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
(Pursuant to N.C.G.S. § 62-133.9(i))

Date Due: September 1, 2015
Date Submitted: August 27, 2019

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EXECUTIVE SUMMARY

The Utilities Commission is providing this report to the Governor and the Joint Legislative Commission on Governmental Operations pursuant to N.C.G.S. § 62-133.9(i), which requires the Commission to submit a summary of proceedings conducted under N.C.G.S. § 62-133.9 every two years on September 1st. The report is to cover proceedings during the preceding two fiscal years, which for this report span the time period July 1, 2013, through June 30, 2015. This report is divided into five sections, one for each type of proceeding that the Commission conducted relative to N.C.G.S. § 62-133.9 from July 1, 2013, through June 30, 2015.

North Carolina General Statute Section 62-133.9 was enacted as part of Session Law 2007-397 (Senate Bill 3), which also established the Renewable Energy and Energy Efficiency Portfolio Standard (REPS) for North Carolina's electric power suppliers. Electric power suppliers can implement energy efficiency (EE) and demand-side management (DSM) measures to fulfill portions of their REPS obligations. Section 4.(a) of Senate Bill 3, codified as N.C.G.S. § 62-133.9, specifies that electric power suppliers shall use DSM and EE measures and supply-side resources to establish the least cost mix of demand reduction and generation measures that meets the electricity needs of their customers. Each electric power supplier that is required to file an Integrated Resource Plan (IRP) must include within that plan an assessment of DSM and EE and is required to submit cost-effective options that require participant incentives to the Commission for approval. Upon petition by an electric public utility, the Commission shall approve an annual rider to the utility's rates to allow it to recover all reasonable and prudent costs incurred for new DSM and EE measures, which includes only those programs instituted after January 1, 2007. Further, the Commission may approve incentives to electric public utilities for adopting and implementing new DSM and EE measures. The Commission is to determine the appropriate assignment of costs of new DSM and EE measures and shall assign those costs only to the class or classes of customers that directly benefit from the programs. Finally, none of the costs of new DSM or EE measures shall be assigned to an industrial or large commercial customer that notifies its utility that it has implemented or will implement alternative DSM and EE measures and elects not to participate in the utility's new DSM and EE measures.

North Carolina General Statute Section 62-133.8(a) contains the following definitions that apply to this report:

> "Demand-side management" means activities, programs or initiatives undertaken by an electric power supplier or its customers to shift the timing of electricity use from peak to non-peak demand periods. "Demand-side management" includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.

> "Energy efficiency measure" means an equipment, physical, or program change implemented after January 1, 2007, that results in less energy used to perform the same function. "Energy efficiency measure" includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources. "Energy efficiency measure" does not include demand-side management.

During the fall of 2014, the State's electric power suppliers provided assessments of the potential for DSM and EE as part of their integrated resource plans (IRPs)[1]. Pursuant to Session Law 2013-187, effective July 1, 2013, electric membership corporations (EMCs) are no longer required to participate in integrated resource planning proceedings before the Commission.

As noted above, Senate Bill 3 allows electric power suppliers to use energy savings from new EE and DSM programs toward their REPS obligations. During the two fiscal years covered by this report, the Commission approved 49 programs, including three pilot programs, and terminated seven programs. As of the end of the two-year period covered by this report, 11 program applications filed by DNCP, DEP and DEC were pending Commission approval.

Senate Bill 3 further provides that, upon petition by an electric public utility, the Commission shall approve an annual rider to the utility's rates to allow it to recover all reasonable and prudent costs incurred for new DSM and EE measures. Further, the Commission may approve incentives to utilities for adopting and implementing DSM and EE programs. During the two fiscal years covered by this report, DNCP, DEC and DEP each filed annual rider applications, and those riders allow the companies to recover their DSM/EE program costs as well as incentives. At the end of the two years covered by this report both DEP[2] and DEC[3] had outstanding DSM/EE Rider proceedings pending before the Commission.

As of the end of the period covered by this report, the DSM/EE riders for residential customers are as follows:

Electric Public Utility	**DSM/EE Rider Charges for Average Residential Customer Using 1,000 kWh** (including the regulatory fee)
DNCP	\$1.21/month
DEC	\$5.99/month
DEP	\$4.26/month

[1] Docket No. E-100, Sub 141.

[2] Docket No. E-2, Sub 1070.

[3] Docket No. E-7, Sub 1073.

In order to provide background and context, this report includes information for some Commission proceedings that occurred in prior fiscal years, and that may have been included in previous reports. In addition, this report acknowledges DSM/EE program applications that have been filed with the Commission recently and which fall into the next reporting period.

Throughout this report reference is made to various Commission dockets. Readers who wish to review the official record of any proceeding may do so by visiting the Commission's web site (www.ncuc.net), selecting "Dockets" from the main menu, selecting "Docket Search," and then entering the appropriate docket number.

SECTION 1: AMENDMENTS TO THE COMMISSION'S RULES IMPLEMENTING N.C.G.S. § 62-133.9

Prior to July 1, 2013, Commission Rule R8-60(b) specified that the IRP process was applicable to the North Carolina Electric Membership Corporation (NCEMC) and any individual electric membership corporation (EMC) to the extent that it is responsible for procurement of any or all of its individual power supply resources. However, with the ratification of Session Law 2013-187 on June 26, 2013, EMCs have been exempted from filing IRP's with the Commission, effective July, 1, 2013. On December 3, 2013, the Commission issued an Order Amending Commission Rules for this change in Docket No. M-100, Sub 140.

The Commission Rules that address EE and DSM are contained in Appendix A of this report.

