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, 2013
Date Submitted: September 30, 2013

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, 2013.

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.

Virginia Electric and Power Company d/b/a Dominion North Carolina Power (DNCP), Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, Inc. (DEP), each have multiple proceedings described in this report, as follows:

	REPS Rider	**DSM/EE Rider**	**Fuel Rider**
DEC	2	2	2
DEP	2	2	2
DNCP	N/A	3	N/A

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, 2013. 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.

<u>Duke Energy Carolinas, LLC (DEC) – Docket No. E-7, Sub 984</u>

On March 11, 2011, DEC filed its third annual REPS rider application in which it sought recovery of $16,745,363 in incremental REPS expenses. DEC had agreed to provide REPS compliance services, including the procurement of renewable energy certificates (RECs), to the following wholesale entities (which are also elective power suppliers) subject to REPS requirements: Blue Ridge Electric Membership Corporation (EMC), the City of Concord, the Town of Dallas, the Town of Forest City, the City of Highlands, the City of Kings Mountain, and Rutherford EMC.

Because Blue Ridge EMC began receiving REPS compliance services from DEC during the "test period" in this proceeding (calendar year 2010), it was required to reimburse DEC through a "buy-in" payment for its share of all incremental REPS costs incurred by DEC through December 31, 2010.

DEC's total REPS compliance costs were allocated between itself and the wholesale customers by using a combined aggregate cost cap methodology. The combined total number of accounts at year end, by customer class, for both DEC'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 cases where a wholesale customer chose to self-supply a portion of its annual 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 was not supplied by DEC. This method resulted in the same cost per customer account for both DEC and the wholesale customers.

By Order dated August 31, 2011, the Commission approved DEC's REPS rider charges, as shown below, for a 12-month period beginning September 1, 2011, and ending August 31, 2012:

Customer Class	Monthly REPS Charge*	Monthly REPS EMF Charge*	Total Monthly REPS Rider **	Total Annual REPS Charges**
Residential	$ 0.37	$0.10	$ 0.49	$ 5.88
General Service	$ 1.87	$0.49	$ 2.44	$ 29.28
Industrial	$18.70	$7.37	$26.97	$323.64

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

These costs were allocated across DEC's 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>Duke Energy Carolinas, LLC (DEC) – Docket No. E-7, Sub 1008</u>

On March 12, 2012, DEC filed its fourth annual REPS rider application in which it sought recovery of $13,537,262 in incremental REPS expenses. DEC had agreed to provide REPS compliance services, including the procurement of RECs, to the following wholesale entities (which are also electric power suppliers subject to REPS requirements): Blue Ridge EMC, the City of Concord, the Town of Dallas, the Town of Forest City, the City of Highlands, the City of Kings Mountain, and Rutherford EMC.

In order to properly allocate incremental REPS costs between DEC and the wholesale entities, DEC used a combined aggregate cost cap methodology. This methodology combines the number of accounts subject to a REPS charge by customer class for both DEC North Carolina retail accounts and the wholesale entities' North Carolina retail accounts. In the cases where a wholesale entity has chosen to self-supply a portion of its annual REPS requirement (for example, using its SEPA allocation as allowed by G.S. 62-133.8(c)), the combined total number of accounts on which the cost allocation is based was adjusted on a pro-rata basis to recognize that a portion of the compliance requirement was not supplied by DEC.

A similar adjustment was made because DEC met part of its compliance requirement by reduced energy consumption through implementation of energy efficiency (EE) measures. Among DEC's retail customer classes, DEC allocated the benefits of its EE measures, known as energy efficiency certificates (EECs), to give consideration to the EE that was accomplished by each customer class.

By Order dated August 16, 2012, the Commission approved DEC's REPS rider charges, as shown below, for the 12-month period beginning September 1, 2012, and ending August 31, 2013:

Customer Class	Monthly REPS Charge*	Monthly REPS EMF Charge*	Total Monthly REPS Rider **	Total Annual REPS Charges**
Residential	$ 0.21	$0.00	$ 0.22	$ 2.64
General Service	$ 3.10	$0.08	$ 3.29	$ 39.48
Industrial	$19.28	$0.33	$20.29	$243.48

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

Thus, DEC's REPS costs were 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.)

Duke Energy Progress, Inc. (DEP) – Docket No. E-2, Sub 1000

On June 3, 2011, DEP filed its third annual REPS rider application in which it requested recovery of $22,672,548. DEP had agreed to provide REPS compliance services, including the procurement of renewable energy certificates (RECs) for the following wholesale entities (which are also electric power suppliers subject to REPS requirements): The Towns of Waynesville, Black Creek, Lucama, Sharpsburg and Stantonsburg. DEP proposed to allocate its REPS costs between its own retail customers and the customers of the wholesale entities based on the relative energy use of its retail customers versus those of the wholesale entities. This resulted in the wholesale entities being responsible for .45% of the costs during the test period (August 2010 – March 2011); .44% of the costs during the update period (April – July 2011); and .42% of the costs during the forecast period (December 2011 – November 2012). The Commission found this method of allocation to be appropriate in the Order it issued November 10, 2011, approving DEP's REPS rider. The monthly REPS riders approved by the Commission for the 12 months ending November 30, 2012, are as follows:

Customer Class	REPS Rider Charge Per Month*	REPS EMF Rider Charge Per Month*	Total Monthly REPS Charge **	REPS Rider Charge Per Year**
Residential	$ 0.53	$0.01	$ 0.56	$ 6.72
Commercial	$ 6.38	$0.12	$ 6.72	$ 80.64
Industrial	$43.16	$0.84	$45.52	$546.24

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

These costs were 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.)

Duke Energy Progress, Inc, (DEP) – Docket No. E-2, Sub 1020

On June 4, 2012, DEP filed its fourth annual REPS rider application in which it requested recovery of $21,265,938. DEP had agreed to provide REPS compliance services, including the procurement of RECs, for the following wholesale entities (which are also electric power suppliers subject to REPS requirements): the Towns of Black

Creek, Lucama, Sharpsburg and Stantonsburg, and the City of Waynesville. DEP proposed to allocate its REPS compliance costs between its own retail customers and the wholesale entities based on their relative energy use. This resulted in the wholesale entities being responsible for .43% of the costs during the test period (April 2011 – March 2012); .42% of the costs during the update period (April – July 2012); and .47% of the cost during the forecast period (December 2012 – November 2013).

