13/2015)
(401 Oberlin Apartments)		
The Aventine Asheville, LLC	WR-1834, SUB 0	(06/01/2015)
(Aventine Asheville Apartments)		
The Collection at the Park, LLC	WR-1960, SUB 0	(12/14/2015)
(Silver Collection at the Park Apartments)		
The Lofts, LLC	WR-1843, SUB 0	(06/23/2015)
(Vistas at 707 Apartments)		
The New Oaks, LLC	WR-1818, SUB 0	(05/04/2015)
(The Oaks Apartments)		
The Sanctuary at Charlotte, LLC	WR-1758, SUB 0	(02/17/2015)
(Arcadia Student Living Apartments)		
Tilden Legacy Beech Lake Apartments, LLC	WR-1947, SUB 0	(11/25/2015)
(Beech Lake Apartments)		
TP 1100 South Blvd., LLC	WR-1817, SUB 0	(05/05/2015)
(1100 South Apartments)		
Trade & Graham Associates, LLC	WR-1966, SUB 0	(12/28/2015)
(The Mint Apartments)		
Triangle Palisades of Asheville, Inc.	WR-1787, SUB 0	(04/07/2015)
(Palisades Apartments)		
Triangle Real Estate of Gastonia, Inc.		
(Woodbridge Apartments)	WR-1125, SUB 15	(04/07/2015)
(Avalon at Sweeten Creek Apt. Homes)	WR-1125, SUB 16	(08/20/2015)
Triforte, LLC	WR-1910, SUB 0	(10/08/2015)
(Shamrock Garden Apartments)		
Trinity Properties, LLC	WR-1696, SUB 9	(12/30/2015)
(Campus Walk Apartments)		
Umstead Raleigh Investors, LLC	WR-1772, SUB 0	(03/23/2015)
(Four Seasons at Umstead Park Apts.)		
VantagePointe Investments of Waynesville, LLC	WR-1893, SUB 0	(09/28/2015)
(Vantage Pointe Homes of Balsam Mtn. Apts.)		
VCP Ambercrest, LLC	WR-1812, SUB 0	(04/29/2015)
(Ambercrest Apartments)		
VCP Birchcroft, LLC	WR-1888, SUB 0	(09/14/2015)
(Birchcroft Apartments)		
VCP Hunt Club, LLC	WR-1820, SUB 0	(05/11/2015)
(Hunt Club Apartments)		
VCP Lakes Meadowood, LLC	WR-1810, SUB 0	(04/29/2015)
(The Lakes on Meadowood Apartments)		

WATER RESELLERS – Certificate *(Continued)*

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
VCP The Ashland, LLC *(The Ashland Apartments)*	WR-1811, SUB 0	(04/29/2015)
Villas at Granite Ridge, LLC *(The Villas at Granite Ridge Apartments)*	WR-1788, SUB 0	(04/07/2015)
Walden Court, Inc. *(Walden Court Apartments)*	WR-1878, SUB 0	(08/20/2015)
Water Oak NC Partners, LLC *(The Regency Apartments)*	WR-1850, SUB 0	(07/02/2015)
Waterford Lakes NC Partners, LLC *(Waterford Lakes Apartments)*	WR-1854, SUB 0	(07/02/2015)
Weston Parkway Partners, LLC *(Weston Corners Apartments)*	WR-1837, SUB 0	(06/15/2015)
Willow Run, LLC *(Willow Run Apartments)*	WR-1827, SUB 0	(05/27/2015)
Winter Oaks NC Partners, LLC *(Aspen Peak Apartments)*	WR-1853, SUB 0	(07/02/2015)
Woodland Estates Mobile Home Park *(Woodland Estates Mobile Home Park)*	WR-1863, SUB 0	(07/21/2015)
WOP Cornerstone, LLC *(Cornerstone Apartments)*	WR-1905, SUB 0	(09/29/2015)
3Mind Remington Place, LLC, et al. *(The Timbers Apartments)*	WR-1858, SUB 0	(07/14/2015)
3Mind Timbers, LLC, et al. *(The Timbers Apartments)*	WR-1857, SUB 0	(07/14/2015)
102 North Elm Street Tenant, LLC *(102 North Elm Street Apartments)*	WR-1921, SUB 0	(10/21/2015)
4700 Twisted, LLC *(Wellington Farms Apartments)*	WR-1885, SUB 0	(08/25/2015)
6200 Raleigh Apartments, LLC *(Marchester on Millbrook Apartments)*	WR-1882, SUB 0	(08/24/2015)

Hawthorne-Charleston Strickland, LLC, et al. -- WR-1778, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates *(Hawthorne Glen at Strickland Apartments)* (11/06/2015)

LHNH – Northwoods Townhomes NC, LLC -- WR-1918, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates *(Northwoods Townhomes Apartments, Phase I)* (11/03/2015)

Melrose Condos, Inc. -- WR-1871, SUB 0; Errata Order *(Melrose Apartments)* (08/18/2015)

3Mind Remington Place, LLC, et al. -- WR-1858, SUB 0; Errata Order *(Remington Place Apartments)* (07/27/2015)

WATER RESELLERS – Certificate *(Continued)*

ORDER GRANTING HWCCWA CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
Central Pointe Apartments, LLC *(Central Pointe Apartments)*	WR-1479, SUB 2	(02/10/2015)
FC Hidden Creek, LLC *(North Oaks Landing Apartments)*	WR-1724, SUB 1	(03/09/2015)
Gorman Crossing, LLC *(Gorman Crossing Apartments)*	WR-1698, SUB 0	(01/07/2015)
GrayBul Sherwood Ridges, LP *(Sherwood Ridges Apartments)*	WR-1861, SUB 0	(07/15/2015)
Hudson Redwood Lexington, LLC *(Lexington Farms Apartments)*	WR-1823, SUB 0	(05/12/2015)
Kensington Apartments *(Kensington Park Apartments)*	WR-1692, SUB 0	(01/07/2015)
Madison Greensboro, LLC *(Madison Woods Apartments)*	WR-1783, SUB 0	(04/06/2015)
Penrith Townhomes, LLC *(Woodland Creek Apartments)*	WR-1763, SUB 1	(05/26/2015)
SBV-Greensboro-II, LLC *(LeMans at Lawndale Apartments)*	WR-1690, SUB 1	(05/05/2015)
Sharon Pines, LLC *(Sharon Pines Apartments)*	WR-1798, SUB 0	(05/11/2015)
The Glen G, LLC *(The Glen Apartments, Phases 4-5)*	WR-1923, SUB 0	(10/26/2015)
The Glen K, LLC *(The Glen Apartments, Phases 1-3)*	WR-1930, SUB 0	(10/26/2015)
Triforte, LLC *(Shamrock Garden Apartments)*	WR-1910, SUB 1	(12/22/2015)

Hudson Redwood Lexington, LLC -- WR-1823, SUB 0; Reissued Order Granting HWCCWA Certificate of Authority and Approving Rates *(Lexington Farms Apts.)* (05/13/2015)
MP Vista Villa, LLC -- WR-1711, SUB 0; Errata Order *(Vista Villa Apartments)* (01/06/2015)

ORDERS AND DECISIONS LISTED

WATER RESELLERS – Sale/Transfer

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
AGM Wilmington, LLC	WR-1890, SUB 0	(09/02/2015)
(St. Andrews Reserve Apartments)	WR-111, SUB 11	
Alexander Village Acquisition, LP	WR-1955, SUB 0	(12/22/2015)
(Crescent Alexander Village Apts.)	WR-1652, SUB 1	
Arium Pinnacle Ridge, LLC	WR-1770, SUB 0	(03/10/2015)
(Pinnacle Ridge Apartments)	WR-518, SUB 10	
Ashbury Square, LLC	WR-1773, SUB 0	(03/24/2015)
(Ashbury Square Apartments)	WR-485, SUB 6	
Avery Millbrook, LLC	WR-1020, SUB 14	(09/24/2015)
(Millbrook Apartments 2)	WR-875, SUB 23	
AVR Charlotte Perimeter Lofts, LLC	WR-1739, SUB 0	(01/12/2015)
(Perimeter Lofts Apartments)	WR-1468, SUB 2	
AVR Charlotte Perimeter Station, LLC	WR-1738, SUB 0	(01/12/2015)
(Perimeter Station Apartments)	WR-914, SUB 4	
Beaver Creek Apex, LLC	WR-881, SUB 3	(01/12/2015)
(Beaver Creek Townhomes Apts., Sec. II)	WR-878, SUB 3	
Bell Fund V Hawfield Farms, LP	WR-1904, SUB 0	(09/30/2015)
(Bell Ballantyne Apartments)	WR-891, SUB 5	
Bell HNW Exchange Apex, LLC	WR-1765, SUB 0	(03/10/2015)
(Bell Apex Apartments)	WR-1241, SUB 2	
Belle Haven Acquisition, LLC	WR-1822, SUB 0	(05/12/2015)
(Belle Haven Apartments)	WR-1518, SUB 3	
BES Manor Six Forks Fund XI, LLC, et al.	WR-1731, SUB 0	(01/05/2015)
(Manor Six Forks Luxury Apts.)	WR-1685, SUB 1	
BES Southern Oaks Fund XI, LLC, et al.	WR-1750, SUB 0	(02/02/2015)
(Southern Oaks at Davis Park Apts.)	WR-1176, SUB 2	
BMPP Cameron Limited Partnership	WR-1776, SUB 0	(03/24/2015)
(Crescent Cameron Village Apts.)	WR-1675, SUB 1	
BR Park & Kingston Charlotte, LLC	WR-1795, SUB 0	(04/21/2015)
(Park and Kingston Apartments)	WR-1538, SUB 2	
BR-TBR Whetstone Owner, LLC	WR-1881, SUB 0	(08/21/2015)
(Whetstone Apartments)	WR-1688, SUB 1	
Breckenridge Group CNC, LLC	WR-1815, SUB 0	(05/04/2015)
(Aspen Charlotte Apartments)	WR-1684, SUB 1	
BRK Kensington Place, LP	WR-1733, SUB 0	(01/13/2015)
(Kensington Place Apartments)	WR-1245, SUB 2	
BRK Matthews, LP	WR-1732, SUB 0	(01/13/2015)
(Matthews Pointe Apartments)	WR-912, SUB 4	

WATER RESELLERS – Sale/Transfer *(Continued)*

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued (Continued)

Company	Docket No.	Date
BRK Osprey Landing, LP	WR-1735, SUB 0	(01/13/2015)
(Osprey Landing Apartments)	WR-1255, SUB 1	
BRK Pecan Grove, LP	WR-1734, SUB 0	(01/13/2015)
(Hanover Landing Apartments)	WR-1246, SUB 1	
BRK Waterford Hills, LP	WR-1737, SUB 0	(01/13/2015)
(Waterford Hills Apartments)	WR-1061, SUB 4	
BRK Wimbledon Chase, LP	WR-1736, SUB 0	(01/13/2015)
(Wimbledon Chase Apartments)	WR-1244, SUB 1	
BWP North Pointe Holdco, LLC	WR-1950, SUB 0	(12/01/2015)
(North Pointe Commons Apartments)	WR-895, SUB 2	
Carroll at Cityview, LLC	WR-1838, SUB 0	(08/25/2015)
(Carroll at Cityview Apts.)	WR-702, SUB 7	
	WR-1236, SUB 5	
Cary Pines at Preston, LLC	WR-1862, SUB 0	(07/15/2015)
(Preston Apartments)	WR-1207, SUB 4	
CCC Uptown Gardens, LLC	WR-1794, SUB 0	(04/14/2015)
(Uptown Gardens Apartments)	WR-1346, SUB 2	
CCC Villages at Pecan Grove, LLC	WR-1970, SUB 0	(12/29/2015)
(The Villages at Pecan Grove Apts.)	WR-1508, SUB 1	
Centennial Highland Creek, LLC	WR-1952, SUB 0	(12/01/2015)
(Century Highland Creek Apts.)	WR-1392, SUB 3	
Centennial Tryon Place, LLC	WR-1897, SUB 0	(09/16/2015)
(Century Tryon Place Apartments)	WR-1563, SUB 1	
CM Apartments, LLC	WR-1785, SUB 0	(04/06/2015)
(Longview Meadow Apartments)	WR-825, SUB 5	
Colony Village Apartments, LLC	WR-1902, SUB 0	(09/25/2015)
(Colony Village Apartments)	WR-1715, SUB 4	
Coral Stone, LLC	WR-1876, SUB 0	(08/19/2015)
(Forest Pointe 2, Apartments)	WR-1645, SUB 1	
Cumberland Cove, LLC	WR-1771, SUB 0	(03/10/2015)
(Cumberland Cove Apartments)	WR-200, SUB 11	
DPR Cary, LLC	WR-1743, SUB 0	(01/20/2015)
(The Reserve at Cary Park Apts.)	WR-553, SUB 6	
Elite Street Capital Lincoln Green DE, LLC	WR-1936, SUB 0	(11/18/2015)
(Lincoln Green Apartments)	WR-527, SUB 8	
Forestdale W99 LAP, LLC	WR-1847, SUB 0	(06/30/2015)
(Hawthorne at Forestdale Apts.)	WR-1181, SUB 6	

ORDERS AND DECISIONS LISTED

WATER RESELLERS – Sale/Transfer *(Continued)*

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued (Continued)