Rule R8-60 Integrated Resource Planning and Filings

Rule R8-67 Renewable Energy and Energy Efficiency Portfolio Standard (REPS)

Rule R8-68 Incentive Programs for Electric Public Utilities and Electric Membership Corporations, Including Energy Efficiency and Demand-Side Management Programs

Rule R8-69 Cost Recovery for Demand-Side Management and Energy Efficiency Measures of Electric Public Utilities

SECTION 2: UTILITIES' DSM AND EE ASSESSMENTS FILED AS PART OF THEIR INTEGRATED RESOURCE PLANS

North Carolina General Statute § 62-133.9(c) requires each electric power supplier to which N.C.G.S. § 62-110.1[4] applies to include an assessment of DSM and EE in its IRP.

During the fall of 2014, IRPs were filed by the following electric public utilities in Docket No. E-100 Sub 141:

1. DNCP
2. DEC
3. DEP

The following is a summary of each electric power supplier's DSM/EE assessment that was included in its IRP.

1. <u>DNCP</u>

In its IRP filed in 2014, DNCP listed the then currently approved DSM programs in North Carolina as:

- Air Conditioner Cycling Program
- Residential Low Income Program
- Residential Lighting Program[5]
- Commercial Lighting Program[6]
- Commercial HVAC Upgrade
- Non-Residential Energy Audit Program
- Non-Residential Duct Testing & Sealing Program

[4] Session Law 2013-187, which took effect July 1, 2013, exempts all EMCs from the Commission's integrated resource planning proceedings.

[5] In its August 31, 2012 IRP, DNCP stated that as of December 31, 2011, its residential lighting program was concluded due to increased bulb efficiency standards that became effective January 1, 2012, as mandated by the Energy Independence and Security Act of 2007.

[6] On August 14, 2012, the Commission issued an Order Approving Suspension of Programs and Tariff Revisions (CHVAC/CL Program Suspension Order) in Docket Nos. E-22, Subs 467 and 469, granting the Company's request to modify Schedule HVAC and Schedule CL, respectively, in order to include language suspending the Commercial Lighting Program and Commercial HVAC Upgrade Program effective August 16, 2012. The Commercial Lighting Program and Commercial HVAC Upgrade Program are currently suspended. Subsequently, DNCP filed for Commission approval to reinitiate the Commercial HVAC Upgrade and Commercial Lighting Programs on a North Carolina-only basis. On December 16, 2013, the Commission approved the two NC-only Programs.

- Residential Bundle Program
    - Residential Home Energy Checkup
    - Heat Pump Upgrade Program
    - Residential Duct Testing and Sealing Program
    - Residential Heat Pump Tune-Up Program

DNCP stated that it has proposed additional programs in North Carolina and was also considering the following future programs:

- Non-Residential Window Film Program (proposed)
- Non-Residential Lighting Systems and Controls Program (proposed)
- Non-Residential Heating and Cooling Efficiency Program (proposed)
- Income and Age Qualifying Home Improvement Program
- Residential Appliance Recycling Program
- Qualifying Small Business Improvement Program
- Voltage Conservation Program
- Non-Residential Custom Incentive

DNCP stated that it had reviewed and rejected the following programs:

- Non-Residential HVAC Tune-Up Program
- Energy Management System Program
- Energy Star® New Homes Program
- Geo-Thermal Heat Pump Program
- Home Energy Comparison Program
- Home Performance with Energy Star® Program
- In-Home Energy Display Program
- Premium Efficiency Motors Program
- Programmable Thermostat Program
- Residential Refrigerator Turn-In Program
- Residential Solar Water Heating Program
- Residential Water Heater Cycling Program
- Residential Comprehensive Energy Audit Program
- Residential Radiant Barrier Program
- Residential Lighting Program (Phase II)
- Non-Commercial Refrigeration Program
- Cool Roof Program
- Non-Residential Data Centers Program
- Non-Residential Re-Commissioning
- Non-Residential Curtailable Service Program

DNCP provided a forecasted energy savings in 2015 due to its DSM and EE programs of 675,835 MWh (System-wide in Virginia and North Carolina).[7]

2. DEC

In 2013, DEC filed its application for approval of Energy Efficiency and Demand Side Management programs under in Docket No. E-7, Sub 1032. This new portfolio was a replacement for the Save-a-Watt programs approved in 2009. The Company received the Order for approval for these programs from the Commission in October 2013. DEC stated that it had the following DSM and EE programs available:

Residential:

- Appliance Recycling Program
- Energy Assessments Program
- Energy Efficiency Education Program
- Energy Efficient Appliances and Devices
- Heating, Ventilation and Air Conditioning (HVAC) Energy Efficiency Program
- Multi-Family Energy Efficiency Program
- My Home Energy Report
- Income-Qualified Energy Efficiency and Weatherization Program
- Power Manager

Non-Residential:

- Non-Residential Smart $aver® Energy Efficient Food Service Products Program
- Non-Residential Smart $aver® Energy Efficient HVAC Products Program
- Non-Residential Smart $aver® Energy Efficient IT Products Program
- Non-Residential Smart $aver® Energy Efficient Lighting Products Program
- Non-Residential Smart $aver® Energy Efficient Process Equipment Products Program
- Non-Residential Smart $aver® Energy Efficient Pumps and Drives Products Program
- Non-Residential Smart $aver® Custom Program
    - Non-Residential Smart $aver® Custom Energy Assessments Program
    - PowerShare®
    - PowerShare® CallOption

[7] Per Appendix 5E provided as part of Company's IRP filing in Docket No. E-100, Sub 141 on August 29, 2014.

Pilot Program (Non-Residential)

- Energy Management and Information Services Program

DEC stated in its IRP filed in 2014, that it had not rejected any cost-effective programs as a result of its EE and DSM program screening. The Company further stated in its IRP that it had launched aggressive marketing campaigns to make customers aware of DEC's 20 EE and DSM programs, successfully increasing customer adoption. The Company forecasted 2015 energy and capacity savings due to its DSM and EE programs of 664,000 MWh (energy savings) and 1,173 MW (capacity savings).