DEP allocated its REPS costs among its customer classes in a manner that gave each class credit for the energy efficiency that it had accomplished via the Company's EE programs.

The Commission found these cost allocations to be appropriate in the Order it issued November 16, 2012, approving DEP's REPS rider. The monthly REPS riders approved by the Commission for the 12 months ending November 30, 2013, are as follows:

Customer Class	**REPS Rider Charge Per Month***	**REPS EMF Rider Charge Per Month***	**Total Monthly REPS Charge ****	**REPS Rider Charge Per Year****
Residential	$ 0.36	$0.05	$ 0.42	$ 5.04
Commercial	$ 6.20	$0.84	$ 7.28	$ 87.36
Industrial	$29.34	$3.84	$34.32	$411.81

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

DEP's REPS costs were allocated across its 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 preceding two fiscal years ending June 30, 2013.

Dominion North Carolina Power (DNCP) – Docket No. E-22, Sub 464

On September 1, 2010, in Docket No. E-22, Sub 464, DNCP filed a DSM/EE rider Application seeking to recover DSM/EE program costs, capital costs, and incentives relative to six DSM and EE programs. The Commission held an evidentiary hearing on April 13, 2011. On September 14, 2011, the Commission issued an Order Denying Approval of Program in Docket No. E-22, Sub 466, denying approval of one of the proposed six programs, the Company's proposed Commercial Distribution Generation (CDG) Program. On October 14, 2011, the Commission issued an Order approving an annual DSM/EE rider which allowed DNCP the opportunity to recover $1.1 million in revenues from customers, subject to true up in its next DSM/EE rider proceeding. Such Order also held that as the Commission had denied approval of the

CDG Program, it was not appropriate for DNCP to recover costs associated with this proposed program through Rider C. The Commission directed DNCP to file revised allocations, if any, and supporting schedules in the 2012 annual DSM/EE rider proceeding based on the Commission's denial of the CDG Program. The rate period for the DSM/EE rider established in this proceeding was the 12-month period January 1, 2011, through December 31, 2011. The DSM/EE rider became effective on November 1, 2011, subject to true-up in DNCP's 2012 annual DSM/EE rider proceeding.

In regard to jurisdictional allocation of costs, DNCP and the Public Staff had differing positions. DNCP's position was that allocation between jurisdictions should be based on participation in programs, while the Public Staff's position was that allocation between jurisdictions should be based on the peak demand and energy requirements of each jurisdiction. On March 2, 2011, DNCP and the Public Staff entered and filed an Agreement and Stipulation of Settlement (Stipulation), which was approved in the Commission's October 14, 2011 Order. Among other things, the Stipulation set forth that, for purposes of the Sub 464 proceeding, for purposes of calculating the portion of any DSM/EE EMF resulting from the 2011 calendar year, DNCP's system DSM/EE costs (including common costs) would be allocated to retail jurisdictions (including Virginia customers) only, and not to the wholesale jurisdiction. The generation-level coincident peak factor would be used for DSM programs and the generation-level energy allocation factor for EE programs. The loads and energy requirements of opted-out North Carolina retail and Virginia retail customers would not be deducted from the factor inputs for the purposes of jurisdictional allocation. Because DNCP and the Public Staff agreed to such jurisdictional allocation method for purposes of the Sub 464 proceeding only, the Stipulating Parties agreed to work together to determine the jurisdictional allocation methodology to be recommended in future proceedings and would present their joint or individual recommendations to the Commission for consideration in the next annual DSM/EE cost recovery rider proceeding.

Under the terms of the Commission-approved Stipulation, North Carolina retail costs would be assigned or allocated based on the particular classes at which each program is targeted. If a program is targeted at more than one class, the costs would be allocated between the participating classes in a reasonable manner, using the peak demand or energy allocation factors. Class assignment or allocation would take into account the impact of customers who have opted out.

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 October 14, 2011 Order with respect to the five DSM and EE programs included in the Sub 464 proceeding (excluding gross receipts taxes and regulatory fee):

NC Rate Class	Allocation Factor	Total Revenue Requirements	Adjusted NC Rate Class kWh Sales	Total DSM/EE Rate[2]
Residential	Directly Assigned	$805,438	1,592,654,129	$0.00053
Small General Service and Public Authority	[1]	193,463	852,755,579	0.00024
Large General Service	[2]	109,997	434,372,365	0.00026
Large General Service Variable Pricing	[3]	39,101	157,502,343	0.00026
Nucor Corporation		0		0.00000
Outdoor Lighting		0		0.00000
Traffic Lighting		0		0.00000
Total NC Retail		$1,147,999		

[1] Energy Usage Allocation Factor: 56.4752%; Coincident Peak Demand Allocation Factor: 55.5703%.
[2] Energy Usage Allocation Factor: 32.1104%; Coincident Peak Demand Allocation Factor: 33.4191%.
[3] Energy Usage Allocation Factor: 11.4144%; Coincident Peak Demand Allocation Factor: 11.0106%.

<u>Dominion North Carolina Power (DNCP) – Docket No. E-22, Sub 473</u>

On August 26, 2011, in Docket No. E-22, Sub 473, DNCP filed a DSM/EE rider Application seeking to recover DSM/EE program costs, capital costs, and incentives, relative to five DSM and EE programs. As required in the Commission's Sub 464 Cost Recovery Order, DNCP revised its request in the Sub 473 proceeding to remove the costs of the CDG Program which was denied approval by the Commission. The Commission held an evidentiary hearing on November 9, 2011, and on December 13, 2011, the Commission issued an Order approving an annual DSM/EE rider which allowed DNCP the opportunity to recover $2.0 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 January 1, 2012, through December 31, 2012.

In regard to jurisdictional allocation of costs, consistent with the Stipulation approved in the Sub 464 proceeding, system costs of DSM and EE programs were allocated to the North Carolina retail jurisdiction based on the North Carolina retail share in system retail coincident peak demand for DSM programs and energy requirements for EE programs. DNCP's system DSM/EE costs (including common costs) were allocated to retail jurisdictions (including Virginia customers) only, and not to the wholesale jurisdiction. On November 4, 2011, DNCP filed an addendum to the agreement that it had reached with the Public Staff in the Sub 464 proceeding. The addendum addressed the fact that the Virginia State Corporation Commission had imposed cost limits or caps on DNCP's DSM and EE expenditures. These caps made it possible that DNCP would limit the participation of its Virginia customers in some of its DSM and EE programs.