Company	Docket No.	Date
Fountains Mooresville, LLC	WR-1753, SUB 0	(02/10/2015)
(Fountains at Mooresville Town Sq. Apts.)	WR-1274, SUB 1	
Ginkgo Abbington, LLC	WR-1962, SUB 0	(12/15/2015)
(Abbington Place Apartments)	WR-454, SUB 10	
Ginkgo Kimmerly, LLC	WR-1729, SUB 0	(01/05/2015)
(Kimmerly Glen Apartments)	WR-1054, SUB 5	
Ginkgo OBC, LLC	WR-1558, SUB 2	(03/10/2015)
(Hawthorne at Commonwealth Apts.)	WR-1381, SUB 2	
Ginkgo Savannah, LLC	WR-1937, SUB 0	(11/18/2015)
(Savannah Place Apartments)	WR-474, SUB 8	
Golden Triangle #5–Providence Sq., LLC, et al.	WR-1759, SUB 0	(02/17/2015)
(Crest on Providence Apartments)	WR-913, SUB 4	
Gray Property 2004, LLC	WR-1967, SUB 0	(12/28/2015)
(The Exchange at Brier Creek Apts.)	WR-1209, SUB 4	
Hawthorne-Midway Venue, LLC, et al.	WR-1845, SUB 0	(06/23/2015)
(Hawthorne at Lake Norman Apartments)	WR-1530, SUB 1	
Hudson Capital Park Forest, LLC	WR-1869, SUB 0	(08/07/2015)
(Park Forest Apartments)	WR-493, SUB 7	
Hudson Capital Steeplechase, LLC	WR-1868, SUB 0	(08/07/2015)
(Steeplechase Apartments)	WR-497, SUB 7	
Juliet Place Holdings, LLC	WR-1859, SUB 0	(07/15/2015)
(Juliet Place Apartments)	WR-908, SUB 2	
LSREF3 Bravo (Raleigh), LLC	WR-1717, SUB 5	(03/02/2015)
(Oaks at Weston Apartments)	WR-778, SUB 9	
LWH Ashley Oaks Apartments, LP	WR-1953, SUB 0	(12/01/2015)
(Ashley Oaks Apartments)	WR-1407, SUB 4	
MA Ethan Pointe at Burlington, LLC	WR-1894, SUB 0	(09/11/2015)
(Ethan Pointe Apartments)	WR-744, SUB 5	
MAR Flagstone, LLC	WR-1924, SUB 0	(10/28/2015)
(Flagstone at Indian Trail Apartments)	WR-1386, SUB 4	
Miami MADE, LLC	WR-1938, SUB 0	(11/18/2015)
(Lakeview Mobile Home Park)	WR-849, SUB 5	
Midtown Green Realty Company, LLC	WR-1782, SUB 0	(04/06/2015)
(Midtown Green Apartments)	WR-1612, SUB 2	
NC2, LLC	WR-1730, SUB 0	(01/05/2015)
(Beechwood Apartments)	WR-1588, SUB 2	
New Haw Creek Associates, LLC	WR-624, SUB 3	(01/12/2015)
(Haw Creek Mews II Apartments)	WR-625, SUB 3	

WATER RESELLERS – Sale/Transfer *(Continued)*

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
NR Pinehurst Property Owner, LLC	WR-1745, SUB 0	(01/26/2015)
(Camden Pinehurst Apartments)	WR-42, SUB 71	
ORP EMM, LLC	WR-1769, SUB 0	(03/10/2015)
(The Flats at 55 Twelve Apartments)	WR-306, SUB 7	
Pen & Lin Wood, LLC	WR-1802, SUB 0	(04/20/2015)
(Penwood Apartments)	WR-1448, SUB 3	
Rehobeth Pointe Holdings, LLC	WR-1860, SUB 0	(07/15/2015)
(Rehobeth Pointe Apartments)	WR-730, SUB 3	
RW Hawk Ridge, LLC	WR-1747, SUB 0	(01/26/2015)
(Hawk Ridge Apartments)	WR-1182, SUB 4	
Southpark Morrison, LLC	WR-1934, SUB 0	(11/30/2015)
(Southpark Morrison Apartments)	WR-1250, SUB 5	
SPUS7 Tribute, LP	WR-1846, SUB 0	(06/29/2015)
(The Tribute Apartments)	WR-1195, SUB 4	
Sterling Arbor Creek, LLC	WR-1906, SUB 0	(09/30/2015)
(Arbor Creek Apartments)	WR-1102, SUB 4	
Sterling Reserve at Magnolia Ridge LLC	WR-1949, SUB 0	(11/25/2015)
(Reserve at Magnolia Ridge Apts.)	WR-1604, SUB 2	
Terrace Oaks, LLC	WR-1945, SUB 0	(11/24/2015)
(Terrace Oaks Apartments)	WR-792, SUB 2	
Waypoint Chapel Hill Owner, LLC	WR-1791, SUB 0	(04/13/2015)
(Preserve at the Park Apartments)	WR-1496, SUB 1	
WGL Associates, LLC	WR-1940, SUB 0	(11/18/2015)
(Pepperstone Apartments)	WR-445, SUB 12	
Wilkinson High Point II, LLC	WR-1762, SUB 0	(03/03/2015)
(Eastchester Ridge Apartments)	WR-509, SUB 9	
WMCi Raleigh IX, LLC	WR-1754, SUB 0	(02/10/2015)
(The Belmont Apartments)	WR-752, SUB 8	
4200 Investments Phase One, LLC	WR-1973, SUB 0	(12/30/2015)
(Villagio Apartments)	WR-1177, SUB 3	

Breckenridge Group CNC, LLC -- WR-1815, SUB 0; Errata Order *(Aspen Charlotte Apartments)* (06/02/2015)

Hawthorne-Midway Venue, LLC, et al. -- WR-1845, SUB 0; WR-1530, SUB 1; Errata Order *(Hawthorne at Lake Norman Apartments)* (06/25/2015)

WATER RESELLERS – Sale/Transfer *(Continued)*

ORDER GRANTING HWCCWA TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
Brynn Marr Apartments, LLC		
(Brynn Marr Apartments)	WR-1901, SUB 0 WR-1715, SUB 3	(09/25/2015)
Colony Burlington, LLC		
(Colony Apartments)	WR-1931, SUB 0 WR-1395, SUB 4	(11/03/2015)
Fairfield Raefield Village, LLC		
(Raefield Village Apartments)	WR-1774, SUB 0 WR-793, SUB 3	(03/24/2015)
Ginkgo Glendare, LLC		
(Glendare Park Apartments)	WR-1968, SUB 0 WR-1230, SUB 2	(12/29/2015)
Princeton Villas, LLC		
(Chesterfield Apartments)	WR-1971, SUB 0 WR-831, SUB 125	(12/30/2015)
(Eastwood Apartments)	WR-1971, SUB 1 WR-831, SUB 126	(12/30/2015)
(Briarwood Apartments)	WR-1971, SUB 2 WR-831, SUB 127	(12/30/2015)
(Oakwood Apartments)	WR-1971, SUB 3 WR-831, SUB 128	(12/30/2015)
(Rosewood Apartments)	WR-1971, SUB 4 WR-831, SUB 129	(12/30/2015)
(Princeton Apartments)	WR-1971, SUB 5 WR-831, SUB 130	(12/30/2015)
Villages of Chapel Hill, LLC		
(Villages at Chapel Hill Apartments)	WR-1841, SUB 0 WR-1203, SUB 2	(06/23/2015)

BRK Osprey Landing, LP -- WR-1735, SUB 0; WR-1255, SUB 1; Reissued Order Granting HWCCWA Transfer of Certificate of Authority and Approving Rates *(Osprey Landing Apartments)* (02/11/2015)

ORDERS AND DECISIONS LISTED

WATER RESELLERS – Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION
Orders Issued

Company	Docket No.	Date
Abberly Place Place – Garner – Phase I Limited Partnership		
(Abberly Place Apartments)	WR-305, SUB 8	(03/24/2015)
(Abberly Place Apartments)	WR-305, SUB 9	(10/23/2015)
Abbington SPE, LLC *(Abbington Place Apartments)*	WR-596, SUB 4	(02/16/2015)
Addington Ridge, LLC *(Addington Ridge Apartments)*	WR-1656, SUB 1	(12/28/2015)
Addison Point, LLC *(Addison Point Apartments)*	WR-748, SUB 7	(09/09/2015)
AERC Alpha Mill Lane, LP		
(Alpha Mill Apartments)	WR-1649, SUB 4	(04/27/2015)
(Alpha Mill Apartments)	WR-1649, SUB 5	(10/07/2015)
AERC Arboretum, LP *(The Arboretum Apartments)*	WR-1277, SUB 2	(10/07/2015)
AERC Blakeney, LP *(The Apartments at Blakeney)*	WR-1547, SUB 2	(10/07/2015)
AERC Crossroads, LP *(The Park at Crossroads Apartments)*	WR-1328, SUB 2	(10/07/2015)
AERC Lofts Lakeside, LP *(Lofts at Weston Apartments)*	WR-1586, SUB 3	(10/07/2015)
AERC Southpoint, LP *(Southpoint Village Apartments)*	WR-1312, SUB 2	(10/07/2015)
Alaris Village Apartments *(Alaris Village Apartments)*	WR-894, SUB 6	(04/27/2015)
Allen H. Moss		
(Crestview II Mobile Home Park)	WR-896, SUB 12	(08/31/2015)
(Maple Terrace Mobile Home Park)	WR-896, SUB 13	(08/31/2015)
Allen's MHP, LLC *(Dogwood Hills Mobile Home Park)*	WR-1575, SUB 1	(11/17/2015)
Amelia Village Phase I, LLC *(Amelia Village Apartments)*	WR-1220, SUB 2	(12/28/2015)
AMFP II Waterford Village, LLC *(Arboretum at Southpoint Apts.)*	WR-1340, SUB 1	(07/29/2015)
Ansley Falls Apartments, LLC *(Ansley Falls Apartments)*	WR-1603, SUB 2	(08/10/2015)
Ansley Roberts Lake Apartments, LLC *(Ansley at Roberts Lake Apts.)*	WR-1804, SUB 1	(08/10/2015)

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Apartment REIT Residences at Braemar, LLC	WR-655, SUB 4	(10/06/2015)
(The Residences at Braemar Apts.)		
AR I Borrower, LLC	WR-1585, SUB 2	(11/16/2015)
(Ashton Reserve at Northlake Apts.)		
Arbor Steele Creek, LLC	WR-1499, SUB 1	(02/02/2015)
(Arbor Steele Creek Apartments)		
Ardrey Kell Townhomes, LLC		
(Hawfield Farms Apartments)	WR-891, SUB 3	(03/02/2015)
(Hawfield Farms Apartments)	WR-891, SUB 4	(09/01/2015)
ARIM Crossroads, LLC	WR-1748, SUB 1	(10/19/2015)
(Crossroads North Hills Apartments)		
Arium Research Triangle Park Owner, LLC		
(Arium Research Triangle Park Apts.)	WR-1528, SUB 1	(02/09/2015)
(Arium Research Triangle Park Apts.)	WR-1528, SUB 2	(08/18/2015)
Arthur E. & Florence H. Heinmiller	WR-1094, SUB 3	(10/06/2015)
(Apple Blossom Mobile Home Park)		
Ascot Point Village Apartments, LLC	WR-273, SUB 12	(10/20/2015)
(Ascot Point Village Apartments)		
Ashborough Investors, LLC	WR-489, SUB 8	(09/25/2015)
(Ashborough Apartments)		
Asheville Apartments Investors, LLC	WR-1327, SUB 3	(08/06/2015)
(Reserve at Asheville Apartments)		
Ashford Place Apartments, LLC		
(Ashford Place Apartments)	WR-1707, SUB 1	(02/16/2015)
(Ashford Place Apartments)	WR-1707, SUB 2	(08/17/2015)
Ashley Park Associates, LLC	WR-960, SUB 3	(08/10/2015)
(Ashley Park at Brier Creek Apts.)		
Ashley Park, LLC	WR-1576, SUB 1	(10/12/2015)
(Solis Sharon Square Apartments)		
Ashton Village Limited Partnership		
(Abberly Place Apartments, Ph. II)	WR-802, SUB 7	(03/24/2015)
(Abberly Place Apartments)	WR-802, SUB 8	(10/23/2015)
Atkins Circle I, LLC	WR-277, SUB 5	(10/13/2015)
(Atkins Circle I Apartments)		
Atkins Circle II, LLC	WR-747, SUB 3	(10/13/2015)
(Atkins Circle Phase II Apartments)		
Atwood, LLC	WR-1283, SUB 2	(08/10/2015)
(Knollwood Apartments)		