3. DEP

DEP listed its current portfolio of DSM/EE programs in its 2014 IRP as follows:

- Residential Home Energy Improvement
- Residential New Construction
- Residential Neighborhood Energy Saver (Low-Income)
- Residential Appliance Recycling Program
- Residential Energy Efficient Benchmarking Program
- Energy Efficient Lighting Program
- Commercial, Industrial, and Governmental (CIG) Energy Efficiency
- Small Business Energy Saver
- Distribution System Demand Response (DSDR) Program
- Residential EnergyWise Home
- CIG Demand Response Automation Program

DEP also stated in its IRP that it launched aggressive marketing campaigns to make customers aware of DEP's EE and DSM programs, successfully increasing customer adoption. The Company forecasted 2015 energy and capacity savings due to its DSM and EE programs of 638,000 MWh (energy savings) and 945 MW (capacity savings).

DEP listed the following projects representing program enhancements that are being considered for possible implementation:

- Small Business Demand Response
- Neighborhood Energy Saver Program
- Multi-Family
- K-12 Education
- Residential Energy Benchmarking

The Company noted that it had not rejected any cost-effective DSM/EE programs or measures since the previous biennial IRP was filed.

Finally, DEP stated that it offers the following informational and educational programs:

- Online Account Access
- “Lower My Bill” Toolkit
- Online Energy Saving Tips
- Energy Resource Center
- Large Account Management
- eSMART Kids Website
- Community Events

DEP noted that it had discontinued its Customized Home Energy Report educational program since its last biennial IRP filing.

SECTION 3: NEW DSM AND EE PROGRAMS

Senate Bill 3 allows electric public utilities to use energy savings from new EE programs toward their REPS obligations. Electric public utilities must file new program applications with the Commission. Programs initiated after the passage of Senate Bill 3 are considered "new."

1. DNCP's New DSM and EE Programs

On August 20, 2013, DNCP filed applications for the following eight programs, two of which had been previously approved and then suspended, and all of which were approved by the Commission on December 16, 2013:

- Commercial HVAC Upgrade Program (Docket No. E-22, Sub 467)
- Commercial Lighting Program (Docket No. E-22, Sub 469)
- Non-Residential Energy Audit Program (Docket No. E-22, Sub 495)
- Non-Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 496)
- Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 497)
- Residential Home Energy Check Up Program (Docket No. E-22, Sub 498)
- Residential Heat Pump Tune Up Program (Docket No. E-22, Sub 499)
- Residential Heat Pump Upgrade Program (Docket No. E-22, Sub 500)

On June 30, 2014, DNCP filed for approval of the following three DSM/EE programs:

- Non-Residential Heating and Cooling Efficiency Program (Docket No. E-22, Sub 507)
- Non-Residential Lighting Systems and Controls Program (Docket No. E-22, Sub 508)
- Non-Residential Window Film Program (Docket No. E-22, Sub 509)

On October 27, 2014, the Commission issued Orders approving the three programs. In Docket No. E-22 Sub 463, DNCP requested to end its system-wide Low Income Program, which request was later amended to include a request for approval of a North Carolina-only Low Income Program for calendar year 2015. On September 9, 2014, the Commission granted both of these requests.

2. DEC's New DSM and EE Programs

On February 9, 2010, in Docket Number E-7, Sub 831, the Commission issued an Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues (Save-a-Watt Order). The Save-a-Watt Order approved the application of DEC to initiate the Company's modified Save-a-Watt proposal establishing DSM/EE programs and a DSM/EE cost recovery mechanism. Save-a-Watt was approved as a pilot program for four years, ending on December 31, 2013. The following new programs were approved in that Order:

- Residential Energy Assessments
- Residential Smart Saver®
- Low Income Services
- Energy Efficiency Education Schools Program
- Non-Residential Energy Assessments
- Non-Residential Smart Saver®
- Non-Residential PowerShare® Call Option

On March 6, 2013, in Docket N. E-7, Sub 1032, DEC requested approval of a number of new DSM/EE programs to be effective January 1, 2014. These programs were:

Residential

- Appliance Recycling Program
- Energy Assessments Program
- Energy Efficiency Education Program
- Energy Efficient Appliances and Devices
- HVAC Energy Efficiency Program
- Multi-Family Energy Efficiency Program
- My Home Energy Report
- Income-Qualified Energy Efficiency and Weatherization Program
- Power Manager

Non-Residential

- Non-Residential Smart Saver® Energy Efficient Food Service Products Program
- Non-Residential Smart Saver® Energy Efficient HVAC Products Program
- Non-Residential Smart Saver® Energy Efficient IT Products Program
- Non-Residential Smart Saver® Energy Efficient Lighting Products Program
- Non-Residential Smart Saver® Energy Efficient Process Equipment Products Program
- Non-Residential Smart Saver® Energy Efficient Pumps and Drives Products Program
- Non-Residential Smart Saver® Custom Program
- Non-Residential Smart Saver® Custom Energy Assessments Program
- PowerShare®

Pilot Program

- Energy Management and Information Services Pilot[8]

Other new programs approved by the Commission were as follows:

- Residential My Home Energy Report (Docket No. E-7, Sub 1015)
- Residential Neighborhood Low-Income Program (Docket No. E-7, Sub 1004)
- Residential Appliance Recycling Program (Docket No. E-7, Sub 1005)
- Residential Power Manager (Docket No. E-7, Sub 1032)
- Small Business Energy Saver Program (Docket No. E-7, Sub 1055)

DEC also has two pilot programs that were approved during the two-year period covered by this report as follows:

- Smart Energy Now Pilot (Docket No. E-7, Sub 961)
- Business Energy Report Pilot Program (Docket No. E-7, Sub 1081)

The following are the programs that were terminated or ended during the two-year period covered by this report:

- Residential Energy Management System Pilot (Docket No. E-7 Sub 906)[9]
- Residential Retrofit Pilot (Docket No. E-7, Sub 952)[10]
- Home Energy Comparison Report Pilot (Docket No. E-7, Sub 954)[11]

3. DEP's New DSM and EE Programs

During the two fiscal years covered by this report, DEP filed for and received Commission approval of the following new programs:

- My Home Energy Report (Docket No. E-2, Sub 989)[12]
- Multi-Family Energy Efficiency Program (Docket No. E-2, Sub 1059)

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[8] On October, 20, 2014, DEC filed to terminate the program and the Commission issued its Order Approving Termination of Program on November 26, 2014.