For the DSM rider component applicable to the rate period, DNCP used an allocation factor of 5.1270% to allocate total system DSM costs and incentives to the

[2] Includes gross receipts taxes based on a gross receipts factor of 1.03327.

North Carolina retail jurisdiction. For the EE rider component applicable to the rate period, DNCP allocated total system EE costs and incentives to the North Carolina retail jurisdiction using an allocation factor of 6.0284% based upon the ratio of North Carolina retail sales to total DNCP's system retail sales for the 12 months ended June 30, 2011.

Under the terms of the Commission-approved Stipulation, North Carolina retail costs would be assigned or allocated based on the particular classes at which each program is targeted. If a program is targeted at more than one class, the costs were allocated between the participating classes in a reasonable manner, using the peak demand or energy allocation factors. Class assignment or allocation would take into account the impact of customers who had opted out.

The calculated rate class DSM and EE revenue requirements were 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 be collected from each class of customers as approved by the Commission in its December 13, 2011 Order with respect to the five DSM and EE programs included in the Sub 473 proceeding (excluding gross receipts taxes and regulatory fee):

NC Rate Class	Allocation Factor	Total Revenue Requirements	Adjusted NC Rate Class kWh Sales	Total DSM/EE Rate[3]
Residential	Directly Assigned	$1,343,389	1,614,756,023	$0.00086
Small General Service and Public Authority	59.9385%	356,827	911,275,080	0.00040
Large General Service	28.4489%	162,399	435,662,790	0.00038
Large General Service Variable Pricing	11.6126%	63,245	157,522,179	0.00041
Nucor Corporation	0.0000%	0		0.00000
Outdoor Lighting	0.0000%	0		0.00000
Traffic Lighting	0.0000%	0		0.00000
Total NC Retail	100.0000%	$1,925,860		

Dominion North Carolina Power (DNCP) – Docket No. E-22, Sub 486

On August 21, 2012, in Docket No. E-22, Sub 486, DNCP filed a DSM/EE rider Application seeking to recover DSM/EE program costs, capital costs, and incentives relative to five DSM and EE programs. The Commission held an evidentiary hearing on November 20, 2012, and on December 14, 2012, the Commission issued an Order approving an annual DSM/EE rider which allowed DNCP the opportunity to recover $1.3 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 January 1, 2013, through December 31, 2013.

[3] Includes gross receipts taxes based on a gross receipts factor of 1.03327.

DNCP's system costs were 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 had elected not to participate and excluding customers in participating contract classes that were exempt or had opted out. No costs were allocated to the wholesale jurisdiction. The cost of DSM programs were allocated on the generation-level retail coincident peak. For the DSM rider component applicable to the rate period and the DSM EMF component, DNCP used an allocation factor of 5.0181% to allocate total system DSM costs and incentives to the North Carolina retail jurisdiction. The cost of EE programs are allocated on the basis of energy. For the EE rider component applicable to the rate period, DNCP allocated total system EE costs and incentives to the North Carolina retail jurisdiction using an allocation factor of 6.0680% based upon the ratio of North Carolina retail sales to total DNCP system retail sales for the 12 months ended June 30, 2012. For the EE EMF component, DNCP used an allocation factor of 6.0493% based upon the ratio of North Carolina retail sales to total DNCP system retail sales for the 12 months ended December 31, 2011.

North Carolina retail costs were assigned or allocated based on the particular classes at which each program is targeted. If a program is targeted at more than one class, the costs were allocated between the participating classes in a reasonable manner, using the peak demand or energy allocation factors. Class assignment or allocation took into account the impact of customers who had opted out. The applicable allocation factors for the Sub 486 proceeding related to programs targeted at more than one class of North Carolina retail customers are provided in the charts below.

The calculated rate class DSM and EE revenue requirements were divided by rate class sales, after adjustment for opt-out customers, to establish the rate class DSM/EE rate. The following charts also 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 December 14, 2012 Order with respect to the five DSM and EE programs included in the Sub 486 proceeding (excluding gross receipts taxes and regulatory fee):

NC Rate Class	**Allocation Factor**	**Total Revenue Requirements**	**Adjusted NC Rate Class kWh Sales**	**Total DSM/EE Rate[4]**
Residential	Directly Assigned	$995,821	1,619,876,717	$0.00063
Small General Service and Public Authority	63.4070%	191,912	869,954,885	0.00023
Large General Service	24.0243%	72,713	295,526,207	0.00026
Large General Service Variable Pricing	12.5687%	38,041	152,417,722	0.00026
Nucor Corporation	0.0000%	0		0.00000
Outdoor Lighting	0.0000%	0		0.00000
Traffic Lighting	0.0000%	0		0.00000
Total NC Retail	100.0000%	$1,298,487		

[4] Includes gross receipts taxes based on a gross receipts factor of 1.03327.

NC Rate Class	Allocation Factor	Total Revenue Requirements	Adjusted NC Rate Class kWh Sales	Total DSM/EE EMF Rate[5]
Residential	Directly Assigned	$450,761	1,619,876,717	$0.00029
Small General Service and Public Authority	64.7091%	204,426	869,954,885	0.00024
Large General Service	22.7751%	71,950	295,526,207	0.00025
Large General Service Variable Pricing	12.5158%	39,539	152,417,722	0.00027
Nucor Corporation	0.0000%	0		0.00000
Outdoor Lighting	0.0000%	0		0.00000
Traffic Lighting	0.0000%	0		0.00000
Total NC Retail	100.0000%	$766,676		

Duke Energy Carolinas, LLC (DEC) – Docket No. E-7, Sub 979

On March 31, 2011, DEC filed an Application for approval of its DSM/EE cost recovery rider (Rider 3) seeking to recover approximately $84.9 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 would be in effect was the 12-month period January 1, 2012, through December 31, 2012.

Rider 3 was designed to allow DEC 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 3 were 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 3 measures per the Settlement.

