BIENNIAL REPORT OF THE NORTH CAROLINA UTILITIES COMMISSION

TO

THE GOVERNOR OF NORTH CAROLINA, THE ENVIRONMENTAL REVIEW COMMISSION, AND THE JOINT LEGISLATIVE COMMISSION ON GOVERNMENTAL OPERATIONS

REGARDING

THE RESULTS OF COST ALLOCATIONS FOR ELECTRIC UTILITIES INVOLVING:

1. **RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARDS COSTS**

2. **DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY PROGRAMS COSTS AND**

3. **CERTAIN FUEL AND FUEL-RELATED COSTS**

(Pursuant to Section 14 of Session Law 2007-397)

Date Due: October 1, 2011
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EXECUTIVE SUMMARY

The Utilities Commission is providing this report to the Governor, the Environmental Review Commission, and the Joint Legislative Commission on Governmental Operations pursuant to Section 14 of Session Law 2007-397. Section 14 requires the Commission to submit a report on the actual results of the cost allocations established by the Commission pursuant to G.S. 62-133.8(h), G.S. 62-133.9(e) and (f), and G.S. 62-133.2(a2) and (a3) in proceedings conducted and decided during the preceding two fiscal years ending June 30, 2011.

Section 2.(a) of Session Law 2007-397, G.S. 62-133.8, establishes a renewable energy and energy efficiency portfolio standard (REPS) for North Carolina's electric power suppliers. Subsection (h) of G.S. 62-133.8 provides for the recovery of certain costs incurred by an electric power supplier to comply with the REPS requirements through an annual rider allocated among residential, commercial, and industrial customers. Session Law 2007-397 also requires electric suppliers to implement demand-side management (DSM) and energy efficiency (EE) measures. Subsection (d) of G.S. 62-133.9 provides for the recovery of costs incurred by electric public utilities for adoption and implementation of new DSM and EE measures through a rider approved by the Commission. In determining the amount of the DSM and EE rider, the Commission is required to assign or allocate costs as set forth in G.S. 62-133.9(e) and (f). Lastly, Section 5 of Session Law 2007-397 amended G.S. 62-133.2. Among other changes, subsections (a2) and (a3) were added to G.S. 62-133.2 and require the Commission to allocate certain fuel and fuel-related costs as specified in those subsections to be recovered as separate components of the rider for fuel and fuel-related costs.

This report is divided into three parts describing the cost allocations established by the Commission in conformity with the statutes cited above.

Duke Energy Carolinas, LLC (Duke), and Progress Energy Carolinas, Inc. (Progress), each have multiple proceedings described in this report, as follows:

	REPS Rider	**DSM/EE Rider**	**Fuel Rider**
Duke	2	2	2
Progress	2	3	2

All of the cost allocations in their proceedings are consistent with State Statutes and Commission Rules.

Reference is made in this report to various Commission dockets. To review the entire official record in any docket, persons may visit the web site of the Utilities Commission (http://www.ncuc.net), select "Dockets" from the homepage, select "Docket Search" and then enter the docket number.

PART 1: Cost Allocations Established Pursuant to G.S. 62-133.8(h)

The first part of this report provides the actual results of the cost allocations established by the Commission pursuant to G.S. 62-133.8(h) as enacted by Section 2 of Session Law 2007-397 (Senate Bill 3) during the two fiscal years ending June 30, 2011. G.S. 62-133.8 is the statute that establishes a renewable energy and energy efficiency portfolio standard (REPS) for North Carolina electric power suppliers. Electric power suppliers include public utilities, electric membership corporations and municipalities that sell electric power to retail electric power customers in North Carolina.

G.S. 62-133.8(h)(4) allows electric power suppliers to recover the incremental costs that they incur to comply with REPS (and costs of related research) from their customers via an annual rider, with those charges not to exceed the following per-account annual charges:

Customer Class	2008-2011	2012-2014	2015 and thereafter
Residential	$ 10.00	$ 12.00	$ 34.00
Commercial	$ 50.00	$ 150.00	$ 150.00
Industrial	$500.00	$1,000.00	$1,000.00

G.S. 62-133.8(h)(5) states that the Commission shall adopt rules establishing a procedure for the annual assessment of the per-account charges to customers to allow each electric public utility the timely recovery of all reasonable and prudent costs of REPS compliance and related research.[1] The statute further requires that costs recovered from individual customers on a per-account basis must be assessed in the same proportion as the per-account maximum annual charges for each customer class listed above.

On February 29, 2008, the Commission issued an Order in Docket No. E-100, Sub 113, establishing rules pursuant to Senate Bill 3. Those rules include Rule R8-67, which requires electric power suppliers to annually file a prospective REPS compliance plan and a historic REPS compliance report. Electric public utilities that seek REPS cost recovery via an annual rider must also file a REPS rider application coincident with their annual fuel rider application. (See Part 3 of this report for more information about the cost allocations established in annual fuel proceedings.)

Rule R8-67(c)(4) requires each electric power supplier to propose a method for determining its cap on incremental REPS costs for REPS compliance and research, including a method for determining its year-end number of customer accounts subject to the cost caps. The phrase "year-end number of customer accounts" means

> The number of accounts within each customer class as of December 31 for a given calendar year and, unless approved otherwise by the Commission pursuant to subsection (c)(4), determined in the same manner as that information is reported to the Energy Information

[1] Research costs recovered via the annual REPS rider cannot exceed $1 million per year. Qualifying research costs are those that encourage the development of renewable energy, energy efficiency, or improved air quality. G.S. 62-133.8(h)(1)(b).

Administration (EIA), United States Department of Energy, for annual electric sales and revenues reporting.

The term "incremental costs," as defined in G.S. 62-133.8(h)(1), includes the costs of renewable energy purchases "that are in excess of the electric power supplier's avoided costs." The term "avoided costs" includes both avoided energy costs and avoided capacity costs.

Any under-collection of such costs through the rider is to be collected prospectively. Any over-collection of such costs through the rider is to be refunded to customers, with interest. Under- and over-collections are reflected in a REPS experience modification factor (EMF) rider.

Duke Energy Carolinas, LLC (Duke) – Docket No. E-7, Sub 872

Duke filed its initial REPS rider application on March 4, 2009, for charges effective September 1, 2009, through August 31, 2010. Duke sought recovery of $4,200,871 of REPS compliance and research costs. The Commission held an evidentiary hearing on June 9, 2009. At issue was Duke's definition of "customer account." This issue affected both the amount of REPS charges to be allocated to each customer class as well as Duke's maximum REPS spending.

Commission Rule R8-67(a)(4) provides that electric suppliers shall determine the number of customer accounts for purposes of the REPS requirements in the same manner as that information is reported to the United States Department of Energy, Energy Information Administration (EIA) for annual electric sales and revenues reporting. Further, the rule provides that the Commission may approve a modification of this method where appropriate. Rule R8-67(c)(4) provides that the method for determining the electric supplier's cap on incremental REPS costs may be specific to each supplier and shall be based upon a fair and reasonable allocation of costs.

Duke reports its number of customers to EIA by counting each agreement (one meter at one voltage at one delivery point) as one customer, but excluding any duplicate accounts for special services, as directed by the EIA. These special services include things such as outdoor lighting. Duke proposed to use that same method in determining the number of customer accounts for REPS purposes, but, in addition, Duke proposed that the lower residential REPS charge be applied to certain general service accounts. The general service accounts in question have low use and/or they may be auxiliary services to another rate schedule, for example, a well pump, sign, or fire pump. Duke proposed this method in order to minimize the impact of REPS charges on small customers, especially when a non-demand metered service account is associated with the customer's primary account. Duke sought to avoid inequities for certain customers, such as a residential customer that has a garage that is separately metered from the house and is on a general service rate. In such a scenario, the customer would pay the residential REPS charge for the service to the house, and the commercial REPS charge for the service to the garage. Duke's proposal would reduce Duke's ceiling on incremental REPS costs by about $6,650,000 per year.