[9] This pilot program was extended from its original ending date of September 30, 2010 until September 30, 2011.

[10] The Commission approved this pilot program on January 25, 2011. On October 18, 2012, DEC filed a letter with the Commission stating that the Company had decided not to implement the pilot program as a fully-deployed program.

[11] DEC withdrew this pilot on November 24, 2010, stating that it intended to file a similar program in 2011.

[12] This program replaced the Residential Service EE Benchmarking Program, approved by the Commission on December 12, 2014.

- Energy Efficiency Education Program (Docket No. E-2, Sub 1060
- Business Energy Report Pilot Program (Docket No. E-2, Sub 1072)

During previous years, DEP received Commission approval of the following programs:

- Residential Lighting Program (Docket No. E-2, Sub 950)
- Neighborhood Energy Saver Program (Low-Income) (Docket No. E-2, Sub 952)
- Appliance Recycling Program (Docket No. E-2, Sub 970)
- Commercial, Industrial, and Governmental Energy Efficiency (Docket No. E-2, Sub 938)
- Residential Home Energy Improvement (Docket No. E-2, Sub 936)
- Neighborhood Energy Saver (Low-Income) (Docket No. E-2, Sub 952)
- Distribution System Demand Response (DSDR) (Docket No. E-2, Sub 926)
- Residential EnergyWise™ (Docket No. E-2, Sub 927)
- Commercial, Industrial and Governmental Demand Response Automation (Docket No. E-2, Sub 953)[13]
- Residential New Construction (Docket No. E-2, Sub 1021)
- Small Business Energy Saver (Docket No. E-2 sub 1022)

The following are the programs that were terminated or ended during the two-year period covered by this report:

- Residential Service EE Benchmarking Program (Docket No. E-2 Sub 989)[14]
- Compact Fluorescent Light Pilot (Docket No. E-2 Sub 908)[15]
- Residential Home Advantage (Docket No. E-2, Sub 928)[16]
- Residential Solar Water Heating Pilot (Docket No. E-2, Sub 937)[17]

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[13] The Commission approved modifications to this program on December 10, 2013, as requested by DEP.

[14] This program was terminated by Commission Order dated December 12, 2014.

[15] This program was approved for only a short period of time – October 1, 2007 until December 30, 2007, or when customers purchased 200,000 qualifying CFLs, whichever was to occur first. This program terminated on December 30, 2007.

[16] DEP requested termination of this program on December 6, 2011. On January 31, 2012, the Commission granted DEP's request, closing the programs to new applications effective March 1, 2012, and cancelling the program altogether effective March 1, 2013.

[17] This pilot program was approved by the Commission to be effective through June 30, 2011 and was limited to 150 participants.

SECTION 4: COMMISSION PROCEEDINGS REGARDING DSM/EE COST RECOVERY

North Carolina General Statute Section 62-133.9(d) allows a utility to petition the Commission for approval of an annual rider to recover (1) the reasonable and prudent costs of new DSM and EE measures and (2) other incentives to the utility for adopting and implementing new DSM and EE measures. Further, Commission Rule R8-69(b) provides that the Commission will each year conduct a proceeding for each electric utility to establish an annual DSM/EE rider to recover DSM/EE related costs and utility incentives.

DSM/EE Rider Proceedings for DNCP

During the two-year period of July 1, 2013 through June 30, 2015, DNCP had two such proceedings before the Commission. Below is a discussion of each proceeding.

1. DNCP DSM/EE Cost Recovery Rider – Docket No. E-22, Sub 494

On August 20, 2013, DNCP filed its fourth DSM/EE incentives and cost recovery rider application in which it requested to recover costs and incentives for the following existing programs:

- Low Income Program
- Air Conditioner Cycling Program

DNCP also sought recovery of costs for the following six new programs (Phase II programs), and filed separate program applications for each of them:

- Non-Residential Energy Audit Program (Docket No. E-22, Sub 495)
- Non-Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 496)
- Residential Home Energy Check-Up Program (Docket No. E-22, Sub 498)
- Residential Duct Testing and Sealing Program (Docket No. E-22, Sub 497)
- Residential Heat Pump Tune-Up Program (Docket No. E-22, Sub 499)
- Residential Heat Pump Upgrade Program (Docket No. E-22, Sub 500)

Contemporaneously, the Company re-filed program applications for North Carolina-only Commercial HVAC Upgrade and Commercial Lighting Programs. DNCP requested that these programs be approved to begin accepting participants January 1, 2014.

On December 18, 2013, the Commission issued Orders Approving Programs for the two North Carolina-only programs and six Phase II programs in Docket No. E-22, Subs 467, 469, and 495-500.

In its rider application, DNCP sought recovery of $2,411,089 for DSM/EE program costs and incentives. DNCP's proposed riders, including the gross receipts tax and regulatory fee, were as follows:

Residential	0.092 cents/kWh
Small General Service and Public Authorities	0.084 cents/kWh
Large General Service	0.106 cents/kWh
6VP	0.091 cents/kWh

As part of its rider application, the Company also filed Addendum II to the Stipulation and Mechanism[18] as Attachment 1 to rider application, which memorialized the agreed-upon 100% cost assignment language between DNCP and the Public Staff related to the North-Carolina only programs[19].