Revenue requirements for DEC's DSM and EE programs were 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 were 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 were 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 3, based upon DEC's 2010 cost of service study, the ratio of North Carolina retail kWh sales to total retail kWh sales was 72.7073%.

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

[5] Includes gross receipts taxes based on a gross receipts factor of 1.03327.

were allocated to the North Carolina retail jurisdiction based on North Carolina retail customers' contribution to retail system peak demand. For Rider 3, based upon DEC's 2010 cost of service study, the ratio of North Carolina retail contribution to total retail system peak demand was 74.7894%. The North Carolina retail revenue requirements were then allocated between residential and non-residential customers based upon each group's contribution to the North Carolina retail peak demand. For Rider 3, the allocation between residential and non-residential was 46.05% and 53.95%, respectively. Consistent with the Settlement and the Commission's February 9, 2010 Order, no costs were allocated to the wholesale jurisdiction.

The calculated rate class DSM and EE revenue requirements were divided by rate class sales, after adjustment for opt-out customers, to establish the rate class DSM/EE rate. The various categories of non-residential customers are a result of DEC's request for flexibility to manage its large customer "opt outs." On November 8, 2011, the Commission issued an Order authorizing DEC to recover the following amounts related to Rider 3 (including gross receipts taxes):

NC Rate Class	**Adjusted NC Rate Class kWh Sales**	**Total Revenue Requirements**	**Total DSM/EE Rate**
Residential, Vintage Year 3	21,006,908,000	$28,144,305	$0.001340
Residential, Vintage Year 1	21,006,908,000	20,775,242	0.000989
Non-Residential, EE, Vintage Year 3	25,816,002,000	10,470,554	0.000406
Non-Residential, DSM, Vintage Year 3	24,874,501,000	13,081,329	0.000526
Non-Residential, EE/DSM, Vintage Year 2	25,816,002,000	951,833	0.000037
Non-Residential, EE, Vintage Year 1	25,687,155,000	5,593,673	0.000218
Non-Residential, DSM, Vintage Year 1	25,440,044,000	5,208,825	0.000205
NC Retail		$84,225,761	

Duke Energy Carolinas, LLC (DEC) – Docket No. E-7, Sub 1001

On March 23, 2012, DEC filed an Application for approval of its DSM/EE cost recovery rider (Rider 4) seeking to recover approximately $92.5 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 would be in effect was the 12-month period January 1, 2013 through December 31, 2013.

Rider 4 was designed to allow DEC 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 4 were 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 the applicable vintage per the Settlement.

Revenue requirements for DEC's DSM and EE programs were 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 were 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 were 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 4, based upon DEC's 2011 kWh sales and peak demands, the ratio of North Carolina retail kWh sales to total retail kWh sales was 72.6972%.

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 were allocated to the North Carolina retail jurisdiction based on North Carolina retail customers' contribution to retail system peak demand. For Rider 4, based upon DEC's 2011 kWh sales and peak demands, the ratio of North Carolina retail contribution to total retail system peak demand was 74.4643%. The North Carolina retail revenue requirements were then allocated between residential and non-residential customers based upon each group's contribution to the North Carolina retail peak demand. For Rider 4, the allocation between residential and non-residential was 43.28% and 56.72%, respectively. Consistent with the Settlement and the Commission's February 9, 2010 Order, no costs were allocated to the wholesale jurisdiction.

The calculated rate class DSM and EE revenue requirements were divided by rate class sales, after adjustment for opt-out customers, to establish the rate class DSM/EE rate. The various categories of non-residential customers were a result of DEC's request for flexibility to manage its large customer "opt outs." On September 7, 2012, the Commission issued an Order authorizing DEC to recover the following amounts related to Rider 4 (including gross receipts taxes):

NC Rate Class	**Adjusted NC Rate Class kWh Sales**	**Total Revenue Requirements**	**Total DSM/EE Rate**
Residential, Vintage Years 3, 2, and 1[6]	20,920,337,000	$34,254,834	$0.001638
Non-Residential, EE, Vintage Year 4	26,947,143,000	20,040,852	0.000744
Non-Residential, DSM, Vintage Year 4	25,747,909,000	15,286,706	0.000594
Non-Residential, EE, Vintage Year 3	26,947,143,000	1,418,748	0.000053
Non-Residential, EE, Vintage Year 2	26,509,645,000	12,933,987	0.000488
Non-Residential, DSM, Vintage Year 2	25,413,539,000	3,596,290	0.000142
Non-Residential, EE, Vintage Year 1	26,378,016,000	4,078,607	0.000155
Non-Residential, DSM, Vintage Year 1	25,982,245,000	(349,411)	(0.000013)
NC Retail		$91,260,613	

[6] Includes $11,937,031 related to Vintage Year 2 True-up; $1,410,675 related to Vintage Year 1 True-up; and a ($1,200,000) adjustment related to the impact of an error in the Personalized Energy Report.

Duke Energy Progress, Inc. (DEP) – Docket No. E-2, Sub 1002

On June 3, 2011, in Docket No. E-2, Sub 1002, DEP filed a DSM/EE rider Application seeking to recover DSM/EE program costs, incentives, and carrying costs relative to 12 DSM and EE programs. The Commission held an evidentiary hearing on September 27, 2011, and on November 14, 2011, the Commission issued an Order approving an annual DSM/EE rider which allowed DEP the opportunity to recover $102.3 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, 2011, through November 30, 2012.

To calculate the DSM rider component applicable to the rate period, DEP first allocated total company, or system, DSM costs and incentives to the North Carolina retail jurisdiction using an allocation factor of 86.5% based upon the ratio of the North Carolina retail demand to the DEP 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, DEP first allocated total company, or system, EE costs and incentives to the North Carolina retail jurisdiction using an allocation factor of 85.5% based upon the ratio of North Carolina retail sales to DEP 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 were then assigned to customer classes based on program design and participation, that is, costs were assigned to customer groups that directly benefit from the programs. Residential program costs were allocated solely to residential customers, general service program costs were allocated solely to general service customers, and lighting program costs were allocated solely to lighting customers. When a DSM or EE program benefits multiple classes of customers, EE costs were multiplied by rate class energy allocation factors and DSM costs were 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 would 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, 2011.[7] 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 2011 through November 2012 were 57.31%, 41.03%, and 1.66%, respectively. The demand allocation rate factors were based on the summer coincident peak demand for 2010, after subtracting actual sales for opt-out customers for the year ended March 31, 2011. DEP'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

[7] Actual opt-out sales for the 12-months ending March 31, 2011, were 10,965,387,377 kWhs.

recovery period of December 2011 through November 2012 were 66.42%, 33.58%, and 0.00%, respectively. For the recovery period December 2011 through November 2012, the Company's DSDR program, an EE program, was the only program of the 13 DSM and EE programs that benefitted multiple customer classes. Rate class energy allocation factors were employed to allocate costs related to DEP's DSDR program.