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Autumn Park Owner, LLC	WR-1378, SUB 3	(08/06/2015)
(Autumn Park Charlotte Apts.)		
Autumn Ridge RS, LLC	WR-1016, SUB 1	(09/10/2015)
(Autumn Ridge Apartments)		
Avery Millbrook, LLC		
(Avery Square Apartments)	WR-1020, SUB 12	(09/08/2015)
(Millbrook Apartments)	WR-1020, SUB 13	(09/08/2015)
AVR Charlotte Perimeter Lofts, LLC	WR-1739, SUB 1	(11/30/2015)
(Perimeter Lofts Apartments)		
AVR Charlotte Perimeter Station, LLC	WR-1738, SUB 1	(11/30/2015)
(Perimeter Station Apartments)		
Barrington Apartments, LLC	WR-384, SUB 13	(07/28/2015)
(Legacy North Pointe Apts.)		
Barrington Village Apartments, LLC	WR-380, SUB 9	(04/27/2015)
(Brannigan Village Apartments)		
Battleground North Apartments, LLC	WR-672, SUB 6	(10/20/2015)
(Battleground North Apartments)		
BBR/Barrington, LLC	WR-619, SUB 8	(09/24/2015)
(Barrington Place Apartments)		
BBR/Brookford, LLC	WR-614, SUB 8	(11/30/2015)
(Brookford Place Apartments)		
BBR/Madison Hall, LLC	WR-603, SUB 4	(11/10/2015)
(Madison Hall Apartments)		
Beachwood Associates, LLC	WR-880, SUB 4	(10/19/2015)
(Beachwood Park Apartments)		
Beachwood II Associates, LLC	WR-1824, SUB 1	(10/14/2015)
(Loch Raven Pointe Apartments)		
Bel Pineville Holdings, LLC	WR-1037, SUB 5	(08/20/2015)
(Berkshire Place Apartments)		
Bel Ridge Holdings, LLC	WR-1053, SUB 5	(09/02/2015)
(McAlpine Ridge Apartments)		
Bell Fund IV Morrison Apartments, LLC	WR-1250, SUB 4	(05/18/2015)
(Bell Morrison Apartments)		
Bell Fund IV Morrisville Apartments, LLC	WR-1391, SUB 3	(08/17/2015)
(Bell Preston View Apartments)		
Bell Fund V Wakefield, LLC	WR-1540, SUB 2	(08/19/2015)
(Bell Wakefield Apartments)		
Belle Haven Acquisition, LLC	WR-1822, SUB 1	(09/02/2015)
(Belle Haven Apartments)		

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Belle Haven, LLC	WR-1518, SUB 1	(01/05/2015)
(Belle Haven Apartments)		
Belmont at Southpoint, LLC		
(Berkeley at Southpoint Apartments)	WR-187, SUB 9	(02/09/2015)
(Berkeley at Southpoint Apartments)	WR-187, SUB 10	(02/24/2015)
(Berkeley at Southpoint Apartments)	WR-187, SUB 11	(08/18/2015)
Berrington Village Apartments, LLC	WR-1153, SUB 4	(10/20/2015)
(Berrington Village Apartments)		
BES Manor Six Forks Fund XI, LLC, et al.	WR-1731, SUB 1	(12/14/2015)
(Manor Six Forks Apartments)		
BES Steele Creek Fund IX, LLC, et al.	WR-1352, SUB 3	(12/14/2015)
(Preserve at Steele Creek Apartments)		
Best Mulch, Inc.	WR-513, SUB 7	(09/16/2015)
(Clairmont Crest Mobile Home Park)		
BHC – Hawthorne Pinnacle Ridge, LLC		
(Hawthorne Northside Apartments)	WR-1513, SUB 1	(04/29/2015)
(Hawthorne Northside Apartments)	WR-1513, SUB 2	(09/21/2015)
BHI-SEI Mariners, LLC	WR-1228, SUB 2	(11/17/2015)
(Mariners Crossing Apartments)		
BMA Davidson Apartments, LLC	WR-707, SUB 5	(07/31/2015)
(Davidson Apartments)		
BMA Eden Apartments, LLC	WR-728, SUB 6	(02/09/2015)
(Arbor Glen Apartments)		
BMA Heatherwood Kensington Apts., LLC	WR-708, SUB 5	(07/31/2015)
(Heatherwood/Kensington Apts.)		
BMA Huntersville Apartments, LLC	WR-811, SUB 7	(07/30/2015)
(Huntersville Apartments)		
BMA Lakewood, LLC	WR-817, SUB 5	(01/26/2015)
(Lakewood Apartments)		
BMA Monroe III Apartments, LLC	WR-812, SUB 8	(07/30/2015)
(Woodbrook Apartments)		
BMA North Sharon Amity, LLC	WR-810, SUB 7	(07/30/2015)
(Sharon Pointe Apartments)		
BMA Oxford Apartments, LLC	WR-710, SUB 3	(07/30/2015)
(Autumn Park Apartments)		
BMA Shelby Apartments, LLC		
(Marion Ridge Apartments)	WR-709, SUB 4	(02/09/2015)
(Marion Ridge Apartments)	WR-709, SUB 5	(08/24/2015)
BMA Water's Edge Apartments, LLC	WR-711, SUB 5	(07/31/2015)
(Water's Edge Apartments)		

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
BMA Wexford, LLC	WR-813, SUB 7	(07/30/2015)
(Wexford Apartments)		
BMPP Cameron Limited Partnership	WR-1776, SUB 1	(10/26/2015)
(Berkshire Cameron Village Apts.)		
BNP/Abbington, LLC	WR-454, SUB 9	(10/05/2015)
BNP/Pepperstone, LLC	WR-445, SUB 10	(10/05/2015)
(Pepperstone Apartments)		
BR Park & Kingston Charlotte, LLC		
(Park and Kingston Apartments)	WR-1795, SUB 1	(09/29/2015)
(Park and Kingston Apartments)	WR-1795, SUB 2	(12/28/2015)
BRC Abernathy, LLC, et al.	WR-1057, SUB 5	(08/17/2015)
(Abernathy Park Apartments)		
BRC Charlotte 485, LLC	WR-501, SUB 8	(08/17/2015)
(Halton Park Apartments)		
BRC Jacksonville Commons, LLC	WR-1275, SUB 2	(02/16/2015)
(Reserve at Jacksonville Commons Apts.)		
BRC Knightdale, LLC		
(Berkshire Park Apartments)	WR-938, SUB 6	(02/17/2015)
(Berkshire Park Apartments)	WR-938, SUB 7	(07/28/2015)
BRC Majestic Apartments, LLC		
(Palladium Park Apartments)	WR-374, SUB 6	(02/16/2015)
(Palladium Park Apartments)	WR-374, SUB 7	(11/03/2015)
BRC Salisbury, LLC		
(Salisbury Village Apartments)	WR-500, SUB 5	(02/23/2015)
(Salisbury Village Apartments)	WR-500, SUB 6	(07/28/2015)
BRC Whites Mill, LLC		
(Alexandria Park Apartments)	WR-830, SUB 5	(02/17/2015)
(Alexandria Park Apartments)	WR-830, SUB 6	(11/03/2015)
BRC Wilson, LLC	WR-502, SUB 5	(07/28/2015)
(Thornberry Park Apartments)		
BRE Cary Park Apartments, LLC	WR-1637, SUB 1	(07/21/2015)
(Marquis on Cary Parkway Apts.)		
BRE Edwards Mill Apartments, LLC	WR-1639, SUB 1	(11/16/2015)
(The Marquis on Edwards Mill Apts.)		
Breckenridge Group CNC, LLC	WR-1815, SUB 1	(09/16/2015)
(Aspen Charlotte Apartments)		
Bridford Parkway Apartments, LLC		
(Hawthorne at Bridford Apts.)	WR-1363, SUB 1	(03/23/2015)
(Hawthorne at Bridford Apts.)	WR-1363, SUB 2	(09/16/2015)

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WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
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Company	Docket No.	Date
BRK Kensington Place	WR-1733, SUB 1	(08/18/2015)
(Kensington Place Apartments)		
BRK Matthews, LP	WR-1732, SUB 1	(08/20/2015)
(Matthews Pointe Apartments)		
BRK Waterford Hills, LP	WR-1737, SUB 1	(08/20/2015)
(Waterford Hills Apartments)		
BRNA, LLC	WR-75, SUB 15	(08/10/2015)
(Bryn Athyn Apartments)		
Brookberry Park Apartments, LLC	WR-798, SUB 8	(11/03/2015)
(Brookberry Park Apartments)		
Brookstown Winston-Salem Apartments, LLC	WR-1618, SUB 1	(01/12/2015)
(Link Apartments Brookstown)		
Bruce A. Kubeck		
(Interstate Mobile Home Park)	WR-310, SUB 32	(10/19/2015)
(Cedar Grove Mobile Home Park)	WR-310, SUB 33	(10/19/2015)
(Dogwood Circle Mobile Home Park)	WR-310, SUB 34	(10/19/2015)
Bryant Park Apartments, LLC	WR-1687, SUB 1	(08/04/2015)
(Morehead West Apartments)		
Burd Properties Fayetteville, LLC		
(Meadowbrook at King's Grant Apts.)	WR-585, SUB 19	(05/26/2015)
(Stoney Ridge Apartments)	WR-585, SUB 20	(05/26/2015)
(Carlson Bay Apartments)	WR-585, SUB 21	(05/26/2015)
Caitlin Station Limited Partnership		
(Caitlin Station Apartments)	WR-180, SUB 5	(02/16/2015)
(Caitlin Station Apartments)	WR-180, SUB 6	(08/24/2015)
Camden Summit Partnership, LP		
(Camden Overlook Apartments)	WR-6, SUB 167	(09/10/2015)
(Camden Crest Apartments)	WR-6, SUB 168	(09/10/2015)
(Camden Foxcroft Apartments)	WR-6, SUB 169	(09/10/2015)
(Camden South End Square Apts.)	WR-6, SUB 170	(09/10/2015)
(Camden Stonecrest Apartments)	WR-6, SUB 171	(09/10/2015)
(Camden Touchstone Apts.)	WR-6, SUB 172	(09/10/2015)
(Camden Simsbury Apartments)	WR-6, SUB 173	(09/10/2015)
(Camden Fairview Apartments)	WR-6, SUB 174	(09/10/2015)
(Camden Cotton Mills Apartments)	WR-6, SUB 175	(09/10/2015)
Camden USA, LLC	WR-1836, SUB 1	(09/11/2015)
(Camden Gallery Apartments)		
Cape Fear Multifamily, LLC	WR-1264, SUB 3	(07/13/2015)
(The Astoria at Hope Mills Apts.)		

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Carlyle Centennial Parkside, LLC	WR-942, SUB 6	(08/04/2015)
(Century Parkside Apartments)		
Carmel Valley II, LP	WR-71, SUB 9	(09/23/2015)
(Marquis at Carmel Commons Apts.)		
Carolina Village MHC, LLC	WR-1215, SUB 2	(07/06/2015)
(Carolina Village Mobile Home Park)		
Carrington Place CAF II, LLC	WR-1686, SUB 1	(08/24/2015)
(Carrington Park Apartments)		
Cary Towne Park, LLC	WR-874, SUB 4	(02/23/2015)
(Legends Cary Towne Apartments)		
CCC Brassfield Park, LLC	WR-1619, SUB 2	(08/18/2015)
(Brassfield Park Apartments)		
CCC Forest at Biltmore Park, LLC, et al.	WR-1742, SUB 1	(08/21/2015)
(Forest at Biltmore Park Apartments)		
CCC Gallery Lofts, LLC	WR-1708, SUB 1	(11/02/2015)
(Gallery Lofts Apartments)		
CCC Old Raleigh, LLC	WR-1814, SUB 1	(09/28/2015)
(Olde Raleigh Apartments)		
CCC One Norman Square, LLC	WR-1628, SUB 1	(08/21/2015)
(One Norman Square Apartments)		
CCC Sommerset Place, LLC	WR-1446, SUB 3	(09/02/2015)
(Sommerset Place Apartments)		
CCC Summerlin Ridge, LLC	WR-1805, SUB 1	(11/16/2015)
(Summerlin Ridge Apts.)		
CCC Uptown Gardens, LLC	WR-1794, SUB 1	(09/23/2015)
(Uptown Gardens Apartments)		
CCC Windsor Falls, LLC		
(Windsor Falls Apartments)	WR-1373, SUB 2	(02/09/2015)
(Windsor Falls Apartments)	WR-1373, SUB 3	(10/19/2015)
Cedar Grove MHC, LLC	WR-1398, SUB 1	(07/06/2015)
(Cedar Grove Mobile Home Park)		
Cedar Trace, LLC	WR-897, SUB 7	(09/09/2015)
(Cedar Trace Apartments)		
CEG Friendly Manor, LLC		
(Legacy at Friendly Manor Apts.)	WR-266, SUB 8	(02/23/2015)
(Legacy at Friendly Manor Apts.)	WR-266, SUB 9	(08/17/2015)
Centennial Addington Farms, LLC	WR-1403, SUB 3	(08/12/2015)
(Century Trinity Estates Apartments)		
Centennial Northlake, LLC	WR-1661, SUB 2	(08/12/2015)
(Century Northlake Apartments)		

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<u>WATER RESELLERS – Tariff Revision for Pass-Through</u> *(Continued)*