The Public Staff filed testimony, as allowed by statute, on October 30, 2013. The Public Staff did not take issue with DNCP's rider application.

The Commission held an evidentiary hearing for this matter on November 13, 2013. No public witnesses appeared at the hearing.

On December 18, 2013, the Commission issued its Order, approving DNCP's requested charges related to DSM and EE program cost recovery. The Commission also

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[18] On October 14, 2011, in Docket No. E-22, Sub 464, the Commission issued its Order Approving Agreement and Stipulation of Settlement, Approving DSM/EE Rider, and Requiring Compliance Filing (2010 Cost Recovery Order). In the 2010 Cost Recovery Order, the Commission approved the Agreement and Stipulation of Settlement between the Public Staff and the Company (Stipulation), filed on March 2, 2011, as well as the Cost Recovery and Incentive Mechanism (Mechanism), attached as Stipulation Exhibit 1 to the Stipulation (collectively, Stipulation and Mechanism). On December 13, 2011, in Docket No. E-22, Sub 473, the Commission issued its Order Approving DSM/EE Rider and Requiring Customer Notice in DNCP's 2011 DSM/EE cost recovery proceeding (2011 Cost Recovery Order). The 2011 Cost Recovery Order also approved a first Addendum to the Stipulation and Mechanism (Addendum I) related to jurisdictional allocation of DSM/EE costs. Addendum I was then incorporated as part of the Stipulation and Mechanism.

[19] With regard to the two North Carolina-only programs, the Commission previously allowed DNCP to suspend these two system-wide programs in order to evaluate whether they could cost-effectively be offered only in North Carolina, and to work with the Public Staff on a more appropriate cost recovery methodology that would align recovery of program costs with the benefits of offering the programs only in North Carolina. On February 12, 2013, in Docket No. E-22, Sub 486, the Company filed "100% cost assignment language," in agreement with the Public Staff, for purposes of recovering the costs of offering these two programs on a North Carolina-only basis. On April 29, 2013, the Commission's Order Granting Conditional Approval of the cost assignment language in Docket E-22, Sub 486, conditionally approved DNCP's and the Public Staff's 100% cost assignment proposal, subject to (1) DNCP submitting updated program applications, including cost-effectiveness results, in accordance with Commission Rule R8-68; (2) Commission approval of the refiled North Carolina-only programs; (3) DNCP and the Public Staff submitting a signed amendment to the Addendum memorializing the agreed-upon 100% cost assignment language; and (4) DNCP sponsoring a witness in its annual DSM/EE cost recovery proceedings to address any Commission questions regarding cost recovery for these North Carolina-only programs.

approved Addendum II to the Stipulation and Mechanism as entered into by DNCP and the Public Staff and filed by DNCP as Attachment 1 to its application.

2. DNCP DSM/EE Cost Recovery Rider – Docket No. E-22, Sub 513

On August 19, 2014, DNCP filed an application for approval of DSM/EE incentives and cost recovery rider application in which it requested to recover costs and incentives for the Company's reasonable and prudent DSM/EE costs, common costs, taxes, net lost revenues (NLR), and a DSM/EE Program Performance Incentive (PPI). DNCP's Application requested an annual projected rate period revenue requirement of $3,953,211 to be recovered through its updated DSM/EE rider (Rider C) effective on and after January 1, 2015. DNCP also requested approval of a decrement DSM/EE Experience Modification Factor (EMF) rider (Rider CE) in the amount of ($993,184), to true up its actual costs and revenues received under Rider C rates in effect during the period July 1, 2013, through June 30, 2014. In supplemental testimony, filed on October 28, 2014, DNCP revised its requested revenue requirement to $3,952,850 for Rider C and ($998,690) for Rider CE. DNCP stated that the revised request would result in the following kilowatt-hours (kWh) charges: 0.121 cents per kWh for residential customers; 0.070 cents per kWh for small general service and public authority customers; 0.083 cents per kWh for large general service customers; and 0.053 cents per kWh for rate schedule 6VP customers (including the regulatory fee).

DNCP's application sought recovery of the cost of the following approved programs: (a) Phase I Air Conditioner Cycling Program; (b) Phase II DSM/EE programs: Non-residential Energy Audit Program, Non-residential Duct Testing & Sealing Program, Residential Home Energy Check-Up Program, Residential Duct Sealing Program, Residential Heat Pump Tune-Up Program, and Residential Heat Pump Upgrade Program; (c) Phase III DSM/EE programs: Non-residential Lighting Systems & Controls Program, Non-residential Heating & Cooling Efficiency Program, and Non-residential Window Film Program; (d) the recently-closed North Carolina-only Commercial HVAC Upgrade and Commercial Lighting Programs, for which there were still residual costs to be recovered; and (e) the North Carolina-only Low Income Program.

The Public Staff filed testimony on October 29, 2014, and on November 3, 2014, as allowed by N.C.G. S. § 62-15(d) and Commission Rule R1-19(e). No other parties intervened or presented testimony in this docket, and on November 12, 2014, the Commission held the evidentiary hearing as scheduled.

On December 19, 2014, the Commission issued its Order approving DNCP's requested charges related to DSM and EE program cost-recovery. The combined Rider C and Rider CE rates resulted in the following per kWh charges for usage during calendar year 2015: Residential - 0.121 ¢/kWh; SGS & Public Authority - 0.070 ¢/kWh; LGS - 0.083 ¢/kWh; 6VP - 0.053 ¢/kWh, NS - 0.00 ¢/kWh; Outdoor Lighting -0.00 ¢/kWh; and Traffic - 0.00 ¢/kWh (including the regulatory fee).

DSM/EE Rider Proceedings for DEC

During the two-year period of July 1, 2013 through June 30, 2015, DEC had three such proceedings before the Commission. Below is a discussion of each proceeding.