The calculated rate class DSM and EE revenue requirements were 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 November 14, 2011 Order with respect to the 13 DSM and EE programs included in the Sub 1002 proceeding (excluding gross receipts taxes and regulatory fee):

NC Rate Class	Adjusted NC Rate Class kWh Sales	Rate Class Energy Allocation Factor	Total Revenue Requirements	Total EE Rate
Residential	15,449,253,075	57.31%	$37,921,369	$0.002455
General Service	11,060,984,152	41.03%	19,378,457	0.001752
Lighting	448,568,642	1.66%	420,371	0.000937
NC Retail	26,958,805,869		$57,720,197	

NC Rate Class	Adjusted NC Rate Class kWh Sales	Rate Class Demand Allocation Factor	Total Revenue Requirements	Total DSM Rate
Residential	15,449,253,075	66.42%	$6,601,439	$0.000427
General Service	11,060,984,152	33.58%	1,033,135	0.000093
Lighting	448,568,642	0.00%	0	0.000000
NC Retail	26,958,805,869		$7,634,573	

NC Rate Class	Adjusted NC Rate Class kWh Sales	Rate Class Energy Allocation Factor	Adjusted EE EMF Revenue Requirement[8]	Total EE EMF Rate
Residential	15,449,253,075	57.31%	$ 784,521	$0.000051
General Service	11,060,984,152	41.03%	422,139	0.000038
Lighting	448,568,642	1.66%	(39,957)	(0.000089)
NC Retail	26,958,805,869		$1,166,703	

NC Rate Class	Adjusted NC Rate Class kWh Sales	Rate Class Demand Allocation Factor	Adjusted DSM Revenue EMF Requirement[9]	Total DSM EMF Rate
Residential	15,449,253,075	66.42%	$ 138,034	$0.000009
General Service	11,060,984,152	33.58%	(303,062)	(0.000027)
Lighting	448,568,642	0.00%	0	0.000000
NC Retail	26,958,805,869		($ 165,028)	

[8] Total allocated costs of $32,572,751 less prior period DSM/EE rate adjustments of $31,406,048.
[9] Total allocated costs of $4,404,246 less prior period DSM/EE rate adjustments of $4,569,274.

Based upon the information set forth above, DSM/EE rider charges were set as follows, effective December 1, 2011, including gross receipts taxes and regulatory fee:

Rate Class	DSM/EE Rate (¢/kWh)	DSM/EE EMF (¢/kWh)	Uncollectibles Adjustment (¢/kWh)	GRT and Regulatory Fee (¢/kWh)	DSM/EE Annual Rider (¢/kWh)
Residential	0.288	0.006	0.002	0.010	0.306
General Service	0.185	0.001	0.000	0.006	0.192
Lighting	0.094	(0.009)	0.000	0.003	0.088

<u>Duke Energy Progress, Inc. (DEP) – Docket No. E-2, Sub 1019</u>

On June 4, 2012, in Docket No. E-2, Sub 1019, DEP filed a DSM/EE rider Application seeking to recover DSM/EE program costs, incentives, and carrying costs relative to 14 DSM and EE programs. The Commission held an evidentiary hearing on September 18, 2012, and on November 27, 2012, the Commission issued an Order approving an annual DSM/EE rider which allowed DEP the opportunity to recover $89.3 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, 2012, through November 30, 2013.

To calculate the DSM rider component applicable to the rate period, DEP first allocated total company, or system, DSM costs and incentives to the North Carolina retail jurisdiction using an allocation factor of 86.6% based upon the ratio of the North Carolina retail demand to the DEP 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, DEP first allocated total company, or system, EE costs and incentives to the North Carolina retail jurisdiction using an allocation factor of 85.9% based upon the ratio of North Carolina retail sales to DEP 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 were then assigned to customer classes based on program design and participation. That is, costs were assigned to customer groups that directly benefit from the programs. Residential program costs were allocated solely to residential customers, general service program costs were allocated solely to general service customers, and lighting program costs were allocated solely to lighting customers. When a DSM or EE program benefits multiple classes of customers, EE costs were multiplied by rate class energy allocation factors and DSM costs were 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 would 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, 2012.[10] 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 2012 through November 2013 were 57.79%, 40.53%, and 1.68%, respectively. The demand allocation rate factors were based on the summer coincident peak demand for 2011, after subtracting actual sales for opt-out customers for the year ended March 31, 2012. DEP'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 2012 through November 2013 were 66.80%, 33.20%, and 0.00%, respectively. For the recovery period December 2012 through November 2013, the Company's DSDR program, an EE program, was the only program of the 14 DSM and EE programs that benefitted multiple customer classes. Rate class energy allocation factors were employed to allocate costs related to DEP's DSDR program.

The calculated rate class DSM and EE revenue requirements were 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 November 27, 2012 Order with respect to the 14 DSM and EE programs included in the Sub 1019 proceeding (excluding gross receipts taxes and regulatory fee):

NC Rate Class	Adjusted NC Rate Class kWh Sales	Rate Class Energy Allocation Factor	Total Revenue Requirements	Total EE Rate
Residential	15,356,063,960	57.79%	$44,386,655	$0.002890
General Service	10,769,931,702	40.53%	28,788,633	0.002673
Lighting	445,387,173	1.68%	530,469	0.001191
NC Retail	26,571,382,835		$73,705,758	

NC Rate Class	Adjusted NC Rate Class kWh Sales	Rate Class Demand Allocation Factor	Total Revenue Requirements	Total DSM Rate
Residential	15,356,063,960	66.80%	$7,471,159	$0.000487
General Service	10,769,931,702	33.20%	1,044,916	0.000097
Lighting	445,387,173	0.00%	0	0.000000
NC Retail	26,571,382,835		$8,516,075	

NC Rate Class	Adjusted NC Rate Class kWh Sales	Rate Class Energy Allocation Factor	Adjusted EE EMF Revenue Requirement[11]	Total EE EMF Rate
Residential	15,356,063,960	57.79%	$1,259,333	$0.000082
General Service	10,769,931,702	40.53%	5,362,835	0.000498
Lighting	445,387,173	1.68%	(39,374)	(0.000088)
NC Retail	26,571,382,835		$6,582,794	

[10] Actual opt-out sales for the 12-months ending March 31, 2012, were 11,192,486,014 kWhs.
[11] Total allocated costs of $54,000,803 less prior period DSM/EE rate adjustments of $47,418,009.