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Company	Docket No.	Date
CF FWB Elements, LLC	WR-1719, SUB 1	(08/19/2015)
(Elements on Park Apartments)		
CF FWB Lakeside, LLC	WR-1720, SUB 1	(08/19/2015)
(Lakeside Apartments)		
CF FWB Runaway Bay, LLC	WR-1728, SUB 1	(08/19/2015)
(Runaway Bay Apartments)		
CH Realty V/Park and Market, LLC	WR-1303, SUB 3	(08/21/2015)
(Park and Market Apartments)		
Chamberlain Place Apartments, LLC	WR-819, SUB 5	(11/09/2015)
(Chamberlain Place Apartments)		
CLNL Acquisition Sub, LLC		
(Colonial Village at Deerfield Apts.)	WR-975, SUB 39	(09/22/2015)
(Colonial Grand at Legacy Park Apts.)	WR-975, SUB 40	(09/22/2015)
(Colonial Village at Stone Pointe Apts.)	WR-975, SUB 41	(09/22/2015)
(Colonial Village at South Tryon Apts.)	WR-975, SUB 42	(09/22/2015)
(Colonial Village at Mill Creek Apts.)	WR-975, SUB 43	(12/22/2015)
(Glen Eagles Apartments)	WR-975, SUB 44	(12/22/2015)
CM Apartments, LLC	WR-1785, SUB 1	(10/21/2015)
(Longview Meadow Apartments)		
CMF 7 Portfolio, LLC		
(Colonial Grand at Huntersville Apts.)	WR-976, SUB 11	(09/22/2015)
(Colonial Village at Greystone Apts.)	WR-976, SUB 12	(09/22/2015)
CMF 15 Portfolio, LLC		
(Colonial Grand at Crabtree Apts.)	WR-955, SUB 30	(09/22/2015)
(Colonial Grand at Arringdon Apts.)	WR-955, SUB 31	(11/10/2015)
(Colonial Grand at Patterson Place Apts.)	WR-955, SUB 32	(09/22/2015)
(Colonial Grand at Mallard Lake Apts.)	WR-955, SUB 33	(09/22/2015)
(Colonial Grand at Beverly Crest Apts.)	WR-955, SUB 34	(09/22/2015)
(Colonial Grand at Mallard Creek Apts.)	WR-955, SUB 35	(09/22/2015)
CMLT 2008-LS1 Guilford Living, LLC	WR-1407, SUB 3	(08/12/2015)
(Ashley Oaks Apartments)		
CND Duraleigh Woods, LLC	WR-741, SUB 6	(12/07/2015)
(Duraleigh Woods Apartments)		
CND Sailboat Bay, LLC	WR-737, SUB 6	(12/28/2015)
(Sailboat Bay Apartments)		
CoHeritage Oake Point, LLC	WR-1316, SUB 3	(08/04/2015)
(Oak Pointe Apartments)		

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ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Colonial Alabama Limited Partnership		
(Colonial Grand at Research Park Apts.)	WR-437, SUB 51	(09/21/2015)
(Colonial Grand at Matthews Com. Apts.)	WR-437, SUB 52	(09/21/2015)
(Colonial Grand at Ayrsley Apts.)	WR-437, SUB 53	(09/21/2015)
(The Enclave Apartments)	WR-437, SUB 54	(09/21/2015)
(CR at South End Apartments)	WR-437, SUB 55	(09/21/2015)
(Colonial Village at Chancellor Park Apt.)	WR-437, SUB 56	(09/21/2015)
(Colonial Grand at Univ. Center Apts.)	WR-437, SUB 57	(09/21/2015)
(Colonial Grand at Cornelius Apts.)	WR-437, SUB 58	(12/22/2015)
Colonial NC, LLC	WR-1284, SUB 4	(08/25/2015)
(Colonial Townhouse Apartments)		
Concord Warwick, LLC	WR-526, SUB 5	(11/09/2015)
(Concord Apartments)		
Cornerstone NC Operating LP	WR-973, SUB 4	(10/12/2015)
(Colonial Grand at Autumn Park Apts.)		
Courtney Estates Grand, LLC	WR-729, SUB 6	(09/11/2015)
(The Crossings at Alexander Pl. Apts.)		
Crabtree Village Apartment Investors, LLC	WR-1630, SUB 1	(09/14/2015)
(Solis Crabtree Apartments, Phase 1)		
Crescent Commons Apartments, LLC	WR-460, SUB 8	(08/18/2015)
(Crescent Commons Apartments)		
Crescent Oaks Apartments, LLC	WR-465, SUB 8	(07/31/2015)
(Crescent Oaks Apartments)		
Crestmont at Ballantyne Apartments, LLC	WR-335, SUB 11	(07/27/2015)
(Legacy at Ballantyne Apartments)		
CRLP Bruckhaus Street, LLC	WR-1060, SUB 4	(09/21/2015)
(Colonial Grand at Brier Creek Apts.)		
CRLP Crescent Lane, LLC	WR-977, SUB 5	(09/22/2015)
(Colonial Village at Matthews Apts.)		
Crossing at Chester Ridge, LLC	WR-1560, SUB 1	(09/21/2015)
(Crossing at Chester Ridge Apts.)		
Crown Ridge Partners, LLC	WR-818, SUB 5	(10/06/2015)
(Grand Terraces Apartments)		

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ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
CSP Community Owner, LLC		
(Camden Governor's Village Apts.)	WR-909, SUB 22	(09/11/2015)
(Camden Dilworth Apartments)	WR-909, SUB 23	(09/11/2015)
(Camden Ballantyne Apartments)	WR-909, SUB 24	(09/11/2015)
(Camden Sedgebrook Apartments)	WR-909, SUB 25	(09/11/2015)
(Camden Westwood Apartments)	WR-909, SUB 26	(09/11/2015)
(Camden Lake Pine Apartments)	WR-909, SUB 27	(09/11/2015)
(Camden Manor Park Apartments)	WR-909, SUB 28	(09/11/2015)
(Camden Reunion Park Apartments)	WR-909, SUB 29	(09/11/2015)
CSP Highland Oaks, LLC	WR-1137, SUB 4	(11/02/2015)
(Highland Oaks Apartments)		
CSP Hunt's View, LLC	WR-1217, SUB 4	(08/18/2015)
(Hunt's View Apartments)		
Cumberland Cove, LLC	WR-1771, SUB 1	(09/25/2015)
(Cumberland Cove Apartments)		
CWS Carmel Valley Associates, LP, et al.	WR-1267, SUB 4	(10/12/2015)
(Marquis of Carmel Valley Apartments)		
CWS Palm Valley Ballantyne, LP, et al.	WR-343, SUB 5	(04/06/2015)
(The Preserve at Ballantyne Commons Apts.)		
David Maggard	WR-632, SUB 6	(11/16/2015)
(Quiet Hollow Mobile Home Park)		
Deerwood Apartments, LLC		
(Twin City Apartments)	WR-853, SUB 5	(02/02/2015)
(Twin City Apartments)	WR-853, SUB 6	(11/13/2015)
Delta Crossing NC Partners, LLC	WR-1219, SUB 3	(11/23/2015)
(Delta Crossing Apartments)		
DLS Kernersville, LLC		
(Abbotts Creek Apartments)	WR-19, SUB 11	(02/17/2015)
(Abbotts Creek Apartments)	WR-19, SUB 12	(11/03/2015)
Donathan/Briarleigh Park Properties, LLC	WR-797, SUB 8	(11/03/2015)
(Briarleigh Park Apartments)		
Donathan Cary Limited Partnership	WR-558, SUB 9	(07/29/2015)
(Hyde Park Apartments)		
DPG Investments, LLC	WR-1673, SUB 1	(09/29/2015)
(Willow Creek Mobile Home Park)		
DPR Cary, LLC	WR-1743, SUB 1	(11/16/2015)
(The Reserve at Cary Park Apts.)		
DPR Parc at University Tower, LLC	WR-1384, SUB 3	(08/20/2015)
(Parc at University Tower Apartments)		

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Company	Docket No.	Date
DRA Lodge at Mallard Creek, LP *(The Lodge at Mallard Creek Apts.)*	WR-854, SUB 7	(08/20/2015)
DRA Woodland Park, LP *(Woodland Park Apartments)*	WR-861, SUB 6	(08/19/2015)
Dry Ridge Properties, LLC, et al. *(Mountain View Mobile Home Park)*	WR-867, SUB 4	(10/05/2015)
Durham Holdings I, LLC *(Amber Oaks Apartments)*	WR-1467, SUB 2	(10/19/2015)
Durham Mews Section II Associates, LLC *(The Mews Apartments, Section II)*	WR-884, SUB 4	(10/15/2015)
Durham Section I Associates, LLC *(The Mews Apartments, Section I)*	WR-883, SUB 4	(10/15/2015)
Dutch Village Apartments, LLC *(Twin City Townhomes)*	WR-865, SUB 5	(02/02/2015)
E. O. Johnson Properties LP *(Sedgefield Square Apartments)*	WR-1191, SUB 3	(10/08/2015)
Eagle Point Village Apartments, LLC *(Eagle Point Village Apartments)*	WR-671, SUB 7	(06/22/2015)
East Pointe Partners, LLC *(Stanford Reserve Apartments)*	WR-966, SUB 4	(10/06/2015)
East TBR Hamptons Owner, LLC *(The Hamptons at R. T. P. Apts.)*	WR-1370, SUB 2	(07/30/2015)
East 54 Associates, LLC *(East 54 Apartments)*	WR-1752, SUB 1	(07/06/2015)
Echo Forest, LLC *(Legacy Arboretum Apartments)*	WR-368, SUB 11	(07/27/2015)
Edgeline Residential, LLC *(Edgeline Flats on Davidson Apts.)*	WR-1567, SUB 1	(02/09/2015)
EEA-Wildwood, LLC *(Wildwood Apartments)*	WR-629, SUB 7	(09/25/2015)
Elizabeth Square Acquisition Corp. *(Elizabeth Square Apartments)*	WR-1086, SUB 4	(12/22/2015)
Elon Crossing, LLC *(Elon Crossing Apartments)*	WR-1535, SUB 2	(08/03/2015)
Emmett Ramsey *(Emma Hills Mobile Home Park)*	WR-796, SUB 6	(10/05/2015)
Erwin Hills Park, LLC *(Erwin Hills Mobile HP)*	WR-946, SUB 6	(07/28/2015)
Estates at Charlotte I, LLC *(1420 Magnolia Apartments)*	WR-73, SUB 7	(08/03/2015)

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Company	Docket No.	Date
Everest Brampton, LP	WR-1091, SUB 5	(11/10/2015)
(Brampton Moors Apartments)		
Fairfield Chason Ridge, LLC	WR-1414, SUB 2	(09/10/2015)
(Chason Ridge Apartments)		
Fairfield Courtney Place, LLC	WR-1598, SUB 2	(11/09/2015)
(Courtney Place Apartments)		
Fairfield Fairington, LLC	WR-1418, SUB 3	(11/09/2015)
(The Fairington Apartments)		
Fairfield Marina Shores, LLC	WR-1420, SUB 3	(10/06/2015)
(Marina Shores Waterfront Apts.)		
Fairfield Trinity Park, LLC		
(Trinity Park Apartments)	WR-1597, SUB 1	(03/09/2015)
(Trinity Park Apartments)	WR-1597, SUB 2	(09/10/2015)
Falls River Apartments, LLC	WR-1110, SUB 5	(08/17/2015)
(Bell Falls River Apartments)		
FASF, LLC	WR-999, SUB 6	(09/09/2015)
(Cedar Trace IV Apartments)		
FCP West Village Phase I Owner, LLC	WR-1251, SUB 4	(08/19/2015)
(West Village Apartments)		
FCP West Village Phase III, LLC	WR-1751, SUB 1	(08/19/2015)
(West Village Apartments, Phase III)		
Featherstone Village Apartments	WR-375, SUB 9	(10/20/2015)
(Featherstone Village Apartments)		
Forest Hill Apartments, LLC	WR-34, SUB 11	(03/02/2015)
(The Reserve at Forest Hills Apts.)		
Forestdale W99 LAP, LLC	WR-1847, SUB 1	(09/01/2015)
(Hawthorne at Forestdale Apartments)		
Fortune Bay Associates, LLC	WR-785, SUB 9	(07/27/2015)
(Forest Pointe Apartments)		
Fuller Street Development, LLC	WR-726, SUB 6	(08/19/2015)
(West Village Expansion Apartment)		
Fund Asbury Village, LLC	WR-1211, SUB 1	(09/10/2015)
(Camden Asbury Village Apartments)		
Fund II Meadows, LLC, et al.	WR-846, SUB 11	(08/21/2015)
(The Meadows Apartments, Phase II)		
Fund III Bridford Apartments, LLC	WR-1120, SUB 4	(08/17/2015)
(Bell Bridford Apartments)		
Fund III Cranbrook Apartments, LLC, et al.	WR-1076, SUB 5	(08/17/2015)
(Bell Biltmore Park Apartments)		