The Public Staff and the North Carolina Sustainable Energy Association opposed Duke's proposal to reclassify small-usage commercial and industrial accounts as being residential. The Public Staff instead supported a method to eliminate the REPS charges for all accounts that are associated with another customer account at the same location. The Commission agreed that it is improper to treat a commercial or industrial customer as residential simply because of its low usage, because it is served by a particular rate schedule, or because it does not have a demand meter. The Commission also expressed concern that REPS costs that are shifted away from certain customers would be shifted onto Duke's remaining customers. The Commission disapproved Duke's proposal to charge certain low usage accounts at the residential REPS rate and ordered the Company to instead broaden its use of the EIA exception to encompass all auxiliary accounts that are located on the same premises as a main account. Therefore, the Commission ordered Duke to file revised calculations of its REPS and REPS EMF riders based on a revised estimate of the number of customer accounts. In its Order issued on August 21, 2009, the Commission approved Duke's cost-recovery request but required Duke to use a different approach to define "customer account," and then revise its proposed customer charges to be consistent with that approach. The Order also stated that the new charges would begin at the same time as Duke's new base rates, which were under consideration in a separate docket (Docket No. E-7, Sub 909), and end August 31, 2010.

On September 24, 2009, Duke filed it REPS rider compliance filing and proposed to exclude from the rider all services defined as auxiliary to another agreement. The Company proposed to define an auxiliary service as a non-demand metered, nonresidential service provided under Schedule SGS, at the same premises and with the same address and account name as another account for which a monthly REPS charge is applied. Under this approach, the number of customer accounts and the monthly REPS charges that would be applied to them were as follows:

Customer Type	Number of Customer Accounts	Monthly REPS Charge*	Monthly REPS EMF Charge*	Total Monthly REPS Rider **	Total Annual REPS Charge**
Residential	1,713,885	$0.11	$0.05	$0.16	$ 1.92
Commercial	232,531	$0.56	$0.27	$0.86	$ 10.32
Industrial	5,863	$5.57	$2.71	$8.56	$102.72

*Excludes gross receipts tax and regulatory fee.
**Includes gross receipts tax and regulatory fee.

These costs are allocated across customer classes in the same proportion as the per-account annual cost caps established by G.S. 62-133.8(h)(4), and are below those maximum annual charges. (See page 2 for the cost caps.)

By Order dated December 15, 2009, the Commission approved Duke's REPS rider as stated above, for an 8-month period beginning January 1, 2010, and ending August 31, 2010.

Duke Energy Carolinas, LLC, (Duke) – Docket No. E7- Sub 936

On March 2, 2010, Duke filed its second annual REPS rider application in which it sought recovery of $9,379,008 in incremental REPS expenses. Duke had agreed to provide REPS compliance services, including the procurement of renewable energy certificates (RECs), to the following wholesale entities (which are also electric power suppliers subject to REPS requirements): Rutherford Electric Membership Corporation, the City of Dallas, Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain. In order to properly allocate incremental REPS costs between Duke and these wholesale Duke customers, Duke used a combined aggregate cost cap methodology. The combined total numbers of accounts at year end, by customer class, for both Duke's North Carolina retail accounts and the wholesale customers' North Carolina retail accounts were multiplied by the statutory maximum per account annual REPS charges to determine combined total cost cap amounts by customer class and in total. In the case where a wholesale customer chose to self-supply a portion of its REPS requirement (for example, by using its SEPA allocation to partially meet the requirement as provided in G.S. 62-133.8(c)), the combined total number of customer accounts on which the cost allocation was based was adjusted on a pro rata basis to recognize that a portion of the compliance requirement will not be supplied by Duke. This method of allocation results in the same cost per customer account for both Duke and the wholesale entities.

By Order dated August 13, 2010, the Commission approved Duke's REPS rider charges, as shown below, for a 12-month period beginning September 1, 2010, and ending August 31, 2011:

Customer Type	Monthly REPS Charge*	Monthly REPS EMF Charge*	Total Monthly REPS Rider **	Total Annual REPS Charges**
Residential	$0.17	$0.09	$ 0.27	$ 3.24
Commercial	$0.83	$0.45	$ 1.32	$ 15.84
Industrial	$8.32	$4.45	$13.21	$158.52

*Excludes gross receipts tax and regulatory fee.
**Includes gross receipts tax and regulatory fee.

These costs are allocated across customer classes in the same proportion as the per-account annual cost caps established by G.S. 62-133.8(h)(4), and are below those maximum annual charges. (See page 2 for the cost caps.)

Progress Energy Carolinas, Inc. (PEC) – Docket No. E-2, Sub 948

On May 18, 2009, PEC filed its second annual REPS rider application in which it requested recovery of $15,569,451 in incremental REPS costs and related research. Since PEC had agreed to provide REPS compliance services beginning December 1, 2009, including the procurement of renewable energy certificates (RECs), to certain of its wholesale customers (which are also electric power suppliers subject to REPS requirements), it was necessary to allocate PEC's REPS costs between its own retail customers and the customers of the wholesale entities. PEC proposed to make this allocation on the basis of the relative energy use of its customers versus those of the wholesale entities during the forecast period (the 12 months ending November 30, 2010). This approach resulted in 0.47% of the forecast period REPS costs being allocated to the wholesale entities. The Commission found this method of allocation to be appropriate in the Order it issued on November 12, 2009, approving PEC's REPS rider. The monthly REPS riders approved by the Commission for the 12 months ending November 30, 2010, are as follows:

Customer Class	REPS Rider Charge Per Month*	REPS EMF Rider Charger Per Month*	Total Monthly REPS Charge**	REPS Rider Charge Per Year**
Residential	$ 0.56	$0.07	$ 0.65	$ 7.80
Commercial	$ 2.78	$0.33	$ 3.22	$ 38.64
Industrial	$27.82	$3.31	$32.20	$386.40

*Excludes gross receipts tax and regulatory fee.
**Includes gross receipts tax and regulatory fee.

These costs are allocated across customer classes in the same proportion as the per-account annual cost caps established by G.S. 62-133.8(h)(4), and are below those maximum annual charges. (See page 2 for the cost caps.)

<u>Progress Energy Carolinas, Inc. (PEC) – Docket No. E-2, Sub 974</u>

On May 18, 2010, PEC made its third annual REPS rider application in which it sought to recover $14,287,984 of incremental REPS and related research costs. As in PEC's previous REPS rider proceeding, it was necessary to allocate those costs between PEC's own retail customers and the customers of the wholesale entities for which PEC is providing REPS compliance services. PEC again made the allocation on an energy basis, and the Commission found this approach to be appropriate. Because the Company had over-recovered its REPS costs under the rider established the previous year by $173,344, the Company was required to refund this amount, with interest, via the REPS EMF rider. By Order dated November 17, 2010, the Commission approved PEC's REPS rider charges for the 12 months ending November 30, 2011, as follows:

Customer Class	REPS Rider Charge Per Month*	REPS EMF Rider Charger Per Month*	Total Monthly REPS Charge**	REPS Rider Charge Per Year**
Residential	$ 0.57	($0.01)	$ 0.58	$ 6.96
Commercial	$ 2.84	($0.04)	$ 2.90	$ 34.80
Industrial	$28.35	($0.39)	$28.93	$347.16

*Excludes gross receipts tax and regulatory fee.
**Includes gross receipts tax and regulatory fee.

These costs are allocated across customer classes in the same proportion as the per-account annual cost caps established by G.S. 62-133.8(h)(4), and are below those maximum annual charges. (See page 2 for the cost caps.)

PART 2: Cost Allocations Established Pursuant to G.S. 62-133.9(e) and (f)

The second part of this report provides the actual results of the cost allocations established by the Commission pursuant to G.S. 62-133.9(e) and (f), as enacted by Section 4(a) of Session Law 2007-397 (Senate Bill 3), regarding cost recovery for demand-side management (DSM) and energy efficiency (EE) measures.

Subsection (e) of G.S. 62-133.9 provides that the Commission shall determine the appropriate assignment of costs of new DSM and EE measures for electric public utilities and shall assign the costs of the programs only to the class or classes of customers that directly benefit from such programs.

Subsection (f) of G.S. 62-133.9 provides that none of the costs of new DSM or EE measures of an electric power supplier shall be assigned to any industrial customer that notifies the industrial customer's electric power supplier that, at the industrial customer's own expense, the industrial customer has implemented at any time in the past or, in accordance with stated, quantified goals for DSM and EE, will implement alternative DSM and EE measures and that the industrial customer elects not to participate in DSM or EE measures under G.S. 62-133.9.