NC Rate Class	Adjusted NC Rate Class kWh Sales	Rate Class Demand Allocation Factor	Adjusted DSM Revenue EMF Requirement[12]	Total DSM EMF Rate
Residential	15,356,063,960	66.80%	$ 686,570	$0.000045
General Service	10,769,931,702	33.20%	(200,797)	(0.000019)
Lighting	445,387,173	0.00%	0	0.000000
NC Retail	26,571,382,835		$ 485,773	

Based upon the information set forth above, DSM/EE rider charges were set as follows, effective December 1, 2012, including gross receipts taxes and regulatory fee:

Rate Class	DSM/EE Rate (¢/kWh)	DSM/EE EMF (¢/kWh)	Uncollectibles Adjustment (¢/kWh)	GRT and Regulatory Fee (¢/kWh)	DSM/EE Annual Rider (¢/kWh)
Residential	0.338	0.013	0.002	0.012	0.365
General Service	0.277	0.048	0.000	0.012	0.337
Lighting	0.119	(0.009)	0.000	0.004	0.114

[12] Total allocated costs of $6,819,048 less prior period DSM/EE rate adjustments of $6,333,275.

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

Subsections (a2) and (a3) of G.S. 62-133.2 set forth how the fuel and fuel-related costs defined in subdivisions (4), (5), and (6) of subsection (a1) are to be recovered in fuel and fuel-related charge adjustment proceedings. The fuel and fuel-related costs defined in subdivisions (4), (5), and (6) 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 purchased power costs).

Subsection (a2) provides that:

(a2) For those costs identified in subdivisions (4), (5), and (6) of subsection (a1) of this section, the annual increase in the aggregate amount of these costs that are recoverable by an electric public utility pursuant to this section shall not exceed two percent (2%) of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year. The costs described in subdivisions (4), (5), and (6) of subsection (a1) of this section shall be recoverable from each class of customers as a separate component of the rider as follows:

(1) For the costs described in subdivision (4) of subsection (a1) of this section, the specific component for each class of customers shall be determined by allocating these costs among customer classes based on the electric public utility's North Carolina energy usage for the prior year, as determined by the Commission, until the Commission determines how these costs shall be allocated in a general rate case for the electric public utility commenced on or after 1 January 2008.
(2) For the costs described in subdivisions (5) and (6) of subsection (a1) of this section, the specific component for each class of customers shall be determined by allocating these costs among customer classes based on the electric public utility's North Carolina peak demand for the prior year, as determined by the Commission, until the Commission determines how these costs shall be allocated in a general rate case for the electric public utility commenced on or after 1 January 2008.

Subsection (a3) provides as follows:

> (a3) Notwithstanding subsections (a1) and (a2) of this section, for an electric public utility that has fewer than 150,000 North Carolina retail jurisdictional customers as of 31 December 2006, the costs identified in subdivisions (1), (2), (6), and (7) of subsection (a1) of this section and the fuel cost component, as may be modified by the Commission, of electric power purchases identified in subdivision (4) of subsection (a1) of this section shall be recovered through the increment or decrement rider approved by the Commission pursuant to this section. For the costs identified in subdivision (6) of subsection (a1) of this section that are incurred on or after 1 January 2008, the annual increase in the amount of these costs shall not exceed one percent (1%) of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year. These costs described in subdivision (6) of subsection (a1) of this section shall be recoverable from each class of customers as a separate component of the rider. For the costs described in subdivision (6) of subsection (a1) of this section, the specific component for each class of customers shall be determined by allocating these costs among customer classes based on the electric public utility's North Carolina peak demand for the prior year, as determined by the Commission, until the Commission determines how these costs shall be allocated in a general rate case for the electric public utility commenced on or after 1 January 2008.

Subsection (a2) applies only to DEC and DEP and subsection (a3) applies only to DNCP. However, DNCP did not have any material costs to be recovered under subsection (a3) during the preceding two fiscal years.[13] Therefore, the remaining sections of this part of the report provide the actual results of cost allocations established by the Commission pursuant to G.S. 62-133.2(a2) in each of the fuel and fuel-related charge adjustment proceedings conducted and decided for DEC and DEP during the preceding two fiscal years ending June 30, 2013.

<u>Duke Energy Carolinas, LLC (DEC) – Docket No. E-7, Sub 982</u>

This fuel and fuel-related charge adjustment proceeding for DEC utilized a 12-month test period that consisted of the calendar year 2010. DEC filed its Application on March 9, 2011. The evidentiary hearing was held on June 7, 2011 and the Commission Order was issued on August 9, 2011.

As cited above, G.S. 62-133.2(a2)(1) and (2) determine how noncapacity purchased power costs, qualifying facility capacity costs, and renewable purchased power costs are to be allocated until the Commission determines how such costs are to be allocated in a general rate case commenced on or after January 1, 2008. On June 2, 2009, DEC filed an Application for a general rate increase in Docket No. E-7, Sub 909. In its Order in that docket issued on December 7, 2009, the Commission

[13] DNCP incurred a renewable purchased power cost amount of approximately $500 on a North Carolina retail basis during the test year in its most recent fuel charge adjustment proceeding, Docket No. E-22, Sub 485. Due to the relatively small amount, this cost was allocated on an energy basis rather than coincident peak demand.

exercised its authority to determine how such costs incurred on and after January 1, 2010 would be allocated among customer classes in DEC's fuel and fuel-related charge adjustment proceedings. In the Order dated December 7, 2009, the Commission ordered that noncapacity purchased power costs, as defined in subdivision (4), shall be allocated on an energy only basis, using the same monthly energy allocation factors and methodology that was then currently being used in annual fuel charge proceedings. For qualifying facility capacity costs, as defined in subdivision (5), the Commission ordered 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 purchased power costs, as defined in subdivision (6), which have both capacity-related costs and energy-related costs, the Commission ordered that the energy-related costs of such purchases shall be allocated using the same monthly energy allocation factors used to allocate 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, as discussed above.