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Company	Docket No.	Date
Fund IX CP Charlotte, LLC		
(Matthews Crossing Apartments)	WR-691, SUB 9	(02/23/2015)
(Matthews Crossing Apartments)	WR-691, SUB 10	(08/07/2015)
Fund Southline, LLC	WR-1789, SUB 1	(09/11/2015)
(Camden Southline Apartments)		
Fund X EBC Raleigh, LLC	WR-1209, SUB 3	(08/06/2015)
(Exchange at Brier Creek Apts.)		
G Partnership, LP	WR-1262, SUB 2	(10/12/2015)
(The Landings Apartments)		
G&I VIII Brier Creek, LLC	WR-1650, SUB 1	(09/30/2015)
(Crest at Brier Creek Apts.)		
Galleria Partners II, LLC	WR-925, SUB 3	(08/21/2015)
(The Crest Apartments at Galleria)		
Gateway West-FCA, LLC	WR-1561, SUB 1	(09/28/2015)
(Gateway West Uptown Flats Apts.)		
Genesis Partners, LLC		
(Neuse Mobile Home Park)	WR-323, SUB 11	(03/02/2015)
(Treeside Mobile Home Park)	WR-323, SUB 12	(08/17/2015)
George Travis Dickey	WR-1584, SUB 1	(10/08/2015)
(Twin Branch Mobile Home Park)		
GF Property Funding Corp.	WR-1534, SUB 2	(11/09/2015)
(Garrett West Apartments)		
GGT Whitehall Venture NC, LLC	WR-1338, SUB 3	(11/02/2015)
(Whitehall Parc Apartments)		
Ginkgo BVG, LLC	WR-1519, SUB 2	(10/12/2015)
(Boundary Village Apartments)		
Ginkgo Kimmerly, LLC	WR-1729, SUB 1	(09/23/2015)
(Kimmerly Glen Apartments)		
Ginkgo OBC, LLC	WR-1558, SUB 3	(10/05/2015)
(Aurora Apartments)		
Ginkgo SAC, LLC	WR-1691, SUB 1	(11/30/2015)
(Salem Crest Apartments)		
Glenwood Raleigh Apartments, LLC	WR-1833, SUB 1	(08/10/2015)
(Sterling Glenwood Apartments)		
Golden Triangle #1, LLC	WR-1400, SUB 2	(08/21/2015)
(Crest at Graylyn Apartments)		
Goldsboro Apartments Investors, LLC	WR-1131, SUB 1	(03/30/2015)
(The Reserve at Bradbury Place Apts.)		
Gordon F. & Susan C. Duckett	WR-928, SUB 7	(08/13/2015)
(Forest Ridge Mobile Home Park)		

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Company	Docket No.	Date
GQ Allerton, LLC *(Allerton Place Apartments)*	WR-1608, SUB 2	(09/01/2015)
GQ Cary Brook, LLC *(The Reserve at Magnolia Ridge Apts.)*	WR-1604, SUB 1	(09/01/2015)
GQ Lynn Lake, LLC *(Lynn Lake Apartments)*	WR-1726, SUB 1	(09/01/2015)
GQ Millbrook, LLC *(Millbrook Apartments)*	WR-1725, SUB 1	(09/01/2015)
Grace Park Development, LLC *(Grace Park Apartments)*	WR-893, SUB 6	(09/30/2015)
Granite Ridge Investments, LLC *(Granite Ridge Apartments)*	WR-295, SUB 6	(12/15/2015)
Gregory S. & Narumon F. Cogdill *(Rockola Mobile Home Park)*	WR-935, SUB 7	(07/28/2015)
Grey Eagle MHP, LLC *(Grey Eagle Mobile Home Park)*	WR-1546, SUB 2	(10/05/2015)
Greystone WW Company, LLC *(Greystone at Widewaters Apartments)*	WR-517, SUB 7	(08/17/2015)
Grove Associates Limited Partnership *(Whitehall Estates Apartments)*	WR-1464, SUB 1	(07/06/2015)
GS Endinborough Commons, LLC *(Edinborough Commons Apts.)*	WR-475, SUB 10	(11/18/2015)
GS Endinborough Park, LLC *(Edinborough at the Park Apartments)*	WR-476, SUB 8	(10/05/2015)
GS Village, LLC *(The Village Apartments)*	WR-564, SUB 10	(10/14/2015)
Guardian Tryon Village, LLC *(Windsor at Tryon Village Apts.)*	WR-1335, SUB 3	(12/28/2015)
Hamilton Florida Partners, LLC *(Hamilton Square Apartments)*	WR-841, SUB 3	(10/08/2015)
Hampton Ridge Partners, LLC *(Victoria Park Apartments)*	WR-901, SUB 5	(10/06/2015)
Hanover Terrace, LLC *(Hanover Terrace Apartments)*	WR-622, SUB 8	(08/04/2015)
Harris Blvd. Communities I, LLC *(Worthington Luxury Apartments)*	WR-478, SUB 2	(10/26/2015)
HART Addison Park, LLC *(Addison Park Apartments)*	WR-1029, SUB 2	(10/13/2015)
Hawkins Street Holdings, LLC *(Spectrum Apartments)*	WR-1011, SUB 5	(11/09/2015)

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Company	Docket No.	Date
Hawthorne-Charleston Strickland, LLC, et al.	WR-1778, SUB 1	(11/04/2015)
(Hawthorne Glen at Strickland Apts.)		
Hawthorne-Midway Dunhill, LLC	WR-1430, SUB 2	(09/29/2015)
(Hawthorne at the Trace Apts.)		
Hawthorne-Midway Meridian, LLC	WR-1386, SUB 2	(07/13/2015)
(Hawthorne at the Trail Apartments)		
Hawthorne-Midway Stratford, LLC, et al.	WR-1553, SUB 2	(09/23/2015)
(Hawthorne at the Parkway Apts.)		
Hawthorne-Midway Summerwood, LLC	WR-1194, SUB 5	(12/01/2015)
(Summerwood Apartments)		
Hayleigh Village Apartments, LLC	WR-1152, SUB 3	(10/20/2015)
(Hayleigh Village Apartments)		
Heather Park Limited Partnership	WR-94, SUB 2	(10/21/2015)
(Heather Park Apartments)		
Heatherwood Florida Partners, LLC	WR-930, SUB 2	(10/08/2015)
(Heatherwood Trace Apartments)		
Heinmiller Investments, LLC	WR-1092, SUB 5	(10/06/2015)
(Broadview Mobile Home Park)		
Heritage Arden I, LLC, et al.	WR-1298, SUB 3	(07/29/2015)
(Arden Woods Apartments)		
Heritage Circle Apartments, LLC	WR-1625, SUB 1	(11/23/2015)
(Heritage Circle Apartments)		
Heritage Gardens, LLC	WR-1533, SUB 1	(09/02/2015)
(Ardmore Heritage Apartments)		
Heritage Williamsburg I, LLC, et al.	WR-1299, SUB 3	(09/10/2015)
(Williamsburg Manor Apartments)		
Hickory Grove NC Partners, LLC		
(Cameron at Hickory Grove Apts.)	WR-1435, SUB 2	(02/16/2015)
(Cameron at Hickory Grove Apts.)	WR-1435, SUB 3	(11/23/2015)
Hidden Creek Village Apartments, LLC	WR-377, SUB 9	(06/01/2015)
(Hidden Creek Village Apartments)		
Highland Quarters, LLC	WR-520, SUB 9	(10/12/2015)
(Muirfield Village Apartments)		
Highlands at Olde Raleigh, LLC	WR-1443, SUB 2	(09/16/2015)
(Highlands at Olde Raleigh Apts.)		
Hillsborough Apartments Partners, LLC		
(Patriot's Pointe Apartments)	WR-1206, SUB 2	(02/16/2015)
(Patriot's Pointe Apartments)	WR-1206, SUB 3	(08/04/2015)
Hillsborough Seminole, LLC	WR-787, SUB 4	(12/29/2015)
(Ashford Lakes Apartments)		

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Company	Docket No.	Date
HMS SouthPark Residential, LLC		
(The Residence at SouthPark Apts.)	WR-668, SUB 4	(03/02/2015)
(The Residence at SouthPark Apts.)	WR-668, SUB 5	(09/01/2015)
Holiday City MHC, LLC	WR-1454, SUB 1	(09/23/2015)
(Holiday City Mobile Home Park)		
Holiday Park, LLC	WR-1463, SUB 1	(03/16/2015)
(Hillsborough West Village Apts.)		
Holly NC, LLC	WR-1290, SUB 4	(08/25/2015)
(Holly Hills Apartments)		
Horizon Acquisition #3, LLC	WR-1325, SUB 1	(07/13/2015)
(Heritage Apartments)		
Horizon Development Properties, Inc.	WR-1075, SUB 2	(08/31/2015)
(Mill Pond Apartments)		
HRTBH Timber Creek, LLC	WR-1761, SUB 1	(09/09/2015)
(Timber Creek Apartments)		
HTC Preston Reserve, LLC, et al.	WR-1180, SUB 4	(08/17/2015)
(Bell Preston Reserve Apartments)		
Inman Park Investment Group, Inc.	WR-383, SUB 12	(08/18/2015)
(Inman Park Apartments)		
Innisbrook Village, LLC	WR-1278, SUB 3	(10/20/2015)
(Innisbrook Village Apartments)		
IRT Lenoxplace Apartments Owner, LLC	WR-1713, SUB 1	(08/07/2015)
(Lenox at Garners Station Apts.)		
James M. Dowtin	WR-1577, SUB 2	(08/05/2015)
(Tall Pines Mobile Home Park)		
JLB Southpark Apartments, LLC	WR-1832, SUB 1	(09/15/2015)
(Allure Apartments)		
Joe T. Jones & JoAnn Jones	WR-1677, SUB 1	(08/13/2015)
(Asbury Acres Mobile Home Park)		
Junction 1504, LLC	WR-1559, SUB 1	(10/19/2015)
(Junction 1504 Apartments)		
K Partnership, LLC	WR-1631, SUB 1	(08/19/2015)
(Hampton Downs Apartments)		
KBS Legacy Partners Wesley, LLC	WR-1379, SUB 1	(01/12/2015)
(Wesley Village Apartments)		
KC Realty Investments, LLC		
(Glimmer Mobile Home Park)	WR-950, SUB 7	(07/28/2015)
(Woodland Heights Mobile HP)	WR-950, SUB 8	(07/28/2015)

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
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Company	Docket No.	Date
Kings Park, LLC	WR-349, SUB 12	(09/28/2015)
(Redcliffe at Kenton Place Apts.)		
Kingswood NC, LLC	WR-987, SUB 3	(09/08/2015)
(Kingswood Mobile Home Park)		
Koury Corporation	WR-595, SUB 7	(01/12/2015)
(Village Lofts Apartments)		
KUWA, LLC	WR-843, SUB 6	(02/23/2015)
(Northstone Apartments)		
Lakeshore Apartments, LLC	WR-649, SUB 7	(09/09/2015)
(The Lodge at Lakeshore Apts.)		
Lambeth MHC, LLC	WR-1364, SUB 1	(07/06/2015)
(Lambeth Mobile Home Park)		
Landmark at Chesterfield, LP	WR-1174, SUB 3	(10/06/2015)
(Lankmark at Chesterfield Apts.)		
Landmark at Eagle Landing, LP	WR-1465, SUB 1	(10/06/2015)
(Landmark at Eagle Landing Apts.)		
Landmark at Greenbrooke Commons, LLC	WR-1489, SUB 1	(10/06/2015)
(Landmark at Greenbrooke Commons Apts.)		
Landmark at Watercrest, LP	WR-1466, SUB 1	(10/06/2015)
(Landmark at Watercrest Apts.)		
LaSalle NC, LLC	WR-1286, SUB 4	(08/25/2015)
(Duke Manor Apartments)		
LAT Battleground Park, LLC	WR-1550, SUB 1	(10/06/2015)
(Landmark at Battleground Park Apts.)		
LAT Mallard Creek, LLC	WR-1490, SUB 1	(10/06/2015)
(Landmark at Mallard Creek Apts.)		
LAT University Place, LLC	WR-1491, SUB 1	(10/06/2015)
(Landmark at Monaco Gardens Apts.)		
Lawndale Associates, LLC	WR-1253, SUB 2	(02/02/2015)
(Winstead Commons Apts.)		
Lees Chapel Partners, LLC		
(Chapel Walk Apartments)	WR-875, SUB 21	(09/09/2015)
(Cross Creek Apartments)	WR-875, SUB 22	(09/09/2015)
Legacy at Twin Oaks, LLC	WR-1353, SUB 3	(08/17/2015)
(Twin Oaks Apartments)		
Legacy Cornelius, LLC	WR-1388, SUB 3	(07/27/2015)
(Legacy Cornelius Apartments)		
Legacy Matthews, LLC	WR-568, SUB 9	(07/28/2015)
(Legacy Matthews Apts.)		