Further, the opt-out provision of subsection (f) of G.S. 62-133.9 also applies, pursuant to Commission Rule R8-69(a)(3), to any commercial customer that has an annual energy usage of not less than 1,000,000 kilowatt-hours (kWh), measured in the same manner as the electric public utility that serves the commercial customer measures energy for billing purposes.

Any under-collection of such costs through the rider is to be collected prospectively. Any over-collection of such costs through the rider is to be refunded to customers, with interest.

The following sections of this report provide the actual results of the cost allocations established by the Commission pursuant to G.S. 62-133.9 (e) and (f) in proceedings conducted and decided during the previous two fiscal years ending June 30, 2011.

Duke Energy Carolinas, LLC (Duke) – Docket No. E-7, Sub 831

On May 7, 2007, in Docket No. E-7, Sub 831, Duke filed a petition for approval of a new save-a-watt approach to energy efficiency (EE) programs; a portfolio of EE programs; and an EE rider (Rider EE) to compensate and reward it for verified energy efficiency results and to recover the amortization of, and a return on, 90% of the costs avoided by the save-a-watt approach. Session Law 2007-397 includes provisions bearing on the Commission's authority to consider and authorize proposals such as the save-a-watt approach. Consequently, the Commission determined that, after completion of the rulemaking proceeding to implement Senate Bill 3, the Commission would schedule a hearing to consider the merits of Duke's save-a-watt petition. Beginning

July 28, 2008, the Commission conducted evidentiary hearings regarding Duke's petition.

On February 26, 2009, the Commission approved Duke's request to put its proposed rider into effect, subject to refund with interest, pending final resolution of the Sub 831 proceeding. In addition, the Commission required Duke to file supplemental information by March 31, 2009, regarding the profitability of the save-a-watt program. On May 1, 2009, Duke filed a letter and proposed Notice to Customers and stated that because of a pending motion for reconsideration,[2] it had elected to put into effect, subject to refund, only its conservation programs. On June 1, 2009, Duke implemented its interim DSM/EE rider.[3]

On June 12, 2009, Duke, the Public Staff, and a group of Environmental Intervenors[4] filed an Agreement and Joint Stipulation of Settlement (Settlement) that would compensate Duke for successful DSM and EE programs based on a discount to the avoided costs of a power plant, rather than based on Duke's actual program costs. However, the Settlement modified Duke's original proposal. The Settlement proposed a four-year limited term pilot and included the separate recovery of net lost revenues for a limited time period. In addition, the Settlement provided a series of annual true-ups to update Duke's revenue requirements (and rider charges) based on actual customer program participation. The final avoided cost related revenue requirements over the four-year period would be based on Duke's measured and verified savings achieved, subject to an earnings cap, with earnings measured as the excess of revenue requirements over DSM or EE program costs.

Under the "modified save-a-watt approach" set forth in the Settlement, Duke would be compensated on 75% of avoided capacity costs for DSM programs and 50% of the net present value (NPV) of the avoided energy costs plus 50% of the NPV of avoided capacity costs for EE programs. In addition, the Settlement contained a "pay for performance" feature in which Duke's compensation would depend upon actual DSM and EE savings achieved and verified by an independent third party. Duke would remain at risk, based upon its actual performance, for recovery of its DSM and EE costs, as well as any management incentive. The Settlement included performance targets such that Duke would receive a higher level of incentive based on how well it achieves DSM and EE savings that result in bill savings for customers. Duke increased the amount of EE avoided cost savings it would target to achieve. The Company's revenues recovered on the basis of percentages of avoided costs would be limited to

[2] Air Products and Chemicals, Inc., an intervenor in the Sub 831 proceeding, filed a Petition to Reconsider on March 20, 2009, which was denied.

[3] Such rates were provided in the Biennial Report of the North Carolina Utilities Commission to the Governor of North Carolina and the Joint Legislative Commission on Governmental Operations Regarding Proceedings for Electric Power Suppliers Involving Energy Efficiency and Demand-Side Management Programs, Cost-Recovery and Incentives (September 1, 2011 DSM/EE Program Report) [Pursuant to G.S. 62-133.9(i)].

[4] The Environmental Intervenors included the Southern Alliance for Clean Energy, the Environmental Defense Fund, the Natural Resources Defense Council, and the Southern Environmental Law Center.

the amount needed to produce an after-tax return on program costs between 5% and 15%, depending on Duke's success in reaching a targeted aggregate EE and DSM avoided cost savings level. In addition, the amount of net lost revenues Duke would be allowed to recover is limited to those incurred within 36 months of implementation of a particular measure, and recovery of net lost revenues is separate, and, hence, more transparent than it was under Duke's initial proposal. The Settlement stated that the modified save-a-watt approach shielded ratepayers from the risk of tying rates to unknown and variable supply-side avoided costs by locking in the avoided costs (with certain exceptions).

On February 9, 2010, the Commission issued an Order Approving Agreement and Joint Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues. The Commission concluded that the level of avoided cost recovery proposed in the Settlement was reasonable and in the public interest, and also approved the separate recovery of net lost revenues from Duke's implementation of EE, but not DSM, measures[5] as contemplated by the Stipulating Parties. In addition, the Commission made several modifications to the net lost revenues provision of the Settlement.[6]

With respect to the issue of cost allocations to various classes of customers, in its February 9, 2010 Order, the Commission concluded: (1) that the costs of Duke's DSM and EE programs should be allocated to the North Carolina and South Carolina retail jurisdictions; (2) that such costs should be recovered from only the class or classes of retail customers to which the programs are targeted; and (3) that no costs should be allocated to the wholesale jurisdiction.

The revenue requirements related to EE programs and net lost revenues are assigned to the North Carolina and South Carolina retail jurisdictions based on kWh sales to system retail customers from Duke's cost of service study. For Year 1, based upon Duke's cost of service study, the ratio of North Carolina retail kWh sales to total retail kWh sales was 72.2%.

For DSM programs, the revenue requirements are allocated between the North Carolina and South Carolina retail jurisdictions based on contributions to system peak retail demand by all system retail customers based on the cost of service study. For Year 1, based upon Duke's cost of service study, the ratio of North Carolina retail contribution to retail system peak demand was 74.0%.

The following chart sets forth the total avoided cost revenue requirements and net lost revenue revenue requirements approved by the Commission in its December 14, 2009 Notice of Decision for each class of customers with respect to

[5] The Settlement erroneously did not reflect the parties' intent that recovery of net lost revenues was limited to those resulting from EE programs only. The Commission's February 9, 2010 Order corrected this error and expressly limited the recovery of net lost revenues to those associated with EE programs.

[6] For more information, see Docket No. E-7, Sub 831.

Duke's approved DSM and EE programs included in the Sub 831 proceeding (including gross receipts taxes and regulatory fee):

	Year 1
Residential Avoided Cost Revenue Requirement	$18,394,873
Residential Net Lost Revenue Revenue Requirement	6,628,794
Total Residential Revenue Requirement	$25,023,667
Non-Residential Avoided Cost Revenue Requirement	12,983,102
Non-Residential Net Lost Revenue Revenue Requirement	1,082,481
Total Non-Residential Revenue Requirement	$14,065,583
Total Revenue Requirement[7]	$39,089,250

The total residential revenue requirement of $25,023,667 divided by the projected North Carolina only retail residential sales of 20,745,460,539 kWh produced a customer rider amount of 0.1206¢ per kWh. The total non-residential revenue requirement of $14,065,583 divided by the projected North Carolina only retail non-residential sales of 32,830,015,696 kWh produced a customer rider amount of 0.0428¢ per kWh.

Duke Energy Carolinas, LLC (Duke) – Docket No. E-7, Sub 941

On March 5, 2010, Duke filed its second annual application for approval of its DSM/EE cost recovery rider (Rider 2) seeking to recover approximately $54 million in DSM/EE revenues relative to its approved DSM and EE programs. The period during which the DSM/EE rider established in this proceeding will be in effect is the 12-month period January 1, 2011, through December 31, 2011.

Rider 2 is designed to allow Duke to collect a level of revenue equal to 75% of its estimated avoided capacity costs applicable to DSM programs and 50% of the net present value of estimated avoided capacity and energy costs applicable to EE programs, and to recover net lost revenues for EE programs only. Revenues collected under Rider 2 are based on the expected avoided costs (and the associated net lost revenues) to be realized at an 85% level of achievement of the Company's avoided cost savings target for Vintage 2 measures per the Settlement.