Therefore, in this fuel and fuel-related charge adjustment proceeding, DEC allocated $125,041,000 of system noncapacity purchased power costs and $14,582,000 of the system renewable purchased power costs that were energy-related among the customers classes using the same monthly energy allocation factors and methodology used for most other types of fuel and fuel-related costs.

For the $2,884,000 of system renewable purchased power costs that were capacity-related, DEC first allocated $1,976,000 to the North Carolina retail jurisdiction using a factor of 68.50%, which was the ratio of the 2010 adjusted total North Carolina retail MWh usage to the 2010 adjusted system MWh usage. DEC then allocated the $1,976,000 among the residential, general service/lighting, and industrial customer classes based on the composite production plant allocation factors from the Company's 2009 cost of service study. Finally, DEC determined a separate component of the fuel rider for the renewable purchased power costs that were capacity-related by dividing the amount of such costs allocated to each customer class by the 2010 adjusted North Carolina retail MWh usage of each customer class. The cost allocation and resulting separate components of the rider proposed by DEC for the renewable purchased power costs that were capacity-related are shown below.

Rate Class	Production Plant Allocation Factors %	Renewable Purchase Costs Capacity – Related	2010 NC Adjusted MWh Usage	¢/kWh Component
Residential	45.9246	907,000	20,857,113	0.0043
Commercial	36.8485	728,000	21,791,070	0.0033
Industrial	17.2269	340,000	12,000,503	0.0028
Total	100.000	1,976,000	54,648,686	

No party expressed any opposition with respect to the noncapacity purchased power or renewable purchased power cost amounts, allocations, or the separate components of the fuel rider proposed by DEC to recover such costs, and the

Commission approved fuel and fuel-related cost riders that included these separate components.

Duke Energy Progress, Inc. (DEP) – Docket No. E-2, Sub 1001

This fuel and fuel-related charge adjustment proceeding for DEP employed a 12-month test period consisting of the year ending March 31, 2011. DEP filed its Application on June 3, 2011. The evidentiary hearing was held on September 27, 2011 and the Commission issued its Order on November 14, 2011.

DEP included noncapacity purchased power costs and renewable purchased power costs in its forecasted fuel and fuel-related costs for the year ending November 30, 2012, 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, DEP first allocated $94,578,729 of system noncapacity purchased power costs to the North Carolina retail jurisdiction using a factor of 66.59%, which was the ratio of the 2010 adjusted North Carolina retail MWh usage to the 2010 adjusted system usage. Thus, the amount of noncapacity purchased power costs allocated to the North Carolina retail jurisdiction equaled $62,980,053. DEP then allocated the $62,980,053 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, 2010, as required by G.S. 62-133.2(a2)(1). Finally, DEP 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 DEP are shown below:

Rate Class	**2010 NC MWh Sales Allocation %**	**Allocated NC Noncapacity Purchased Power Costs $**	**Forecasted MWh Sales**	**¢/kWh Component**
Residential	40.96	25,798,715	15,578,765	0.166
Small Gen. Svc.	4.07	2,562,976	1,887,035	0.136
Medium Gen. Svc.	30.21	19,025,628	11,220,612	0.170
Large Gen. Svc.	23.57	14,844,504	8,859,725	0.168
Lighting	1.19	748,230	361,866	0.207
Total	100.00	62,980,053	37,908,003	

To calculate the separate component of the fuel rider for renewable purchased power costs, DEP first allocated $76,189,754 of system renewable purchased power costs to the North Carolina retail jurisdiction using a factor of 69.09%, which was the ratio of North Carolina peak demand in MW to the total system peak demand that occurred in 2010. Thus, the amount of renewable purchased power costs allocated to the North Carolina retail jurisdiction equaled $52,637,754. DEP then allocated the

$52,637,754 of North Carolina retail renewable purchased power 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, 2010, as required by G.S. 62-133.2(a2)(2). Finally, DEP determined the separate component of the fuel rider for renewable purchases power 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 renewable purchased power cost allocations and the resulting separate components of the fuel rider that were proposed by DEP are shown below:

Rate Class	2010 NC MW Demand Allocation %	Renewable Purchased Power Costs $	Forecasted MWh Sales	¢/kWh Component
Residential	49.84	26,236,434	15,578,765	0.168
Small Gen. Svc.	5.65	2,972,628	1,867,035	0.158
Medium Gen. Svc.	28.10	14,790,227	11,220,612	0.132
Large Gen. Svc.	16.41	8,638,465	8,859,725	0.098
Lighting	0.0	0	361,866	0.000
Total	100.00	52,637,754	37,908,003	

DEP 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 purchased power costs for each customer rate class. To calculate these separate components, DEP first allocated the actual amounts of noncapacity purchased power costs and the qualifying facility capacity costs and renewable purchased power 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. DEP 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, DEP 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 for the qualifying facility capacity costs and renewable purchased power costs proposed by DEP in this proceeding are shown below:

Rate Class	Noncapacity Purchased Power ¢/kWh	Qualifying Facility Capacity and Renewable Purchased Power ¢/kWh
Residential	0.123	0.002
Small Gen. Svc.	0.158	0.014
Medium Gen. Svc.	0.137	0.003
Large Gen. Svc.	0.141	0.003
Lighting	0.148	0.000

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

Duke Energy Carolinas, LLC (DEC) – Docket No. E-7, Sub 1002

This fuel and fuel-related charge adjustment proceeding for DEC utilized a 12-month test period that consisted of the calendar year 2011. DEC filed its Application on March 7, 2012. The evidentiary hearing was held on June 12, 2012, and the Commission Order was issued on August 16, 2012.