1. DEC Cost Recovery Rider – Docket No. E-7, Sub 1031

On March 6, 2013, DEC filed an application for approval of its DSM/EE Rider for 2014 (Rider 5) in Docket No. E-7, Sub 1031. Contemporaneous with this filing, DEC filed an application for approval of a new DSM and EE cost recovery and incentive mechanism, as well as a portfolio of new and existing DSM and EE programs, in Docket No. E-7, Sub 1032 (Sub 1032)[20]. Rider 5 consists of four components relating to the Save-a-Watt pilot approved by the Commission in Docket No. E-7, Sub 831: (1) a prospective Vintage 4 (2013) component to recover the second year of estimated net lost revenues for Vintage 4 EE programs; (2) a prospective Vintage 3 (2012) component to recover the third year of estimated net lost revenues from customers who participated in the Company's Vintage 3 EE programs from July 1, 2012 through December 31, 2012; (3) an EMF component which consists of the participation true-up for Vintage 3 (2012); and (4) an EMF component which consists of adjustments to the previous participation true-ups for Vintage 2 (2011) and Vintage 1 (2009/2010). In addition, since the Save-a-Watt pilot expired at the end of 2013, the Company filed for approval of its portfolio of new DSM and EE programs and a new cost recovery mechanism in Docket No. E-7, Sub 1032, to become effective January 1, 2014. Accordingly, Rider 5 included the recovery of estimated costs associated with year one (calendar year 2014, or Vintage 2014) of the new portfolio, as well as an incentive calculated pursuant to the proposed new mechanism. DEC requested that the Commission approve the following annual billing adjustments (including gross receipts tax and regulatory fee):[21]

Residential Billing Factors

Rider 5 Totals	0.4494 ¢/kWh

Non-Residential Billing Factors

Prospective Components:	
Vintage 4 EE participant	0.0107 ¢/kWh
EMF Component (Vintage 3 True-up):	
Vintage 3 EE participant	0.0790 ¢/kWh
Vintage 3 DSM participant	(0.0071) ¢/kWh

[20] This new cost recovery mechanism was to replace the cost recovery mechanism approved in Docket No. E-7, Sub 831 and its current portfolio of DSM/EE programs. Cost Recovery Mechanisms are discussed in further detail in section 5 of this report.

[21] As updated by the Company’s supplemental filing on May 23, 2013.

Vintage 2 True-up adjustment:	
Vintage 2 EE participant	0.0051 ¢/kWh
Vintage 1 True-up adjustment:	
Vintage 1 EE participant	(0.0017) ¢/kWh
Vintage 2014 Prospective Components:	
Vintage 2014 EE participant	0.0892 ¢/kWh
Vintage 2014 DSM participant	0.0798 ¢/kWh

Several parties intervened in the proceeding: the Public Staff; North Carolina Sustainable Energy Association (NCSEA); Carolina Utility Customers Association, Inc. (CUCA); North Carolina Waste Awareness and Reduction Network (NC WARN); and Southern Alliance for Clean Energy (SACE).

On June 4, 2013, the hearing was held as scheduled.

On August 19, 2013, in Sub 1032, the intervening parties and DEC filed an Agreement and Stipulation of Settlement (Stipulation) regarding the cost recovery and incentive mechanism.

On October 29, 2013, the Commission issued an Order approving DSM/EE riders for DEC. In that Order, the Commission approved DEC's calculation of its Rider subject to appropriate true-ups in future cost recovery proceedings consistent with the Stipulation, the Sub 831 Order, the EM&V Agreement, and other relevant Orders of the Commission, and subject to modification pursuant to the Commission's determination in Docket No. E-7, Sub 1032[22]. The approved Rider EE was calculated to recover costs of $155,727,621 (including the regulatory fee), and was based on the forecasted kWh sales for the 2014 rate period. The revised Rider EE provided for a Residential charge of 0.4241 cents per kWh. The impact of this change on the typical residential bill using 1000 kWh per month was an increase of $2.60 per month compared to the rider previously in effect.

[22] DEC calculated its proposed rates for Rider 5, which include (a) the second year of estimated net lost revenues for Vintage Year 4 EE programs; (b) the third year of estimated net lost revenues for Vintage Year 3 EE programs for customers who participated in the Company's Vintage Year 3 EE programs from July 1, 2012 through December 31, 2012; (c) the Vintage Year 3 EMF component; and (d) adjustments to the EMF components for Vintage Years 1 and 2, all determined in accordance with the modified save-a watt approach described in the Settlement and approved, with certain modifications, in the Commission's Sub 831 Order, the Sub 938 Waiver Order, the Sub 938 Second Waiver Order, the Sub 831 Found Revenues Order, and the Sub 979 Order. Rider 5 also includes the rates associated with year one of the proposed portfolio of EE and DSM programs and cost recovery mechanism as filed in the Sub 1032 Proceeding, which are subject to adjustment in accordance with the Commission's pending ruling in the Sub 1032 Proceeding. Accordingly, the calculation of Rider 5 and the resulting billing factors as provided in this Order should become effective for the rate period January 1, 2014 through December 31, 2014, subject to appropriate true-ups in future cost recovery proceedings consistent with the Settlement, the Sub 831 Order, and all other relevant Orders of the Commission, and to adjustment pursuant to the Commission's pending ruling in Sub 1032.

Also in that Order, the Commission required DEC to explore and develop a consensus position regarding the merits of conducting a study or survey of opted-out customers, and if deemed to be a prudent endeavor, the parameters of such a study through a collaborative of the interested intervening parties.