Revenue requirements for Duke's DSM and EE programs are recovered only from the class or classes of retail customers to which the programs are targeted. The revenue requirements 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 to total retail kWh sales, and then recovered only from North Carolina residential customers. The revenue requirements for EE programs targeted at non-residential customers across North Carolina and South Carolina are allocated to the North Carolina jurisdiction based on the ratio of North Carolina retail kWh sales to total retail kWh sales, and then recovered from only North Carolina retail non-residential customers. For Rider 2, based upon Duke's 2008 cost of

[7] Revenue requirements are based upon 85% achievement.

service study, the ratio of North Carolina retail kWh sales to total retail kWh sales was 72.1735%.

For DSM programs, because residential and non-residential programs are similar in nature, the revenue requirement for all retail DSM programs targeted at both residential and non-residential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on North Carolina retail customers' contribution to retail system peak demand. For Rider 2, based upon Duke's 2008 cost of service study, the ratio of North Carolina retail contribution to total retail system peak demand was 74.0349%. The North Carolina retail revenue requirements are then allocated between residential and non-residential customers based upon each group's contribution to the North Carolina retail peak demand. For Rider 2, the allocation between residential and non-residential was 42.37% and 57.63%, respectively. Consistent with the Settlement and the Commission's February 9, 2010 Order, no costs are allocated to the wholesale jurisdiction.

On August 3, 2010, the Commission issued an Order authorizing Duke to recover the following amounts related to Rider 2 (including gross receipts taxes):

	Year 2
Residential Avoided Cost Revenue Requirement	$22,376,906
Residential Net Lost Revenue Revenue Requirement	13,001,916
Total Residential Revenue Requirement	$35,378,822
Non-Residential Avoided Cost Revenue Requirement	16,851,767
Non-Residential Net Lost Revenue Revenue Requirement	2,080,893
Total Non-Residential Revenue Requirement	$18,932,660
Total Revenue Requirement	$54,311,482

The total residential revenue requirement of $35,378,822 divided by the projected North Carolina only retail residential sales of 20,783,231,039 kWh produced a customer rider amount of 0.1702¢ per kWh. The total non-residential revenue requirement of $18,932,660 divided by the projected North Carolina only retail non-residential sales of 32,373,648,374 kWh produced a customer rider amount of 0.0585¢ per kWh, which was divided among three categories of non-residential customers as a result of Duke's request for flexibility to manage its large customer "opt outs."[8]

[8] Such rates were provided in the Biennial Report of the North Carolina Utilities Commission to the Governor of North Carolina and the Joint Legislative Commission on Governmental Operations Regarding Proceedings for Electric Power Suppliers Involving Energy Efficiency and Demand-Side Management Programs, Cost-Recovery and Incentives (September 1, 2011 DSM/EE Program Report) [Pursuant to G.S. 62-133.9(i)].

Progress Energy Carolinas, Inc. (Progress or PEC) – Docket No. E-2, Sub 931

PEC filed its first request under G.S. 62-133.9 for approval of an annual DSM/EE cost recovery rider for costs and utility incentives relative to six DSM and EE programs[9] on June 6, 2008, in Docket No. E-2, Sub 931. The DSM/EE rider established in this proceeding was in effect for the 12-month period December 1, 2008, through November 30, 2009.

On November 14, 2008, the Commission approved PEC's request to put its proposed rider into effect on December 1, 2008, subject to refund with interest, pending final resolution of this proceeding.[10] PEC requested that its interim rider remain in effect until December 1, 2009.

The Commission held evidentiary hearings on January 7 and 8, 2009, and on June 15, 2009, the Commission issued its Order in this proceeding. The Order decided, among other things, an unresolved issue among the stipulating parties[11] related to allocating DSM and EE costs among customer classes. The Commission concluded that G.S. 62-133.9(e) provides that the costs of new DSM/EE programs are to be assigned and recovered from only the class or classes of customers that directly benefit from such programs. Therefore, the costs of an approved DSM/EE program or measure should first be allocated to the North and South Carolina retail jurisdictions and such costs should then be recovered from only the class or classes of North Carolina retail customers to which the program is targeted. Consistent with Paragraph 4.A. of the Stipulation, which was approved by the Commission by Order issued June 15, 2009, costs of an approved DSM/EE program or measure are not allocated to the wholesale jurisdiction.

With respect to PEC's Distribution System Demand Response (DSDR) program,[12] the Commission concluded that the costs of this program should be recovered from all retail customers that benefit; that is, all retail customers that receive power via PEC's distribution system. Consequently, industrial and large commercial customers that receive power via PEC's distribution system benefit from DSDR and may not opt out of the cost recovery rider for this program. Further, the Commission concluded that the DSDR program should be classified as an EE program rather than as a DSM program as proposed by PEC in its application.

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[9] See Docket No. E-2, Subs 908, 926, 927, and 928 and the September 1, 2009 DSM/EE Program Report for detailed information regarding each specific program.

[10] Such rates were provided in the September 1, 2009 DSM/EE Program Report.

[11] On December 9, 2008, PEC, the Public Staff, and Wal-Mart filed an Agreement and Stipulation of Partial Settlement (Stipulation) that addressed most, but not all, of the issues among these three parties relative to the Sub 931 DSM/EE rider.

[12] PEC's DSDR program was approved on June 15, 2009, in Docket No. E-2, Sub 926.

As explained above, G.S. 62-133.9(f) provides that industrial customers and certain large commercial customers may opt-out of the cost recovery rider for new DSM or EE programs under certain circumstances, in which case none of the costs of the programs will be assigned to those customers.[13] In its June 15, 2009 Order, the Commission stated that, according to the statute, the notice for such an opt-out requires two statements: (1) that the customer has, or will, implement alternative DSM and EE measures at the customer's own expense, and (2) that the customer elects not to participate in the program to which it opts out. The Commission further stated that it appears from the language of G.S. 62-133.9(f) that certain industrial and large commercial customers were given the ability to opt-out because they had implemented or will implement, their own DSM or EE measures and should not essentially "pay twice" for such benefits. With regard to PEC's DSDR program, the Commission concluded that the DSDR program achieves a type of efficiency, voltage reduction, that no customer could achieve on its own initiative; therefore, the rationale that an industrial or large commercial customer should be allowed to opt-out so as not to "pay twice" for efficiency does not logically apply to the DSDR program. Further, the DSDR program involves activities and equipment on the electric supplier's side of the meter, and these activities and equipment benefit all customers who take service from the distribution system. Consequently, the Commission concluded that no customer served by PEC's distribution grid can elect to "not participate" in DSDR.

In regard to the opt-out eligibility requirement and the definition of "large commercial customer" contained in Commission Rule R8-69, the Commission concluded in its June 15, 2009 Order that it was appropriate to refine, as proposed by the stipulating parties, the definition to include the following language:

> 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. . . .

In its June 15, 2009 Order, the Commission also determined that it was appropriate for PEC to recover costs for the six DSM and EE programs in its DSM/EE rider subject to review and true-up during its next annual rider proceeding. Specifically, the Commission concluded that PEC's North Carolina retail capitalized operation and maintenance expenses for its DSM/EE programs for purposes of determining an annual rider in this proceeding were $27,980,374.[14] Further, the Commission required PEC to file revised exhibits to reflect the Commission's decisions regarding the appropriate costs to recover, cost allocations, and DSM/EE rates per customer class.

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[13] In this proceeding, opt-out sales represent 39.6% of total North Carolina rate class sales (MWh). As a result of the opt-out provision, the remaining customers would be assigned such costs as required by statute.

[14] Such amounts include reasonable and appropriate estimates of North Carolina retail capitalized O&M expenses which are subject to review in PEC's next DSM/EE rider proceeding (Docket No. E-2, Sub 951).