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Legacy Oaks Apartments, LP	WR-972, SUB 8	(09/28/2015)
(Alta Legacy Oaks Apartments)		
Lincoln Green Apartments, LLC	WR-527, SUB 7	(08/19/2015)
(Lincoln Green Apartments)		
Litchford Park, LLC	WR-588, SUB 9	(08/20/2015)
(The Park at North Ridge Apts.)		
Lone Oak, LLC	WR-1084, SUB 4	(11/02/2015)
(Lone Oak Mobile Home Park)		
LSREF3 Bravo (Charlotte), LLC		
(Harris Pond Apartments)	WR-1718, SUB 6	(08/19/2015)
(Mallard Creek Apartments)	WR-1718, SUB 7	(08/20/2015)
(Northlake Apartments)	WR-1718, SUB 8	(08/20/2015)
(Crossing at Quail Hollow Apts.)	WR-1718, SUB 9	(08/21/2015)
(Providence Court Apartments)	WR-1718, SUB 10	(08/20/2015)
(Sharon Crossing Apartments)	WR-1718, SUB 11	(08/20/2015)
LSREF3 Bravo (Raleigh), LLC		
(Cooper Mill Apartments)	WR-1717, SUB 7	(08/19/2015)
(Oaks at Weston Apartments)	WR-1717, SUB 8	(08/20/2015)
(The Meadows of Kildare Apartments)	WR-1717, SUB 9	(08/20/2015)
(The Reserve at Lake Lynn Apts.)	WR-1717, SUB 10	(08/20/2015)
(Walnut Creek Apartments)	WR-1717, SUB 11	(08/20/2015)
(Spring Forest Apartments)	WR-1717, SUB 12	(08/21/2015)
M Realty, LLC	WR-1040, SUB 4	(09/14/2015)
(Wellington Mobile Home Park)		
Mallard Green, LLC	WR-1259, SUB 4	(08/31/2015)
(Mallard Green Apartments)		
Marsh Realty Company		
(Briarcreek Apartments)	WR-1154, SUB 15	(08/11/2015)
(Biscayne Apartments)	WR-1154, SUB 16	(08/11/2015)
(Park Place Apartments)	WR-1154, SUB 17	(08/11/2015)
Mayfaire Apartments, LLC	WR-345, SUB 7	(07/30/2015)
(Mayfaire Apartments)		
McArthur Partners, LLC	WR-1292, SUB 3	(07/13/2015)
(The Heights at McArthur Park Apts., Ph. 1)		
McArthur Partners II, LLC	WR-1124, SUB 4	(07/13/2015)
(The Heights at McArthur Park Apts., Ph. II)		
MCP Ashton South End, LLC	WR-1819, SUB 1	(09/01/2015)
(Ashton Southend Apartments)		
Mellow Field Partners, LLC	WR-1564, SUB 2	(08/03/2015)
(The Avenues Apartments)		

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Meridian at Harrison Pointe, LLC	WR-1568, SUB 1	(09/29/2015)
(Meridian at Harrison Pointe Apts.)		
Metro 808 Charlotte, LLC	WR-1714, SUB 1	(12/07/2015)
(Metro 808 Apartments)		
MFREVF-Piedmont, LLC	WR-1190, SUB 3	(09/14/2015)
(The Piedmont at Ivy Meadow Apts.)		
Michael J. Schrader	WR-795, SUB 3	(08/18/2015)
(Campus West Apartments)		
Mid-America Apartments, LP		
(1225 South Church Apartments)	WR-22, SUB 53	(04/28/2015)
(Hue Apartments)	WR-22, SUB 65	(12/21/2015)
(1225 South Church Apartments)	WR-22, SUB 66	(12/21/2015)
(The Preserve at Brier Creek Apts.)	WR-22, SUB 67	(12/21/2015)
(Providence at Brier Creek Apts.)	WR-22, SUB 68	(12/21/2015)
(The Corners at Crystal Lake Apts.)	WR-22, SUB 69	(12/21/2015)
Midtown Green Realty Company, LLC	WR-1782, SUB 1	(12/01/2015)
(Midtown Green Apartments)		
MLVI Pointe at Crabtree Apartments, LLC	WR-1796, SUB 2	(12/14/2015)
(The Pointe at Crabtree Apartments)		
M.O.R.E., LLC	WR-400, SUB 1	(09/21/2015)
(Chesney Woods Apartments)		
Morreene, LLC	WR-1289, SUB 4	(08/25/2015)
(Chapel Tower Apartments)		
Morrisville Associates, LLC	WR-879, SUB 4	(10/15/2015)
(Crabtree Crossing Townhomes Apts.)		
Moss Enterprises, Inc. of Asheville		
(Crownpointe Mobile Home Park)	WR-924, SUB 14	(08/31/2015)
(Mosswood/Twin Oaks MHP)	WR-924, SUB 15	(08/31/2015)
Mosteller Apartments, LLC	WR-1404, SUB 3	(07/21/2015)
(Estates at Legends Apartments)		
Mountain High Property Management, LLC	WR-1556, SUB 2	(10/05/2015)
(Becky's Mobile Home Park)		
MP Artisan Brightleaf Apartments, LLC	WR-1478, SUB 3	(12/22/2015)
(Artisan at Brightleaf Apartments)		
MP Beacon Glen, LLC	WR-1665, SUB 2	(12/14/2015)
(Beacon Glen Apartments)		
MP Regatta, LLC	WR-1318, SUB 3	(08/21/2015)
(Regatta at Lake Lynn Apartments)		
MRP Laurel Oaks, LLC	WR-507, SUB 4	(03/03/2015)
(Laurel Oaks Apartments)		

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ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
MRP Laurel Springs, LLC	WR-506, SUB 5	(03/03/2015)
(Laurel Springs Apartments)		
MRWR, LLC	WR-832, SUB 8	(08/25/2015)
(Atrium Apartments)		
NationsProperties, LLC		
(Arbor Crest II Apartments)	WR-821, SUB 1	(05/11/2015)
(Arbor Crest II Apartments)	WR-821, SUB 2	(10/14/2015)
New Haw Creek Associates, LLC	WR-624, SUB 4	(10/15/2015)
(New Haw Creek Mews Apts.)		
North Carolina Rental Parks Associates, Ltd.	WR-1070, SUB 5	(08/05/2015)
(Whispering Pines MHP)		
North Forsyth MHC, LLC	WR-1469, SUB 1	(07/06/2015)
(North Forsyth Mobile Home Park)		
North Timbers, LLC		
(Oak City Apartments)	WR-285, SUB 8	(02/09/2015)
(Oak City Apartments)	WR-285, SUB 9	(08/18/2015)
Northlake Madison Properties, LLC, et al.	WR-1807, SUB 1	(08/05/2015)
(Madison Square Apartments)		
Northland Governor's Point, LLC		
(Governor's Point Apartments)	WR-1257, SUB 3	(04/20/2015)
(Governor's Point Apartments)	WR-1257, SUB 4	(09/08/2015)
Northland River Birch, LLC	WR-1258, SUB 3	(08/20/2015)
(River Birch Apartments, Phase II)		
Northland River Birch I, LLC	WR-1248, SUB 3	(08/20/2015)
(River Birch Apartments, Phase I)		
Northland Windemere, LLC	WR-1369, SUB 3	(09/08/2015)
(Windemere Apartments)		
Norwalk Street Partners, LLC		
(Norwalk Street Partners, LLC)	WR-653, SUB 7	(02/16/2015)
(Andover Park Apartments)	WR-653, SUB 8	(08/17/2015)
NR Holly Crest Property Owner, LLC	WR-1816, SUB 1	(11/30/2015)
(Holly Crest Apartments)		
NXRTBH Radbourne Lake, LLC	WR-1722, SUB 1	(08/18/2015)
(The Apartments at Radbourne Lake)		
Pacifica Mizell, LLC	WR-1676, SUB 1	(08/11/2015)
(Brannon Park Apartments)		
Parkside Drive, LLC	WR-1218, SUB 4	(09/21/2015)
(CG at Brier Falls Apartments)		
Passco Brier Creek DST	WR-1614, SUB 2	(10/13/2015)
(Carrington at Brier Creek Apts.)		

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ORDER APPROVING TARIFF REVISION
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Company	Docket No.	Date
Passco Columns DST	WR-1633, SUB 1	(11/24/2015)
(The Columns at Wakefield Apts.)		
Passco Encore at the Park DST	WR-1498, SUB 2	(11/17/2015)
(Encore at the Park Apartments)		
Passco Rivergate DST		
(Enclave at Rivergate Apartments)	WR-1433, SUB 2	(05/26/2015)
(Enclave at Rivergate Apartments)	WR-1433, SUB 3	(08/06/2015)
Passco Wakefield Glen DST	WR-1582, SUB 2	(12/15/2015)
(Wakefield Glen Apartments)		
PC Links, LLC	WR-1149, SUB 5	(12/22/2015)
(Links at Citiside Apartments)		
PG2, LLC	WR-1487, SUB 2	(09/09/2015)
(The Gardens at Anthony House Apts., Ph. 2)		
Pier Properties, LLC	WR-1138, SUB 2	(09/10/2015)
(Grassy Branch Mobile Home Park)		
Pine Glen Limited Partnership		
(Green of Pine Glen Apartments)	WR-1399, SUB 1	(04/27/2015)
(Green of Pine Glen Apartments)	WR-1399, SUB 2	(11/09/2015)
Pine Knoll Mobile Home Park, LLC	WR-1434, SUB 3	(08/24/2015)
(Pine Knoll Mobile Home Park)		
Piper Station Apartments, LLC	WR-1432, SUB 3	(11/02/2015)
(Ballantyne Commons Apts.)		
Pleasant Garden Apartments, LLC	WR-742, SUB 7	(09/09/2015)
(The Gardens at Anthony House Apts.)		
POAA II, LLC	WR-1282, SUB 4	(08/10/2015)
(Pines of Ashton Apartments)		
Post Apartment Homes, LP		
(Post Uptown Place Apartments)	WR-49, SUB 18	(07/13/2015)
(Post Park at Phillips Place Apts.)	WR-49, SUB 19	(07/15/2015)
Post Ballantyne, LLC	WR-1543, SUB 2	(07/14/2015)
(Post Ballantyne Apartments)		
Post Gateway Place, LLC	WR-1542, SUB 1	(07/14/2015)
(Post Gateway Place Apartments)		
Post Parkside at Wade, LP	WR-1440, SUB 2	(07/27/2015)
(Post Parkside at Wake Apartments)		
Post South End, LP	WR-1326, SUB 3	(07/14/2015)
(Post South End Apartments)		
PR Oberlin Court, LLC	WR-1179, SUB 3	(09/15/2015)
(The Apartments at Oberlin Court)		

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ORDER APPROVING TARIFF REVISION
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Company	Docket No.	Date
Privet Asheville, LLC	WR-1320, SUB 3	(08/19/2015)
(Eastwood Village Apartments)		
Providence Park Apartments I, LLC	WR-284, SUB 12	(08/11/2015)
(Providence Park Apartments)		
Prudential Insurance Company of America	WR-38, SUB 9	(09/29/2015)
(The Reserve Apartments)		
Quadbridge HML Owner, LLC	WR-1613, SUB 2	(11/24/2015)
(Highland Mill Lofts Apartments)		
RAIA Properties NC-2, LLC	WR-839, SUB 8	(08/07/2015)
(Birkdale Apartment Homes)		
RAIA Self-Storage Montville, LLC, et al.	WR-890, SUB 9	(08/07/2015)
(The Enclave at Crossroads Apartments)		
Ramblewood Venture, LLC	WR-1457, SUB 3	(11/03/2015)
(Allister North Hills Apts.)		
RCG Maybelle, LLC	WR-1646, SUB 1	(10/05/2015)
(Weaverville Commons Apartments)		
Red Chief, LLC	WR-722, SUB 6	(08/05/2015)
(Morehead Apartments)		
Redwood Landings, LLC		
(The Landing at Center Point Apts.)	WR-1681, SUB 1	(05/26/2015)
(The Landing at Center Point Apts.)	WR-1681, SUB 2	(08/06/2015)
REEP-MF Verde NC, LLC	WR-1087, SUB 5	(12/21/2015)
(North City 6 Apartments)		
Renhill II, LLC	WR-499, SUB 2	(10/13/2015)
(South Point Apartments)		
Ridgeview MHP, LLC	WR-712, SUB 7	(08/04/2015)
(Ridgeview Mobile Home Park)		
Riverbend of Asheville, LLC	WR-1296, SUB 3	(08/12/2015)
(Verde Vista Apartments)		
Riverwoods Raleigh Apartments, LLC	WR-1112, SUB 5	(08/03/2015)
(Sterling Forest Apartments)		
Robinhood Court Apartment Homes, LLC	WR-1051, SUB 6	(11/17/2015)
(Robinhood Court Apartments)		
Rockwood Road Apts., LLC	WR-964, SUB 5	(09/09/2015)
(Audubon Place Apartments)		
Roy & Betty Chapman	WR-1035, SUB 5	(10/05/2015)
(Twin Willows Mobile Home Park)		
Roy and Frances Ewing	WR-994, SUB 6	(08/13/2015)
(Pine Valley Mobile Home Park)		