2. DEC DSM/EE Cost Recovery Rider – Docket No. E-7, Sub 1050

On March 5, 2014, DEC filed an application for approval of its DSM/EE Rider for 2015 (Rider 6). Rider 6 encompassed components relating to both the Company's Save-a-Watt pilot approved in Docket No. E-7, Sub 831, as well as the new cost recovery mechanism and portfolio of programs approved by the Commission in Docket No. E-7, Sub 1032. The prospective components of Rider 6 included an estimate of the third year of net lost revenues for Vintage 4 of the Company's EE programs under Save-a-Watt; an estimate of the remaining half year of net lost revenues for Vintage 3 EE programs; estimates of the revenue requirements for Vintage 2015 DSM and EE programs under the new mechanism; and an estimate of the second year of net lost revenues for Vintage 2014 EE programs under the new mechanism. The Rider 6 Experience Modification Factor (EMF) included the following true-ups under Save-a-Watt: a true-up of Vintage 4 DSM and EE programs; a true-up of the second year of net lost revenues for Vintage 3 EE programs; a true-up of the third year of net lost revenues for Vintage 2 EE programs; and the final true-up of the Save-a-Watt pilot. In supplemental testimony filed on March 18, 2014, DEC requested that the Commission approve the following annual billing adjustments (including gross receipts tax and regulatory fee):

Residential Billing Factors

Rider 6 Prospective Component	0.3348 ¢/kWh
Rider 6 EMF Component	0.2669 ¢/kWh

Non-Residential Billing Factors

Prospective Components:	
Vintage 3 EE participant	0.0045 ¢/kWh
Vintage 4 EE participant	0.0217 ¢/kWh
Vintage 2014 EE participant	0.0204 ¢/kWh
Vintage 2015 EE participant	0.0861 ¢/kWh
Vintage 2015 DSM participant	0.1098 ¢/kWh

EMF Components:	
Vintage 4 EE participant	0.0404 ¢/kWh
Vintage 4 DSM participant	0.0032 ¢/kWh
Vintage 3 EE participant	0.0217 ¢/kWh
Vintage 3 DSM participant	0.0059 ¢/kWh
Vintage 2 EE participant	0.0106 ¢/kWh

Vintage 2 DSM participant	0.0000 ¢/kWh
Vintage 1 EE participant	0.0003 ¢/kWh
Vintage 1 DSM participant	(0.0001) ¢/kWh

Intervening parties were as follows: the Public Staff; CUCA, Walmart-Stores East, LP, and Sam's East, Inc. (Walmart); Carolina Industrial Group for Fair Utility Rates III (CIGFUR III); NCSEA, and SACE.

On May 14, 2014, the Public Staff filed a letter with the Commission stating that its audit of the costs of the Save-a-Watt portfolio of programs from June 1, 2009 to December 31, 2013 would not be completed by the June 3, 2014 hearing date. The Public Staff notified the Commission that it planned to complete the audit, work to resolve any issues with DEC, and inform the Commission and parties to this proceeding of the results of the audit by August 1, 2014, including a recommendation for any changes to Rider 6 or future riders, if appropriate.

On June 3, 2014, the hearing was held as scheduled.

DEC testified that its Low-Income Energy Efficiency and Weatherization Assistance program had not been implemented as of the June 3, 2014 hearing, due to the influence of other government supported programs that target the same customers. However, the Company stated that it intended to ramp up this program as part of its other low-income targeted programs by the end of June 2014.

On July 30, 2014, the Public Staff filed a letter with the Commission stating that it was in the process of working with DEC to finalize the results of the Save-a-Watt audit and expected it would take an additional two weeks to complete such audit. The Public Staff notified the Commission that after completion of the audit, the Public Staff would file any recommendation for changes to Rider 6 or future riders, if appropriate.

On October 1, 2014, the Public Staff filed a letter with the Commission stating the results and recommendations concerning its audit of the Save-a-Watt program costs. On October 2, 2014, DEC filed revised exhibits to reflect the adjustments proposed by the Public Staff in its October 1, 2014 letter.

On October 29, 2014, the Commission issued an Order approving the calculation of Rider EE as filed by DEC and revised by the Public Staff, and the resulting billing factors (as set forth in Revised McGee Exhibit 1, filed on October 2, 2014[23]), to go into effect for the rate period January 1, 2015 through December 31, 2015, subject to appropriate true-ups in future cost recovery proceedings consistent with the Sub 831 Order, the Sub 1032 Order, and other relevant orders of the Commission. The approved Rider EE was calculated to recover costs of $206,430,755 (including the regulatory fee), and was based on the forecasted kWh sales for the 2015 rate period. The revised Rider EE provided for

[23] On this date DEC filed revised exhibits reflecting the adjustments proposed by the Public Staff as a result of its audit of the costs of the Save-a-Watt portfolio of programs incurred from June 1, 2009 through December 31, 2013, and as detailed in the Public Staff's October 1, 2014 letter filing in this docket.

a Residential increment of 0.5989 cents per kWh. The impact of this change on the typical residential customer using 1,000 kWh per month was an increase of $1.88 per month as compared to the rider previously in effect.

The Commission also found that DEC should notify the Commission of any further delays in its low-income program. Further, the Commission ordered DEC to incorporate the recommendations made by Public Staff witness Floyd into future EM&V reports filed with the Commission in subsequent DSM/EE rider proceedings, as well as the continuation of the Collaborative as a forum to discuss CHP, and to work with stakeholders to find ways of increasing DSM and EE program impacts and participation, including programs designed to decrease opt-outs.