Motions for reconsideration regarding the DSDR program were filed; the Commission requested comments and reply comments from the parties regarding such motions; and on September 16, 2009, oral arguments were heard before the Commission. On November 25, 2009, the Commission issued Orders: (1) deciding issues relative to the reconsideration requests, and (2) requiring PEC to again recalculate its proposed rider based on those decisions. The Commission determined, on reconsideration, that industrial and large commercial customers that opt out of PEC's EE and DSM programs will not be charged, via a rider, for the DSDR program.[15]

On January 4, 2010, and March 8, 2010, PEC filed revised and proposed, respectively, DSM/EE compliance rates in Docket No. E-2, Subs 931 and 951. In its March 8, 2010 filing, PEC's revised proposed compliance rates were structured such that the adjustments to the DSM/EE rates previously approved on an interim basis were incorporated into the DSM/EE EMF rider now proposed for implementation effective for the period April 1, 2010, through November 30, 2010. On March 19, 2010, the Commission issued an Order approving PEC's proposed compliance rates.

The cost allocations established by the Commission in its March 19, 2010 Order are set forth below in the Docket No. E-2, Sub 951 discussion.

Progress Energy Carolinas, Inc. (Progress or PEC) – Docket No. E-2, Sub 951

On June 4, 2009, in Docket No. E-2, Sub 951, PEC filed its second annual DSM/EE rider application seeking to recover $24.2 million in DSM/EE program costs, incentives, and carrying costs relative to nine DSM and EE programs. The Commission held an evidentiary hearing on September 16, 2009, and on November 25, 2009, the Commission issued an Order concerning PEC's DSM/EE rider request. On January 4, 2010 and March 8, 2010, PEC filed proposed DSM/EE compliance rates in Docket No. E-2, Subs 931 and 951. On March 19, 2010, the Commission issued an Order approving PEC's revised proposed compliance rates, which established the DSM/EE rider effective for the period April 1, 2010, through November 30, 2010.

To calculate the DSM rider component applicable to the rate period, PEC first allocated total company, or system, DSM costs and incentives to the North Carolina retail jurisdiction using an allocation factor of 85.9% based upon the ratio of the North Carolina retail demand to the PEC system retail demand at the hour of the annual summer peak. The allocation percentage is updated each May, and is based on the prior year's peak demand.

To calculate the EE rider component applicable to the rate period, PEC first allocated total company, or system, EE costs and incentives to the North Carolina retail jurisdiction using an allocation factor of 85.4% based upon the ratio of North Carolina retail sales to PEC system retail sales at the point of generation. The allocation percentage is updated each May and is based on the prior calendar year retail sales.

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[15] For more information, see the Commission's November 25, 2009 Order in Docket E-2, Subs 926 and 931.

North Carolina retail costs are then assigned to customer classes based on program design and participation, that is, costs are assigned to customer groups that directly benefit from the programs. Residential program costs are allocated solely to residential customers, general service program costs are allocated solely to general service customers, and lighting program costs are allocated solely to lighting customers. When a DSM or EE program benefits multiple classes of customers, EE costs are multiplied by rate class energy allocation factors and DSM costs are multiplied by rate class demand allocation factors for purposes of cost assignment.

The rate class allocation factors were developed assuming that customers electing to opt out of the DSM/EE rider will continue to do so. Since usage for opt-out customers was not forecasted, the energy allocation rate class factors were developed from the forecasted rate class usage, after subtracting actual sales for opt-out customers for the year ended March 31, 2009.[16] The energy allocation factors applicable to the residential, general service, and lighting classes based upon the forecast of rate class sales for the recovery period of April 1, 2010, through November 30, 2010, were 53.51%, 44.95%, and 1.54%, respectively. The demand allocation rate factors are based on the summer coincident peak demand for 2008, after subtracting actual demand for opt-out customers for the year ended March 31, 2009. PEC's forecast did not provide rate class coincident peak demands; therefore, the most recent historical data was deemed to be representative of future demand impacts. The demand allocation rate factors applicable to the residential, general service, and lighting classes for the recovery period of April 1, 2010, through November 30, 2010, were 60.10%, 39.90%, and 0.00%, respectively. For the recovery period April 1, 2010, through November 30, 2010, the Company's DSDR program, an EE program, was the only program of the nine DSM and EE programs that benefitted multiple customer classes. Rate class energy allocation factors were employed to allocate costs related to PEC's DSDR program.

The calculated rate class DSM and EE revenue requirements are divided by rate class sales, after adjustment for opt-out customers, to establish the rate class DSM/EE rate. The following charts set forth the total costs and utility incentives, expressed in terms of revenue requirements, and the corresponding rate class DSM/EE rate to be collected from each class of customers as approved by the Commission in its March 19, 2010 Order with respect to the nine DSM and EE programs included in the Sub 951 proceeding (excluding gross receipts taxes and regulatory fee):

NC Rate Class	Adjusted NC Rate Class kWh Sales	Total Revenue Requirements	Total EE Rate
Residential	15,309,108,408	$9,151,581	$0.000598
General Service	12,860,149,193	8,090,988	0.000629
Lighting	439,535,618	212,341	0.000483
Total NC Retail	28,608,793,219	$17,454,910	

[16] Actual opt-out sales for the 12-months ending March 31, 2009 were 10,165,706,612 kWhs.

NC Rate Class	Adjusted NC Rate Class kWh Sales	Total Revenue Requirements	Total DSM Rate
Residential	15,309,108,408	$2,453,613	$0.000160
General Service	12,860,149,193	669,893	0.000052
Lighting	439,535,618	0	0.000000
NC Retail	28,608,793,219	$3,123,506	

NC Rate Class	Adjusted NC Rate Class kWh Sales	Adjusted EE EMF Revenue Requirement	Total EE EMF Rate
Residential	15,309,108,408	($2,299,372)	($0.000150)
General Service	12,860,149,193	(888,864)	(0.000069)
Lighting	439,535,618	92,831	0.000211
NC Retail	28,608,793,219	($3,095,405)	

NC Rate Class	Adjusted NC Rate Class kWh Sales	Adjusted DSM Revenue EMF Requirement	Total DSM EMF Rate
Residential	15,309,108,408	($2,542,855)	($0.000166)
General Service	12,860,149,193	(298,907)	(0.000023)
Lighting	439,535,618	0	0.000000
NC Retail	28,608,793,219	($2,841,762)	

Based upon the information set forth above, DSM/EE rider charges were set as follows, effective April 1, 2010, including adjustments for over/under collections from December 2008 through November 2009, uncollectibles, residential energy conservation discount, gross receipts taxes, and regulatory fee, which are not reflected in the rates set forth above:

Rate Class	DSM/EE Rate (¢/kWh)	DSM/EE EMF (¢/kWh)	DSM/EE Annual Rider (¢/kWh)
Residential	0.00080	(0.00038)	0.042
General Service	0.00070	(0.00010)	0.060
Lighting	0.00050	0.00027	0.077

<u>Progress Energy Carolinas, Inc. (Progress or PEC) – Docket No. E-2, Sub 977</u>

On June 4, 2010, in Docket No. E-2, Sub 977, PEC filed its third annual DSM/EE rider application seeking to recover DSM/EE program costs, incentives, and carrying costs relative to 11 DSM and EE programs. The Commission held an evidentiary hearing on September 22, 2010, and on November 17, 2010, the Commission issued an Order approving an annual DSM/EE rider which allowed PEC the opportunity to recover $59.2 million in revenues from customers, subject to true up in its next DSM/EE rider proceeding. The period during which the DSM/EE rider established in this proceeding was in effect was the 12-month period December 1, 2010, through November 30, 2011.

To calculate the DSM rider component applicable to the rate period, PEC first allocated total company, or system, DSM costs and incentives to the North Carolina retail jurisdiction using an allocation factor of 85.9% based upon the ratio of the North Carolina retail demand to the PEC system retail demand at the hour of the annual summer peak. The allocation percentage is updated each May, and is based on the prior year's peak demand.

To calculate the EE rider component applicable to the rate period, PEC first allocated total company, or system, EE costs and incentives to the North Carolina retail jurisdiction using an allocation factor of 85.4% based upon the ratio of North Carolina retail sales to PEC system retail sales at the point of generation. The allocation percentage is updated each May and is based on the prior calendar year's retail sales.

North Carolina retail costs are then assigned to customer classes based on program design and participation, that is, costs are assigned to customer groups that directly benefit from the programs. Residential program costs are allocated solely to residential customers, general service program costs are allocated solely to general service customers, and lighting program costs are allocated solely to lighting customers. When a DSM or EE program benefits multiple classes of customers, EE costs are multiplied by rate class energy allocation factors and DSM costs are multiplied by rate class demand allocation factors for purposes of cost assignment.