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ORDER APPROVING TARIFF REVISION
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Company	Docket No.	Date
Ruby Lea Nicholas	WR-249, SUB 7	(04/28/2015)
(Woodcrest Mobile Home Park)		
RW Hawk Ridge, LLC	WR-1747, SUB 1	(11/13/2015)
(Hawk Ridge Apartments)		
Salem Ridge Apartments, LLC	WR-1096, SUB 4	(11/30/2015)
(Salem Ridge Apartments)		
Salem Village Apartments, LLC	WR-446, SUB 9	(08/11/2015)
(Salem Village Apartments)		
SBV-Greensboro-I, LLC		
(The Retreat II Apartments)	WR-1471, SUB 7	(09/08/2015)
(The Retreat I Apartments)	WR-1471, SUB 8	(09/10/2015)
SCG/TBR Venue Owner, LLC	WR-1799, SUB 1	(07/31/2015)
(Venue Apartments)		
Schrader Family Limited Partnership		
(Westcliffe Apartments)	WR-980, SUB 22	(08/18/2015)
(Green Castle Apartments)	WR-980, SUB 20	(08/18/2015)
(Peterson Park Apartments)	WR-980, SUB 23	(08/18/2015)
(Dover Apartments)	WR-980, SUB 24	(08/18/2015)
(Woodridge Apartments)	WR-980, SUB 25	(08/18/2015)
Schrader Properties, LLC	WR-1334, SUB 3	(08/18/2015)
(Campus Courtyard Apartments)		
Serenity Apartments at Greensboro, LLC	WR-1502, SUB 1	(07/27/2015)
(Serenity Apartments)		
SG-Waterford-Morrisville, LLC	WR-1157, SUB 4	(08/06/2015)
(The Waterford Apartments)		
Sherwood MHP, LLC	WR-1044, SUB 5	(08/11/2015)
(Sherwood Mobile Home Park)		
SHLP Chancery Village, LLC	WR-1204, SUB 4	(08/12/2015)
(Chancery Village at the Park Apts.)		
SHLP Gramercy Square at Ayrsley, LLC	WR-1184, SUB 4	(08/12/2015)
(Gramercy Square at Ayrsley Apts.)		
Silverton Marquis, LP	WR-422, SUB 11	(07/21/2015)
(Marquis at Silverton Apts.)		
Simpson Promenade Park, LLC	WR-876, SUB 4	(08/12/2015)
(Promenade Park Apartments)		
Simpson Woodfield Silos, LLC	WR-1526, SUB 2	(03/16/2015)
(Silos South End Apartments)		
Somerstone, LLC	WR-1557, SUB 2	(11/13/2015)
(Somerstone Apartments)		

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Company	Docket No.	Date
South End Apartments, LLC	WR-1173, SUB 4	(12/22/2015)
(Mosaic South End Apartments)		
South LaSalle Apartments, LLC	WR-1629, SUB 1	(11/09/2015)
(The Heights at LaSalle Apts.)		
South Square Owner, LLC	WR-1387, SUB 3	(11/09/2015)
(Alden Place at South Square Apts.)		
South Terrace Apartments North Carolina, LLC		
(South Terrace at Auburn Apts.)	WR-689, SUB 3	(04/06/2015)
(South Terrace at Auburn Apartments)	WR-689, SUB 4	(08/07/2015)
Southport Heather Ridge, LLC	WR-1082, SUB 3	(10/08/2015)
(Heather Ridge Apartments)		
Southwood Realty Company	WR-910, SUB 17	(08/06/2015)
(Catawba Apartments)		
Sovereign Development Company, LLC	WR-784, SUB 5	(01/26/2015)
(Willow Woods Apartments)		
Spinksville III, LLC	WR-727, SUB 5	(10/05/2015)
(Parkside Village Apartments)		
SPUS7 Tribute, LP	WR-1846, SUB 1	(10/05/2015)
(The Tribute Apartments)		
SRC Northwinds, Inc.	WR-1254, SUB 4	(08/24/2015)
(Northwinds I and II Apartments)		
Strawberry Hill Associates, LP	WR-293, SUB 10	(08/11/2015)
(Strawberry Hills Apartments)		
Summerlyn Holdings, LLC	WR-1689, SUB 1	(08/31/2015)
(Summerlyn Cottages Apartments)		
Summit Grandview, LLC	WR-547, SUB 5	(09/11/2015)
(Camden Grandview Apartments)		
Summit Street, LLC	WR-1741, SUB 1	(09/10/2015)
(District Flats Apartments)		
Sweetwater Meadows, LLC	WR-1375, SUB 3	(10/05/2015)
(Sweetwater Meadows Mobile HP)		
Swift Avenue-FCA, LLC	WR-1727, SUB 1	(11/16/2015)
(300 Swift Apartments)		
Tanglewood Lake Apts., LLC		
(Tanglewood Lake Apartments)	WR-1015, SUB 2	(02/10/2015)
(Tanglewood Lake Apartments)	WR-1015, SUB 3	(08/21/2015)
Terrace Mews, LLC	WR-1394, SUB 2	(11/25/2015)
(Terrace at Olde Battleground Apts.)		

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ORDER APPROVING TARIFF REVISION
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Company	Docket No.	Date
The Apartments at Crossroads, LLC *(Legacy Crossroads Apartments)*	WR-851, SUB 7	(07/28/2015)
The Carlisle at Delta Park, LLC *(The Carlisle at Delta Park Apts.)*	WR-388, SUB 5	(02/02/2015)
The Forest at Chasewood, LLC *(The Forest at Chasewood Apts.)*	WR-1504, SUB 2	(11/04/2015)
The Heritage at Arlington Apts., LLC *(The Heritage at Arlington Apts.)*	WR-1472, SUB 2	(10/19/2015)
The Legends at Hickory, LLC *(The Legends Apartments)*	WR-1409, SUB 3	(07/21/2015)
The Lofts at Charleston Row, LLC *(The Lofts at Charleston Row Apts.)*	WR-1313, SUB 2	(01/26/2015)
The Lofts at Little Creek, LLC *(The Lofts at Little Creek Apts.)*	WR-1626, SUB 1	(11/17/2015)
The Sanctuary at Charlotte, LLC *(Arcadia Student Living Apts.)*	WR-1758, SUB 1	(11/10/2015)
The Tradition at Mallard Creek, LLC *(Tradition at Mallard Creek Apts.)*	WR-353, SUB 4	(10/06/2015)
Thomas Newell & Johanna Page Rackley *(Buck's Mobile Home Park)*	WR-1437, SUB 2	(10/19/2015)
Thomasville Holly Hill, LLC *(Holly Hill Apartments)*	WR-1607, SUB 2	(11/25/2015)
Timber Crest Apartments, LLC *(Colonial Village at Timber Crest Apts.)*	WR-412, SUB 9	(09/21/2015)
TR Brier Creek, LLC *(The Jamison at Brier Creek Apts.)*	WR-1524, SUB 2	(09/11/2015)
TR Vinoy, LLC *(The Vinoy at Innovation Park Apts.)*	WR-1308, SUB 3	(10/13/2015)
Tradition at Stonewater Apartments, LLC *(Tradition at Stonewater Apartments)*	WR-1723, SUB 1	(08/21/2015)
TRB Oberlin Owner, LLC *(401 Oberlin Apartments)*	WR-1792, SUB 1	(07/31/2015)
Trellis Pointe, LLC *(Trellis Pointe Apartments)*	WR-14, SUB 2	(09/28/2015)
Treybrooke Village Apartments *(Treybrooke Village Apartments)*	WR-379, SUB 9	(10/20/2015)
Triangle Palisades of Asheville, LLC *(Palisades Apartments)*	WR-1787, SUB 1	(08/05/2015)

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Company	Docket No.	Date
Triangle Real Estate of Gastonia, LLC		
(Lakemist Apartments)	WR-1125, SUB 17	(08/04/2015)
(Huntersville Commons Apts.)	WR-1125, SUB 18	(08/04/2015)
(Eagle's Walk Apartments)	WR-1125, SUB 19	(08/04/2015)
(Woodbridge Apartments)	WR-1125, SUB 20	(08/04/2015)
(Pinetree Apartments)	WR-1125, SUB 21	(08/04/2015)
(Arborgate Apartments)	WR-1125, SUB 22	(08/04/2015)
Trinity Commons Apartments, LLC	WR-415, SUB 9	(09/21/2015)
(Colonial Grand at Trinity Commons Apts.)		
Triple Overlook, LLC	WR-1047, SUB 5	(07/27/2015)
(Triple Overlook Mobile HP)		
TS Brier Creek, LLC	WR-1620, SUB 1	(07/31/2015)
(Waterstone at Brier Creek Apts.)		
TS Creekstone, LLC	WR-1461, SUB 3	(11/17/2015)
(Woodfield Creekstone Apartments)		
TS New Bern, LLC	WR-1541, SUB 2	(07/31/2015)
(Fountains Southend Apartments)		
TS Westmont, LLC	WR-1462, SUB 3	(07/31/2015)
(Westmont Commons Apartments)		
Tucker Acquisition Corporation	WR-1039, SUB 5	(12/21/2015)
(The Devon Seven 12 Apartments)		
Umstead Raleigh Investors, LLC	WR-1772, SUB 1	(08/05/2015)
(Four Seasons at Umstead Park Apts.)		
VAC, LLLP		
(Princeton Apartments)	WR-831, SUB 119	(08/25/2015)
(Chesterfield Apartments)	WR-831, SUB 120	(08/25/2015)
(Eastwood Apartments)	WR-831, SUB 121	(08/25/2015)
(Oakwood Apartments)	WR-831, SUB 122	(08/25/2015)
(Briarwood Apartments)	WR-831, SUB 123	(08/25/2015)
(Rosewood Apartments)	WR-831, SUB 124	(08/25/2015)
Vanstory Apartments, LLC		
(Ashbrook Pointe Apartments)	WR-126, SUB 12	(02/16/2015)
(Ashbrook Pointe Apartments)	WR-126, SUB 13	(08/17/2015)
VCP Grand Oaks, LLC	WR-1648, SUB 1	(08/24/2015)
(Grand Oaks Apartments)		
VCP Lakes Meadowood, LLC	WR-1810, SUB 1	(08/24/2015)
(The Lakes on Meadowood Apts.)		
VCP The Ashland, LLC	WR-1811, SUB 1	(08/24/2015)
(The Ashland Apartments)		

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
Village Creek West Properties I, LLC	WR-713, SUB 2	(12/14/2015)
(Village Creek West Apartments)		
Village Rental Company, LLC	WR-468, SUB 6	(09/29/2015)
(Villager Apartments)		
Villas at Granite Ridge, LLC	WR-1788, SUB 1	(12/15/2015)
(The Villas at Granite Ridge Apts.)		
Vinings at Morehead, LLC	WR-1216, SUB 1	(10/27/2015)
(Vinings at Wildwood Apartments)		
VR Cedar Springs L.P.	WR-1158, SUB 3	(10/13/2015)
(Cedar Springs Apartments)		
VTT Carver Pond, LLC	WR-1509, SUB 2	(09/01/2015)
(Meriwether Place Apartments)		
Vyne Residential, LLC		
(The Vyne Apartments)	WR-1565, SUB 1	(02/09/2015)
(The Vyne Apartments)	WR-1565, SUB 2	(08/31/2015)
Wake Forest Apartments, LLC	WR-1510, SUB 1	(02/16/2015)
(Estates at Wake Forest Apartments)		
Walden/Greenfields Associates L.P.	WR-287, SUB 6	(02/24/2015)
(Sagebrook of Chapel Hill Apts.)		
Water Garden Village, LLC	WR-1315, SUB 3	(07/29/2015)
(Water Garden Village Apartments)		
Waterford at the Park DE, LLC	WR-1654, SUB 1	(10/14/2015)
(Waterford at the Park Apartments)		
Waverly Apartments, LLC		
(The Waverly Apartments)	WR-1293, SUB 3	(02/17/2015)
(The Waverly Apartments)	WR-1293, SUB 4	(07/27/2015)
Waypoint Stone Hollow Owner, LLC	WR-1611, SUB 2	(09/23/2015)
(Reserve at Stone Hollow Apartments)		
Weirbridge Village Apartments, LLC	WR-1168, SUB 4	(09/23/2015)
(Weirbridge Village Apartments)		
Wembley Apartments, LLC	WR-1017, SUB 2	(08/12/2015)
(Wembley Apartments)		
West Market Partners, LLC	WR-749, SUB 7	(09/09/2015)
(The Amesbury on West Market Apts.)		
West Morgan, LLC	WR-1428, SUB 3	(08/10/2015)
(927 West Morgan Apartments)		

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Westdale Arrowhead Crossing NC, LLC *(Arrowhead Crossing Apartments)*	WR-634, SUB 8	(07/31/2015)
Westdale Brentmoor, LLC *(Brentmoor Apartments)*	WR-1317, SUB 3	(07/30/2015)
Westdale Chase on Monroe NC, LLC *(Chase on Monroe Apartments)*	WR-635, SUB 8	(08/03/2015)
Westdale Galleria Village, LLC *(Galleria Apartment Homes)*	WR-1224, SUB 4	(07/29/2015)
Westdale Lenox, LLC *(Lenox at Patterson Place Apartments)*	WR-1351, SUB 3	(08/06/2015)
Westdale NC Summit Creek, Ltd. *(Johnston Creek Crossing Apts.)*	WR-826, SUB 7	(07/30/2015)
Westdale Peppertree, Ltd. *(Peppertree Apartments)*	WR-815, SUB 7	(07/30/2015)
Westdale Sabal Point NC, LLC *(Sabal Point Apartments)*	WR-636, SUB 8	(07/30/2015)
Westdale Willow Glen NC, LLC *(Willow Glen Apartments)*	WR-633, SUB 8	(07/31/2015)
Weston Parkway Partners, LLC *(Weston Corners Apartments)*	WR-1837, SUB 1	(08/03/2015)
Westridge Place, LLC *(Westridge Place Apartments)*	WR-637, SUB 3	(01/26/2015)
Whitehurst/Countryview MHP, LLC *(Whitehurst/Countryview MHP)*	WR-657, SUB 2	(09/28/2015)
Windsor Burlington, LLC *(Windsor upon Stonecrest Apartments)*	WR-594, SUB 4	(08/13/2015)
Windsor Landing Investments I, LLC, et al. *(Windsor Landing Apartments)*	WR-886, SUB 5	(09/02/2015)
WMCi Charlotte I, LLC *(Bexley Commons at Rosedale Apts.)*	WR-213, SUB 13	(07/01/2015)
WMCi Charlotte II, LLC *(Bexley Creekside Apartments)*	WR-230, SUB 12	(07/01/2015)
WMCi Charlotte III, LLC *(Bexley at Lake Norman Apts.)*	WR-258, SUB 12	(07/01/2015)
WMCi Charlotte IV, LLC *(Bexley Crossing at Providence Apts.)*	WR-269, SUB 12	(07/01/2015)
WMCi Charlotte V, LLC *(Bexley at Springs Farm Apts.)*	WR-340, SUB 11	(07/01/2015)
WMCi Charlotte VI, LLC *(Bexley Square at Concord Mills Apts.)*	WR-371, SUB 7	(07/20/2015)