G.S. 62-133.2(a2) (1) and (2) determine how noncapacity purchased power costs, qualifying facility capacity costs, and renewable purchased power costs are to be allocated until the Commission determines how such costs shall be allocated in a general rate case for the electric public utility commenced on or after January 1, 2008. DEC filed an Application for a general rate increase on June 2, 2009 in Docket No. E-7, Sub 909. In its Order in that docket issued on December 7, 2009, the Commission exercised its authority to determine how such costs would be allocated in DEC's fuel and fuel-related charge adjustment proceedings. In that Order, the Commission stated that noncapacity purchased power costs, as defined in subdivision (4), shall be allocated on an energy only basis, using the same monthly energy allocation factors and methodology that was then correctly being used in annual fuel charge proceedings. For qualifying facility capacity costs, as defined in subdivision (5), the Commission stated 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 purchased power costs, as defined in subdivision (6), which have both capacity-related costs and energy-related costs, the Commission ordered that the energy-related costs of such purchases shall be allocated using the same monthly energy allocation factors used to allocate 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, as discussed above.

Therefore, in this fuel and fuel-related charge adjustment proceeding, DEC allocated $160,034,000 of system noncapacity purchased power costs and $22,332,000 of the system renewable purchased power costs that were energy-related among the rate classes using the same monthly energy allocation factors and methodology used for most other types of fuel and fuel-related costs.

For the $4,548,000 of the system renewable purchased power costs that were capacity-related, DEC first allocated $3,311,000 to the North Carolina retail jurisdiction using a factor of 72.81%, based on the production plant allocation for the North Carolina retail jurisdiction from the Company's 2010 cost of service study. DEC then allocated the $3,311,000 among the residential, commercial/lighting, and industrial classes based on the production plant allocation factors for each class from the Company's 2010 cost of service study. Finally, DEC determined a separate component of the fuel rider for the renewable purchased power costs that were capacity-related by dividing the amount of such costs allocated to each customer class by the projected kWh usage of each customer class during the billing period that the riders established as a result of this proceeding would be in effect. The cost allocation and resulting separate components of the rider proposed by DEC for the renewable purchased power costs that were capacity-related are shown below:

Rate Class	Production Plant Allocation Factors %	Renewable Purchased Power Costs Capacity-Related $	Projected NC MWh Usage	¢/kWh Component
Residential	46.0422	1,524,000	20,759,438	0.0073
Commercial	37.5333	1,243,000	21,958,810	0.0057
Industrial	16.4244	544,000	12,295,936	0.0044
Total	100.0000	3,311,000	55,014,183	

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

<u>Duke Energy Progress, Inc. (DEP) – Docket No. E-2, Sub 1018</u>

This fuel and fuel-related charge adjustment proceeding for DEP employed a 12-month test period consisting of the year ending March 31, 2012. DEP filed its Application on June 4, 2012. The evidentiary hearing was held on September 18, 2012, and the Commission issued its Order on November 16, 2012.

DEP included noncapacity purchased power costs and renewable purchased power costs in its forecasted fuel and fuel-related costs for the year ending November 30, 2013, 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, DEP first allocated $136,655,674 of system noncapacity purchased power costs to the North Carolina retail jurisdiction using a factor of 67.42%, which was the ratio of the 2011 adjusted North Carolina retail MWh usage to the 2011 adjusted system MWh usage. Thus, the amount of noncapacity purchased power costs allocated to the North Carolina retail jurisdiction equaled $92,134,034. However, since DEP determined that the annual increase in the aggregate amount of its costs as defined in subdivisions (4), (5),and (6) of G.S. 62-132.2(a1) exceeded 2% of its North Carolina retail gross revenues in 2011 by $1,852,441, DEP subtracted this amount from the $92,134,034 of noncapacity purchased power costs allocated to the North Carolina retail jurisdiction. DEP then allocated the remaining $90,281,593 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, 2011, as required by G.S. 62-133.2(a2)(1).

Finally, DEP 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 DEP are shown below:

Rate Class	2011 NC MWh Sales Allocation %	Allocated NC Noncapacity Purchased Power Costs $	Forecasted MWh Sales	¢/kWh Component
Residential	41.59	37,552,099	15,247,888	0.246
Small Gen. Svc.	4.99	4,501,924	1,864,256	0.241
Medium Gen. Svc.	29.34	26,489,533	11,027,993	0.240
Large Gen. Svc.	22.88	20,655,872	8,912,419	0.232
Lighting	1.20	1,082,166	457,624	0.236
Total	100.00	90,281,593	37,510,180	

To calculate the separate component of the fuel rider for renewable purchased power costs, DEP first allocated $97,731,999 of system renewable purchased power costs to the North Carolina retail jurisdiction using a factor of 69.82%, which was the ratio of North Carolina peak demand in MW to the total system peak demand that occurred in 2011. Thus, the amount of renewable purchased power costs allocated to the North Carolina retail jurisdiction equaled $68,236,190. DEP then allocated the $68,236,190 of North Carolina retail renewable purchased power 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, 2011, as required by G.S. 62-133.2(a2)(2). Finally, DEP determined the separate component of the fuel rider for the renewable purchased power 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 renewable energy cost allocation and the resulting separate components of the fuel rider that were proposed by DEP are shown below:

Rate Class	2011 NC MW Demand Allocation %	Renewable Purchased Power Costs $	Forecasted MWh Sales	¢/kWh Component
Residential	49.68	33,898,033	15,247,888	0.222
Small Gen. Svc.	5.81	3,962,742	1,864,256	0.213
Medium Gen. Svc.	28.20	19,242,191	11,027,993	0.174
Large Gen. Svc.	16.32	11,133,223	8,912,419	0.125
Lighting	0.00	0	457,624	0.000
Total	100.00	68,236,190	37,510,180	

DEP also calculated separate components of the EMF rider for the noncapacity purchased power costs and for the renewable purchased power costs for each customer rate class. To calculate these separate components, DEP first allocated the actual amounts of noncapacity purchased power costs and the renewable purchased power 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. DEP 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, DEP 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 renewable purchased power costs proposed by DEP in this proceeding are shown below:

Rate Class	Noncapacity Purchased Power ¢/kWh	Qualifying Facility Capacity and Renewable Purchased Power ¢/kWh
Residential	0.112	0.038
Small Gen. Svc.	0.095	0.040
Medium Gen. Svc.	0.116	0.036
Large Gen. Svc.	0.114	0.025
Lighting	0.107	0.000

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