The rate class allocation factors were developed assuming that customers electing to opt out of the DSM/EE rider will continue to do so. Since usage for opt-out customers was not forecasted, the energy allocation rate class factors were developed from the forecasted rate class usage, after subtracting actual sales for opt-out customers for the year ended March 31, 2010.[17] The energy allocation factors applicable to the residential, general service, and lighting classes based upon the forecast of rate class sales for the recovery period of December 2010 through November 2011 were 57.49%, 40.84%, and 1.67%, respectively. The demand allocation rate factors are based on the summer coincident peak demand for 2009, after subtracting actual sales for opt-out customers for the year ended March 31, 2010. PEC's forecast did not provide rate class coincident peak demands; therefore, the most recent historical data was deemed to be representative of future demand impacts. The demand allocation rate factors applicable to the residential, general service, and lighting classes for the recovery period of December 2010 through November 2011 were 63.43%, 36.57%, and 0.00%, respectively. For the recovery period December 2010 through November 2011, the Company's DSDR program, an EE program, was the only program of the 11 DSM and EE programs that benefitted multiple customer classes. Rate class energy allocation factors were employed to allocate costs related to PEC's DSDR program.

The calculated rate class DSM and EE revenue requirements are divided by rate class sales, after adjustment for opt-out customers, to establish the rate class DSM/EE rate. The following charts set forth the total costs and utility incentives, expressed in terms of revenue requirements, and the corresponding rate class DSM/EE rate to be collected from each class of customers as approved by the Commission in its

[17] Actual opt-out sales for the 12-months ending March 31, 2010, were 10,361,527,109 kWhs.

November 17, 2010 Order with respect to the 11 DSM and EE programs included in the Sub 977 proceeding (excluding gross receipts taxes and regulatory fee):

NC Rate Class	Adjusted NC Rate Class kWh Sales	Total Revenue Requirements	Total EE Rate
Residential	15,137,085,705	$24,563,857	$0.001623
General Service	10,755,231,182	13,407,256	0.001247
Lighting	440,804,029	337,685	0.000766
NC Retail	26,333,120,916	$38,308,798	

NC Rate Class	Adjusted NC Rate Class kWh Sales	Total Revenue Requirements	Total DSM Rate
Residential	15,137,085,705	$4,261,344	$0.000282
General Service	10,755,231,182	811,105	0.000075
Lighting	440,804,029	0	0.000000
NC Retail	26,333,120,916	$5,072,449	

NC Rate Class	Adjusted NC Rate Class kWh Sales	Adjusted EE EMF Revenue Requirement	Total EE EMF Rate
Residential	15,137,085,705	($ 425,137)	($0.000028)
General Service	10,755,231,182	(709,585)	(0.000066)
Lighting	440,804,029	(46,493)	(0.000105)
NC Retail	26,333,120,916	($1,181,215)	

NC Rate Class	Adjusted NC Rate Class kWh Sales	Adjusted DSM Revenue EMF Requirement	Total DSM EMF Rate
Residential	15,137,085,705	$ 242,925	$0.000016
General Service	10,755,231,182	(323,969)	(0.000030)
Lighting	440,804,029	0	0.000000
NC Retail	26,333,120,916	($ 81,044)	

Based upon the information set forth above, DSM/EE rider charges were set as follows, effective December 1, 2010, excluding gross receipts taxes and regulatory fee:

Rate Class	DSM/EE Rate (¢/kWh)	DSM/EE EMF (¢/kWh)	Uncollectibles Adjustment (¢/kWh)	DSM/EE Annual Rider (¢/kWh)
Residential	0.191	(0.001)	0.001	0.191
General Service	0.132	(0.010)	0.000	0.122
Lighting	0.077	(0.011)	0.000	0.066

PART 3: Cost Allocations Established Pursuant to G.S. 62-133.2(a2) and (a3)

The third part of this report provides the actual results of the cost allocations established by the Commission pursuant to G.S. 62-133.2(a2) and (a3), as enacted by Section 5 of Session Law 2007-397. G.S. 62-133.2 is the statute regarding fuel and fuel-related charge adjustment proceedings for electric public utilities.

Subsection (a2) of G.S. 62-133.2 provides that the fuel and fuel-related costs defined in subdivisions (4), (5), and (6) of subsection (a1) shall be recoverable from each class of customers as a separate component of the fuel rider. The fuel and fuel-related costs defined in subdivisions (4), (5), and (6) of subsection (a1) are as follows:

4) the total delivered noncapacity related costs, including all transmission charges, of all purchases of electric power by the electric public utility, that are subject to economic dispatch or economic curtailment (referred to hereafter as noncapacity purchased power costs);
5) the capacity costs associated with all purchases of electric power from qualifying cogeneration facilities and qualifying small power production facilities, as described in 16 U.S.C. §796, that are subject to economic dispatch by the electric public utility (referred to hereafter as qualifying facility capacity costs); and
6) except for those costs recovered pursuant to G.S. 62-133.8(h), the total delivered costs of all purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.8 or to comply with any federal mandate that is similar to the requirements of subsections (b), (c), (d), (e), and (f) of G.S. 62-133.8 (referred to hereafter as renewable energy costs).

Subdivision (1) of subsection (a2) requires that noncapacity purchased power costs be allocated among customer classes based on the electric public utility's North Carolina energy usage for the prior year in determining the specific component of the fuel rider for such costs. Subdivision (2) of subsection (a2) requires that qualifying facility capacity costs and renewable energy costs be allocated among customer classes based on the electric public utility's North Carolina peak demand for the prior year in determining the specific component of the fuel rider for these costs.

Therefore, generally speaking, subsection (a2) establishes the cost allocation requirements for noncapacity purchased power costs, qualifying facility capacity costs, and renewable energy costs. Further, subsection (a2) requires that such costs be recovered as separate components of the fuel rider and specific for each class of customers. One separate component is required for noncapacity purchased power costs for each customer class and another separate component is required for qualifying facility capacity costs and renewable energy costs. Subsection (a2) applies to the fuel and fuel-related charge adjustment proceedings of Duke and PEC until the Commission determines how the costs discussed above should be allocated in a general rate case for these companies. Subsection (a2) also limits the annual increase in the aggregate amount of such costs that are recoverable by an electric utility at two percent (2%) of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year.

Subsection (a3) applies only to Dominion NC Power and requires that only renewable energy costs be recovered from each class of customers as a separate component of the fuel rider. Specifically, subsection (a3) requires that renewable energy costs be allocated among customer classes based on the electric public utility's North Carolina peak demand for the prior year in determining the specific component of the fuel rider for such costs, until the Commission determines how these costs shall be allocated in a general rate case for Dominion NC Power. Subsection (a3) also limits the annual increase in the recoverable amount of renewable energy costs at one percent (1%) of Dominion NC Power's total North Carolina retail jurisdictional gross revenues for the preceding calendar year. During the preceding two fiscal years, Dominion NC Power did not have any costs to be recovered under this subsection.

The following sections provide the actual results of the cost allocations established by the Commission pursuant to G.S. 62-133.2(a2) in proceedings conducted and decided during the preceding two fiscal years ending June 30, 2011.

Duke Energy Carolinas, LLC (Duke) – Docket No. E-7, Sub 875

This fuel and fuel-related charge adjustment proceeding for Duke utilized a 12-month test period that consisted of the calendar year 2008. Duke filed its Application on March 4, 2009. The evidentiary hearing was held on June 2, 2009, and the Commission Order was issued on July 29, 2009.