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
WMCi Charlotte VII, LLC	WR-392, SUB 10	(07/01/2015)
(Bexley at Davidson Apartments)		
WMCi Charlotte VIII, LLC	WR-466, SUB 10	(07/01/2015)
(Bexley at Matthews Apartments)		
WMCi Charlotte IX, LLC	WR-467, SUB 10	(07/01/2015)
(Bexley Greenway Apartments)		
WMCi Charlotte X, LLC	WR-638, SUB 8	(07/01/2015)
(Bexley Harborside Apartments)		
WMCi Charlotte XI, LLC	WR-1117, SUB 5	(07/01/2015)
(Bexley at Steelecroft Apartments)		
WMCi Charlotte XII, LLC	WR-1136, SUB 4	(07/01/2015)
(Bexley Cloisters at Steelecroft Apts.)		
WMCi Charlotte XIII, LLC	WR-1189, SUB 3	(07/20/2015)
(Bexley Village at Concord Mills Apts.)		
WMCi Charlotte XIV, LLC	WR-1474, SUB 2	(07/20/2015)
(Bexley Village at Concord Mills II Apts.)		
WMCi Charlotte XV, LLC	WR-1486, SUB 2	(07/01/2015)
(Cielo Apartments)		
WMCi Raleigh I, LLC	WR-327, SUB 10	(07/20/2015)
(Bexley at Preston Apartments)		
WMCi Raleigh II, LLC	WR-317, SUB 10	(07/20/2015)
(Bexley Park Apartments)		
WMCi Raleigh III, LLC	WR-754, SUB 11	(07/20/2015)
(Bexley at Brier Creek Apartments)		
WMCi Raleigh IV, LLC		
(Bexley at Heritage Apts.)	WR-803, SUB 5	(01/26/2015)
(Bexley at Heritage Apts.)	WR-803, SUB 6	(07/20/2015)
WMCi Raleigh V, LLC	WR-949, SUB 7	(07/20/2015)
(Bexley at Carpenter Village Apts.)		
WMCi Raleigh VI, LLC	WR-1311, SUB 3	(07/20/2015)
(Bexley at Triangle Park Apartments)		
WMCi Raleigh VII, LLC	WR-1372, SUB 3	(07/20/2015)
(Bexley Panther Creek Apartments)		
WMCi Raleigh VIII, LLC	WR-1693, SUB 1	(07/20/2015)
(The Bristol at Park West Village Apts.)		
WMCi Raleigh IX, LLC	WR-1754, SUB 1	(07/20/2015)
(The Belmont Apartments)		
Woodlake Downs, LLC		
(Woodlake Downs Apartments)	WR-286, SUB 12	(02/09/2015)
(Woodlake Downs Apartments)	WR-286, SUB 13	(08/18/2015)

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
WRT Lake Brandt Property, LLC	WR-1368, SUB 2	(09/08/2015)
(Lake Brandt Apartments)		
WW Partnership		
(Blue's Crossing Apartments)	WR-850, SUB 5	(02/23/2015)
(Blue's Crossing Apartments)	WR-850, SUB 6	(09/28/2015)
(Woodland Creek Apartments)	WR-850, SUB 7	(09/14/2015)
Wynslow Park, LLC	WR-128, SUB 5	(09/21/2015)
(Gardens at Wynslow Park Apts.)		
Yanagi, LLC	WR-1475, SUB 1	(03/09/2015)
(Bryan Woods Apartment Homes)		
York Ridge Associates, LP		
(York Ridge Apartments)	WR-1451, SUB 1	(03/16/2015)
(York Ridge Apartments)	WR-1451, SUB 2	(08/24/2015)
18 Weather Hill Holdings, LLC	WR-1389, SUB 1	(11/02/2015)
(The Landing Apartments)		
330 West Tremont, LLC	WR-1548, SUB 2	(11/23/2015)
(335 Apartments)		
401 South Mint Street Apartment Investors, LLC	WR-1634, SUB 1	(09/16/2015)
(Element Uptown Apartments)		
425 Boylan, LLC	WR-1704, SUB 1	(11/24/2015)
(Devon 425 Apartments)		
1300 Knoll Circle Apartments Investors, LLC	WR-268, SUB 10	(08/20/2015)
(The Lodge at Southpoint Apts.)		
4200 Investments, LLC	WR-1177, SUB 2	(05/18/2015)
(Villagio Apartment Homes)		
7850 Homestead Village, LLC	WR-1197, SUB 3	(09/28/2015)
(Homestead Village Mobile HP)		

Avery Millbrook, LLC – WR-1020, SUB 10; Errata Order *(Millbrook Apartments I)* (01/06/2015)

Barrington Apartments, LLC -- WR-384, SUB 12; Reissued Order Approving Tariff Revision *(Legacy North Pointe Apartments)* (03/02/2015)

Bell Fund IV Morrison Apartments, LLC -- WR-1250, SUB 4; Reissued Order Approving Tariff Revision *(Bell Morrison Apartments)* (06/05/2015)

BNP/Savannah, LLC -- WR-474. SUB 7; Order Closing Docket *(Savannah Place Apts.)* (11/19/2015)

Durham Mews Section II Associates, LLC -- WR-884, SUB 4; Errata Order *(The Mews Apartments, Sec. II)* (12/02/2015)

Forestdale W99 LAP, LLC -- WR-1847, SUB 1; Reissued Order Approving Tariff Revision *(Hawthorne at Forestdale Apts.)* (09/15/2015)

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

Greystone WW Company, LLC -- WR-517, SUB 8; Order Closing Docket *(Greystone at Widewaters Apartments)* (10/22/2015)

Hawthorne-Charleston Strickland, LLC, et al. -- WR-1778, SUB 1; Reissued Order Approving Tariff Revision (11/06/2015)

LSREF3 Bravo (Raleigh), LLC -- WR-1717, SUB 7; Errata Order *(Copper Mill Apts.)* (09/23/2015)

Metro 808 Charlotte, LLC -- WR-1714, SUB 1; Reissued Order Approving Tariff Revision *(Metro 808 Apartments)* (12/10/2015)

Moss Enterprises, Inc. of Asheville -- WR-924, SUB 14, Errata Order *(Crownpointe Mobile HP)* (09/09/2015)

Northland Windemere, LLC -- WR-1369, SUB 2; Errata Order *(Windemere Apartments)* (01/09/2015)

Pine Knoll Mobile Home Park, LLC -- WR-1434, SUB 2; Order Closing Docket *(Pine Knoll Mobile Home Park)* (08/24/2015)

Roy & Betty Chapman -- WR-1035, SUB 4; Errata Order (01/06/2015)

Ruby Lea Nicholas -- WR-249, SUB 7; Reissued Order Approving Tariff Revision *(Woodcrest Mobile Home Park)* (04/29/2015)

St. Andrews Place Apartments, LLC -- WR-111, SUB 10; Errata Order *(Colonial Grand at Wilmington Apartments)* (01/06/2015)

Summit Street, LLC -- WR-1741, SUB 1; Errata Order *(District Flats Apartments)* (09/23/2015)

SVF Weston Lakeside, LLC -- WR-601, SUB 8; Reissued Order Approving Tariff Revision *(Apartments at Weston Lakeside)* (11/17/2015)

Tanglewood Lake Apts., LLC – WR-1015, SUB 3; Reissued Order Approving Tariff Revision *(Tanglewood Lake Apartments)* (12/10/2015)

Titan Colony, LLC -- WR-1395, SUB 3; Order Closing Docket *(Colony Apartments)* (11/06/2015)

Trinity Commons Apartments, LLC -- WR-415, SUB 8; Errata Order *(Colonial Grand at Trinity Commons Apartments)* (01/06/2015)

Village Creek West Properties I, LLC -- WR-713, SUB 2; Reissued Order Approving Tariff Revision *(Village Creek West Apartments)* (12/18/2015)

401 South Mint Street Apartment Investors, LLC -- WR-1634, SUB 1; Errata Order *(Element Uptown Apartments)* (09/23/2015)

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION (HWCCWA)
Orders Issued

Company	Docket No.	Date
Brentwood West Company, LLC	WR-1160, SUB 5	(07/29/2015)
(Brentwood West Apartments)		
Brook Dana, LLC	WR-1281, SUB 5	(08/10/2015)
(Brook Hill Apartments)		
CDC-Durham/ UC, LLC		
(Duke Villa Apartments)	WR-1100, SUB 7	(02/24/2015)
(Duke Court Apartments)	WR-1100, SUB 8	(02/24/2015)
(Duke Court Apartments)	WR-1100, SUB 9	(12/21/2015)
(Duke Villa Apartments)	WR-1100, SUB 10	(12/21/2015)
Central Pointe Apartments, LLC	WR-1479, SUB 3	(11/23/2015)
(Central Pointe Apartments)		
CSC Midtown, LLC	WR-1482, SUB 2	(10/12/2015)
(Midtown Park Apartments)		
Fairfield Oak Hollow, LLC	WR-1426, SUB 1	(09/14/2015)
(Oak Hollow Apartments)		
Fairfield Reafield Village, LLC	WR-1774, SUB 1	(08/19/2015)
(Reafield Village Apartments)		
FC Hidden Creek, LLC	WR-1724, SUB 2	(08/10/2015)
(North Oaks Landing Apartments)		
Fund II Meadows, LLC, et al.	WR-846, SUB 12	(08/21/2015)
(The Meadows Apartments, Phase I)		
Gorman Crossing, LLC	WR-1698, SUB 1	(09/28/2015)
(Gorman Crossing Apartments)		
Heritage Lakes I, LLC, et al.	WR-1202, SUB 3	(07/29/2015)
(The Lakes Apartments)		
Honeytree Acquisitions, LLC	WR-1545, SUB 2	(07/27/2015)
(Honeytree Apartments)		
HR Realty Company, LLC	WR-1161, SUB 5	(07/29/2015)
(Hunting Ridge Apartments)		
Hudson Redwood Lexington, LLC	WR-1823, SUB 1	(08/07/2015)
(Lexington Farms Apartments)		
Kensington Apartments, LLC	WR-1692, SUB 1	(09/15/2015)
(Kensington Park Apartments)		
Lake Clair, LLC	WR-1223, SUB 3	(06/22/2015)
(Lake Clair Apartments)		
Merriwood Associates L. P.	WR-1447, SUB 2	(10/05/2015)
(Merriwood Apartments)		
Mindy S. Solie	WR-1700, SUB 1	(09/15/2015)
(Anderson Apartments)		

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION (HWCCWA)
Orders Issued *(Continued)*

Company	Docket No.	Date
Montecito Company, LLC	WR-1162, SUB 5	(07/29/2015)
(Montecito Apartments)		
Penrith Townhomes, LLC	WR-1763, SUB 2	(08/04/2015)
(Woodland Creek Apartments)		
QR Realty Company, LLC	WR-1159, SUB 5	(07/29/2015)
(Quail Ridge Apartments)		
SBV-Greensboro II, LLC	WR-1690, SUB 2	(08/25/2015)
(LeMans at Lawndale Apts.)		
Schrader Family Limited Partnership		
(Smithdale Apartments)	WR-980, SUB 19	(08/18/2015)
(Cedar Point Apartments)	WR-980, SUB 21	(08/18/2015)
Seaboard Associates, LLC	WR-1694, SUB 1	(09/08/2015)
(Willow Ridge Apartments)		
Shellbrook Associates, LP	WR-1192, SUB 5	(08/03/2015)
(Shellbrook Apartments)		
Signature Place, LLC	WR-1074, SUB 3	(08/03/2015)
(Signature Place Apartments)		
Silverstone Apartment Homes, LLC	WR-1355, SUB 2	(02/09/2015)
(Silverstone Apartments)		
Sumare Limited Partnership		
(Sumter Square Apartments)	WR-1163, SUB 6	(07/29/2015)
(Sumter Square Apartments)	WR-1163, SUB 7	(09/28/2015)
TBR Lake Boone Owner, LLC	WR-1374, SUB 3	(07/30/2015)
(The Villages of Lake Boone Trail Apts.)		
Trinity Properties, LLC		
(Poplar West Apartments)	WR-1696, SUB 5	(09/15/2015)
(Governor Apartments)	WR-1696, SUB 6	(09/15/2015)
(Georgetown Apartments)	WR-1696, SUB 7	(09/15/2015)
(Campus Walk Apartments)	WR-1696, SUB 8	(09/15/2015)
West Montecito Company, L. P.	WR-1164, SUB 5	(07/29/2015)
(Montecito West Apartments)		

Penrith Townhomes, LLC -- WR-1763, SUB 2; Errata Order *(Woodland Creek Apartments)* (08/25/2015)

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