To calculate the separate components of the fuel rider for noncapacity purchased power costs, Duke first allocated $187,788,000 of system noncapacity purchased power costs to the North Carolina retail jurisdiction using a factor of 68.36%, which was the ratio of the 2008 adjusted North Carolina retail megawatt-hour (MWh) usage to the 2008 adjusted system MWh usage. Thus, the amount of noncapacity purchased power costs allocated to the North Carolina retail jurisdiction equaled $128,378,000. Duke then allocated the $128,378,000 of North Carolina retail noncapacity purchased power costs among three classes of customers based on the ratio of the actual energy usage of each customer class to the total actual energy usage in the North Carolina retail jurisdiction in the prior year, 2008, as required by G.S. 62-133.2(a2)(1). Finally, Duke determined the separate component of the fuel rider for noncapacity purchased power costs for each customer class by dividing the amount of noncapacity purchased power costs allocated to each customer class by the 2008 adjusted MWh energy usage of each customer class. The noncapacity purchased power cost allocation and the resulting separate components of the fuel rider that were proposed by Duke are shown below:

Rate Class	2008 NC MWh Usage Allocation %	Allocated NC Noncapacity Purchased Power Costs $	2008 NC Adjusted MWh Usage	¢/kWh Component
Residential	37.20	47,697,000	20,864,546	0.2286
Commercial	38.80	49,847,000	21,858,309	0.2280
Industrial	24.00	30,834,000	13,214,133	0.2333
Total	100.00	128,378,000	55,936,988	

To calculate the separate component of the fuel rider for renewable energy costs, Duke first allocated $5,546,000 of system renewable energy costs to the North Carolina retail jurisdiction using a factor of 70.44%, which was the ratio of the North Carolina peak demand in megawatts (MW) to the total system peak demand that occurred in

2008. Thus, the amount of renewable energy costs allocated to the North Carolina retail jurisdiction equaled $3,907,000. Duke then allocated the $3,907,000 of North Carolina renewable energy costs among three classes of customers based on the contribution of each rate class to the North Carolina peak demand in the prior year, 2008, as required by G.S. 62-133.2(a2)(2). Finally, Duke determined the separate component of the fuel rider for renewable energy costs by dividing the amount of renewable energy costs allocated to each customer class by the 2008 adjusted MWh energy usage of each customer class. The renewable energy cost allocation and the resulting separate components of the fuel rider that were proposed by Duke are shown below:

Rate Class	2008 NC MW Demand Allocation %	Renewable Energy Costs $	2008 NC Adjusted MWh Usage	¢/kWh Component
Residential	42.40	1,655,000	20,864,546	0.0079
Commercial	38.50	1,505,000	21,858,309	0.0069
Industrial	19.10	746,000	13,214,133	0.0056
Total	100.00	3,907,000	55,936,988	

No party expressed any opposition with respect to the noncapacity purchased power or renewable energy cost amounts, allocations, or the separate components of the fuel rider proposed by Duke to recover such costs, and the Commission approved fuel and fuel-related cost adjustment riders that included these separate components.

Progress Energy Carolinas, Inc. (Progress or PEC) – Docket No. E-2, Sub 949

This fuel and fuel-related charge adjustment proceeding for PEC employed a 12-month test period consisting of the year ending March 31, 2009. PEC filed its Application on June 4, 2009. The evidentiary hearing was held on September 15, 2009, and the Commission issued its Order on November 16, 2009.

PEC included noncapacity purchased power costs, qualifying facility capacity costs, and renewable energy costs in its forecasted fuel and fuel-related costs for the year ending September 30, 2010, the period that the fuel and fuel-related cost rider established in this proceeding would be billed to customers.

To calculate the separate component of the fuel rider for noncapacity purchased power costs, PEC first allocated $212,360,586 of system noncapacity purchased power costs to the North Carolina retail jurisdiction using a factor of 65.31%, which was the ratio of the 2008 adjusted North Carolina retail MWh usage to the 2008 adjusted system usage. Thus, the amount of noncapacity purchased power costs allocated to the North Carolina retail jurisdiction equaled $138,689,247. PEC then allocated the $138,689,247 of North Carolina retail noncapacity purchased power costs among five customer rate classes based on the ratio of the energy usage of each customer rate class to the total energy usage in the North Carolina retail jurisdiction in the prior year, 2008, as required by G.S. 62-133.2(a2)(1). Finally, PEC determined the separate component of the fuel rider for noncapacity purchased power costs for each customer rate by dividing the amount of noncapacity purchased power costs allocated to each customer rate class by the forecasted North Carolina retail MWh sales for each customer rate class. The noncapacity purchased power cost allocations and the resulting separate components of the fuel rider proposed by PEC are shown below:

Rate Class	2008 NC MWh Sales Allocation %	Allocated NC Noncapacity Purchased Power Costs $	Forecasted MWh Sales	¢/kWh Component
Residential	39.99	55,459,885	15,309,108	0.362
Small Gen. Svc.	5.06	7,018,426	2,024,144	0.347
Medium Gen. Svc.	29.97	41,567,477	11,856,995	0.351
Large Gen. Svc.	23.79	33,000,617	9,137,744	0.361
Lighting	1.18	1,642,842	446,508	0.368
Total	100.00	138,689,247	38,774,500	

To calculate the separate component of the fuel rider for qualifying facility capacity cost and renewable energy costs, PEC first allocated $14,343,433 of system qualifying facility capacity costs ($11,927,400) and renewable energy costs ($2,416,033) to the North Carolina retail jurisdiction using a factor of 69.12%, which was the ratio of North Carolina peak demand in MW to the total system peak demand that occurred in 2008. Thus, the amount of qualifying facility capacity costs and renewable energy costs allocated to the North Carolina retail jurisdiction equaled $9,914,370. PEC then allocated the $9,914,370 of North Carolina retail qualifying facility capacity costs and renewable energy costs among five customer rate classes based on the contribution of each customer rate class to the North Carolina peak demand in the prior year, 2008, as required by G.S. 62-133.2(a2)(2). Finally, PEC determined the separate component of the fuel rider for qualifying facility capacity costs and renewable energy costs by dividing the amount of such costs allocated to each customer rate class by the forecasted North Carolina retail MWh energy usage of each customer rate class. The qualifying facility capacity costs and renewable energy costs allocations and the resulting separate components of the fuel rider that were proposed by PEC are shown below:

Rate Class	2008 NC MW Demand Allocation %	QF Capacity and Renewable Energy Costs $	Forecasted MWh Sales	¢/kWh Component
Residential	45.69	4,530,315	15,309,108	0.030
Small Gen. Svc.	4.96	492,085	2,024,144	0.024
Medium Gen. Svc.	33.30	3,301,816	11,856,995	0.028
Large Gen. Svc.	16.04	1,590,154	9,137,744	0.017
Lighting	0.00	0	0	0.000
Total	100.00	9,914,370	38,774,500	

PEC also calculated separate components of the experience modification factor (EMF) rider for the noncapacity purchased power costs and for the qualifying facility capacity costs and renewable energy costs for each customer rate class. To calculate these separate components, PEC first allocated the actual amounts of noncapacity purchased power costs and the qualifying facility capacity costs and renewable energy costs that were incurred during the test year to the North Carolina retail jurisdiction and to each customer rate class using the same allocation procedures used in the previous fuel and fuel-related charge adjustment proceeding for those forecasted costs. PEC then determined the amount of the under-recovery or over-recovery of these costs for each customer rate class by subtracting the actual amount of such costs from the actual amount of revenue generated by the separate component of the fuel rider established in the previous fuel and fuel-related charge adjustment proceeding for such forecasted costs. Finally, PEC divided the amount of the under-recovery or over-recovery of such costs for each customer rate class by the adjusted North Carolina retail MWh energy usage of each customer rate class during the test year. The separate components of the EMF rider for the noncapacity purchased power costs and the qualifying facility capacity costs and renewable energy costs proposed by PEC in this proceeding are shown below:

Rate Class	Noncapacity Purchased Power ¢/kWh	Qualifying Facility Capacity and Renewable Energy ¢/kWh
Residential	(0.057)	(0.022)
Small Gen. Svc.	(0.034)	(0.021)
Medium Gen. Svc.	(0.038)	(0.017)
Large Gen. Svc.	(0.033)	(0.010)
Lighting	(0.048)	0.000

No party expressed any opposition with respect to the noncapacity purchased power costs, qualifying facilities capacity costs, or renewable energy costs, allocations, or the separate components of the fuel rider or EMF rider proposed by PEC to recover such costs, and the Commission approved the fuel and fuel-related cost riders proposed by PEC that included such components.

Duke Energy Carolinas, LLC (Duke) – Docket No. E-7, Sub 934

This fuel and fuel-related charge adjustment proceeding for Duke utilized a 12-month test period that consisted of the calendar year 2009. Duke filed its application on March 2, 2010. The evidentiary hearing was held on June 2, 2010, and the Commission Order was issued on August 6, 2010.

G.S. 62-133.2(a2)(1) and (2) prescribe how the costs identified in subdivisions (4), (5), and (6) of subsection (a1) will be allocated among customer classes, until the Commission determines how these costs shall be allocated in a general rate case. In Duke's most recent general rate case, Docket No. E-7, Sub 909, the Commission exercised its authority to determine how such costs would be allocated for Duke for the first time. In the Order in that proceeding, the Commission concluded that the noncapacity purchased power costs, as defined in subdivision (4), shall be allocated on an energy only basis, using the same monthly energy factors and methodology currently used in the annual fuel proceedings. For qualifying facility capacity costs, as defined in subdivision (5), the Commission determined that such costs shall be allocated using composite production plant allocation factors as updated in the annual cost of service filings, using the cost of service methodology approved in the Company's most recent general rate case. Finally, for renewable energy costs, as defined in subdivision (6), the Commission determined that the energy-related costs of such purchases shall be allocated using the same energy allocation factors used for subdivision (4) costs, and the capacity-related costs of such purchases shall be allocated using the same composite production plant allocation factors used for subdivision (5) costs.

Therefore, in this fuel and fuel-related charge adjustment proceeding, the Commission allocated $108,154,000 of system noncapacity purchased power costs and $10,378,000 of the system renewable energy costs that were energy-related, using the same energy allocation factors and methodology used for most other types of fuel and fuel-related costs.

For the renewable energy costs that were capacity-related, the Commission first allocated $2,033,000 of such costs to the North Carolina retail jurisdiction using a factor of 69.07%, which was the ratio of the 2009 adjusted North Carolina retail MWh usage to the 2009 adjusted system MWh usage. Thus, the amount of renewable energy costs that were capacity-related allocated to the North Carolina retail jurisdiction equaled $1,404,000. The Commission then allocated the $1,404,000 among three classes of customers based on the composite production plant allocation factors used in the Company's most recent general rate case. Finally, the Commission determined a separate component of the fuel rider for the renewable energy costs that were capacity-related by dividing the amount of such costs allocated to each customer class by the 2009 adjusted MWh energy usage for each customer class. The allocation and resulting separate components of the fuel rider determined by the Commission for the renewable energy costs that were capacity-related are shown below:

Rate Class	2009 Production Plant Factors %	Renewable Costs Capacity-Related $	2009 Adjusted NC MWh Usage	¢/kWh Component
Residential	42.3729	595,000	21,013,802	0.0028
Commercial	38.5339	541,000	21,502,109	0.0025
Industrial	19.0932	268,000	11,376,803	0.0024
Total	100.0000	1,404,000	53,892,714	

Progress Energy Carolinas, Inc. (Progress or PEC) – Docket No. E-2, Sub 976

This fuel and fuel-related charge adjustment proceeding for PEC employed a 12-month test period consisting of the year ending March 31, 2010. PEC filed its application on June 4, 2010. The evidentiary hearing was held on September 21, 2010, and the Commission issued its Order on November 17, 2010.

PEC included noncapacity purchased power costs, qualifying facility capacity costs, and renewable energy costs in its forecasted fuel and fuel-related costs for the year ending November 30, 2011, the period that the fuel and fuel-related cost rider established in this proceeding would be billed to customers.

To calculate the separate component of the fuel rider for noncapacity purchased power costs, PEC first allocated $116,836,168 of system noncapacity purchased power costs to the North Carolina retail jurisdiction using a factor of 66.15%, which was the ratio of the 2009 adjusted North Carolina retail MWh usage to the 2009 adjusted system usage. Thus, the amount of noncapacity purchased power costs allocated to the North Carolina retail jurisdiction equaled $77,282,805. PEC then allocated the $77,282,805 of North Carolina retail noncapacity purchased power costs among five customer rate classes based on the ratio of the energy usage of each customer rate class to the total energy usage in the North Carolina retail jurisdiction in the prior year, 2009, as required by G.S. 62-133.2(a2)(1). Finally, PEC determined the separate component of the fuel rider for noncapacity purchased power costs for each customer rate class by dividing the amount of noncapacity purchased power costs allocated to each customer rate class by the forecasted North Carolina retail MWh energy usage for each customer rate class. The noncapacity purchased power cost allocations and the resulting separate components of the fuel rider proposed by PEC are shown below:

Rate Class	2008 NC MWh Sales Allocation %	Allocated NC Noncapacity Purchased Power Costs $	Forecasted MWh Sales	¢/kWh Component
Residential	41.03	31,708,227	15,323,399	0.207
Small Gen. Svc.	4.78	3,692,508	1,821,177	0.203
Medium Gen. Svc.	29.23	22,587,196	10,717,992	0.211
Large Gen. Svc.	23.75	18,352,010	8,372,208	0.219
Lighting	1.22	942,864	448,881	0.210
Total	100.00	77,282,805	36,683,656	

To calculate the separate component of the fuel rider for qualifying facility capacity cost and renewable energy costs, PEC first allocated $37,695,437 of system qualifying facility capacity costs ($12,480,720) and renewable energy costs ($25,214,717) to the North Carolina retail jurisdiction using a factor of 68.57%, which was the ratio of North Carolina peak demand in MW to the total system peak demand that occurred in 2009. Thus, the amount of qualifying facility capacity costs and renewable energy costs allocated to the North Carolina retail jurisdiction equaled $25,846,580. PEC then allocated the $25,846,580 of North Carolina retail qualifying facility capacity costs and renewable energy costs among five customer rate classes based on the contribution of each customer rate class to the North Carolina peak demand in the prior year, 2009, as required by G.S. 62-133.2(a2)(2). Finally, PEC determined the separate component of the fuel rider for qualifying facility capacity costs and renewable energy costs by dividing the amount of such costs allocated to each customer rate class by the forecasted North Carolina retail MWh energy usage of each customer rate class. The qualifying facility capacity costs and renewable energy costs allocation and the resulting separate components of the fuel rider that were proposed by PEC are shown below:

Rate Class	2008 NC MW Demand Allocation %	QF Capacity and Renewable Energy Costs $	Forecasted MWh Sales	¢/kWh Component
Residential	45.92	12,127,060	15,323,399	0.079
Small Gen. Svc.	6.46	1,669,365	1,821,177	0.092
Medium Gen. Svc.	30.16	7,796,118	10,717,992	0.073
Large Gen. Svc.	16.46	4,254,038	8,372,208	0.051
Lighting	0.00	0	448,881	0.000
Total	100.00	25,846,580	36,683,656	

PEC also calculated separate components of the EMF rider for the noncapacity purchased power costs and for the qualifying facility capacity costs and renewable energy costs for each customer rate class. To calculate these separate components, PEC first allocated the actual amounts of noncapacity purchased power costs and the qualifying facility capacity costs and renewable energy costs that were incurred during the test year to the North Carolina retail jurisdiction and to each customer rate class using the same allocation procedures used in the previous fuel and fuel-related charge adjustment proceeding for those forecasted costs. PEC then determined the amount of the under-recovery or over-recovery of these costs for each customer rate class by subtracting the actual amount of such costs from the actual amount of revenue generated by the separate component of the fuel rider established in the previous fuel and fuel-related charge adjustment proceeding for such forecasted costs. Finally, PEC divided the amount of the under-recovery or over-recovery of such costs for each customer rate class by the adjusted North Carolina retail MWh energy usage of each customer rate class during the test year. The separate components of the EMF rider for the noncapacity purchased power costs and the qualifying facility capacity costs and renewable energy costs proposed by PEC in this proceeding are shown below:

Rate Class	Noncapacity Purchased Power ¢/kWh	Qualifying Facility Capacity and Renewable Energy ¢/kWh
Residential	(0.119)	(0.021)
Small Gen. Svc.	(0.078)	(0.020)
Medium Gen. Svc.	(0.099)	(0.018)
Large Gen. Svc.	(0.109)	(0.011)
Lighting	(0.119)	0.000

No party expressed any opposition with respect to the noncapacity purchased power costs, qualifying facilities capacity costs, or renewable energy costs, allocations, or the separate components of the fuel rider or EMF rider proposed by PEC to recover such costs, and the Commission approved the fuel and fuel-related cost riders proposed by PEC that included such components.