3. DEC DSM/EE Cost Recovery Rider – Docket No. E-7, Sub 1073

On March 4, 2015, DEC filed an application for approval of its DSM/EE Rider (Rider 7) for 2016. Rider 7 encompassed components relating to both DEC's Save-a-Watt pilot approved in Docket No. E-7, Sub 831, as well as the new cost recovery mechanism and portfolio of programs approved by the Commission in Docket No. E-7, Sub 1032. The prospective components of Rider 7 included estimates of the revenue requirements for Vintage 20 DSM and EE programs under the new mechanism; and an estimate of the third year of net lost revenues for Vintage 2014 EE programs and the second year of net lost revenues for Vintage 2015 EE programs under the new mechanism. The Rider 7 Experience Modification Factor (EMF) included the following true-ups: a true-up of Vintage 2014 DSM and EE programs; and the final true-up of the Save-a-Watt pilot. DEC requested that the Commission approve the following annual billing adjustments (including the regulatory fee):[24]

Residential Billing Factors

Rider 7 Prospective Component	0.3361 ¢/kWh
Rider 7 EMF Component	0.0260 ¢/kWh

Non-Residential Billing Factors

Prospective Components:	
Vintage 2014 EE participant	0.0256 ¢/kWh
Vintage 2015 EE participant	0.0345 ¢/kWh
Vintage 2016 EE participant	0.2164 ¢/kWh
Vintage 2016 DSM participant	0.0709 ¢/kWh
EMF Components*:*	
Vintage 2014 EE participant	0.0150 ¢/kWh
Vintage 2014 DSM participant	(0.0044) ¢/kWh
Vintage 4 EE participant	0.0326 ¢/kWh

[24] Amounts are per updated supplemental filing of DEC filed on May 15, 2015.

Vintage 4 DSM participant	0.0005 ¢/kWh
Vintage 3 EE participant	0.0261 ¢/kWh
Vintage 3 DSM participant	(0.0017) ¢/kWh
Vintage 2 EE participant	0.0148 ¢/kWh
Vintage 2 DSM participant	0.0019 ¢/kWh
Vintage 1 EE participant	0.0027 ¢/kWh
Vintage 1 DSM participant	0.0017 ¢/kWh

Intervening parties in this proceeding were as follows: The Public Staff; NCSEA; CUCA; CIGFUR III, and SACE.

On June 2, 2015, the Commission held its evidentiary hearing in this matter, which as of the due date of this report was currently pending before the Commission.

DSM/EE Rider Proceedings for DEP

1. DEP DSM/EE Cost Recovery Rider – Docket No. E-2 Sub 1030

On June 12, 2013, DEP filed an application and the associated testimony and exhibits of Robert P. Evans for the approval of a DSM/EE rider to recover reasonable and prudent forecasted DSM/EE costs, carrying costs, incremental administrative and general (A&G) costs, capital costs, taxes, and incentives, including net lost revenue (NLR) and the program performance incentive (PPI). In addition, DEP asked for approval of a DSM/EE EMF rider and, pursuant to Commission Rule R8-69(b)(2), recovery through the DSM/EE EMF of its post-test-year costs, including carrying costs and incentives incurred up to 30 days prior to the hearing in this proceeding. DEP stated that the rider and EMF were intended to allow DEP to recover $74,770,116 of DSM/EE expenses and incentives. DEP requested that the Commission approve the following annual billing factor adjustments (including the gross receipts tax and the regulatory fee):

Residential:

DSM/EE Rate	0.324 ¢/kWh
DSM/EE EMF Rate	(0.019) ¢/kWh
Total	0.305 ¢/kWh

General Service:

DSM/EE Rate	0.268 ¢/kWh
DSM/EE EMF Rate	0.013 ¢/kWh
Total	0.281 ¢/kWh

Lighting:

DSM/EE Rate	0.114	¢/kWh
DSM/EE EMF Rate	(0.006)	¢/kWh
Total	0.108	¢/kWh

The following parties intervened in the proceeding: the Public Staff, CUCA, and SACE.

The Commission held a hearing for this matter on September 17, 2013.

On November 22, 2013, the Commission issued a Notice of Decision and Order in which it approved DEP's proposed DSM/EE rates and EMF for service rendered on or after December 1, 2013. That Order stated that a final order, including findings of fact and conclusions, would be issued at a later date. In the Final Order issued on January 23, 2014, the Commission determined that the revenue requirements for each class, excluding gross receipts tax and regulatory fee, are as follows:

Rate Period

Residential	$48,039,813
General Service	26,891,475
Lighting	461,392
Total	$75,392,680

DSM/EE EMF

Residential	$(1,606,203)
General Service	1,286,113
Lighting	(29,138)
Total	$(349,228)

The Commission further determined that the total DSM/EE annual riders, including the DSM/EE rate and the DSM/EE EMF (including the gross receipts tax and the regulatory fee), approved by the Commission are:

Rate Class	Total DSM/EE Rider
Residential	0.297 cents per kWh
General Service	0.247 cents per kWh
Lighting	0.097 cents per kWh

The Commission ordered DEP to establish a collaborative, similar to the one in place for DEC, in order to discuss with interested stakeholders potential new programs, or modifications to existing programs, that would help DEP achieve additional EE savings.

Further, the Commission found it appropriate for the collaborative to consider and develop a position regarding either a limited study or survey of customers who have opted-out of DEP's DSM/EE programs, and for DEP to report the results and conclusions or recommendations as part of its 2014 DSM/EE rider filing.

2. DEP DSM/EE Cost Recovery Rider – Docket No. E-2, Sub 1044

On June 18, 2014, DEP filed an application and the associated testimony and exhibits of its witnesses for the approval of a DSM/EE rider to recover reasonable and prudent forecasted DSM/EE costs, including carrying costs, NLR, PPI and an EMF. In addition, DEP asked for approval of a DSM/EE EMF rider and, pursuant to Commission Rule R8-69(b)(2), recovery through the DSM/EE EMF of its post-test-year costs, including carrying costs and incentives incurred up to 30 days prior to the hearing in this proceeding. DEP stated that rider and EMF were intended to allow DEP to recover $100,575,395 of DSM/EE expenses and incentives. This amount includes the estimated under-collection of $1,371,824 associated with test and prospective period activities during the period beginning August 1, 2013 and ending July 31, 2014 and an estimated $99,203,571 for expenses and incentives to be incurred during the rate period from December 1, 2014 through November 30, 2015. DEP requested that the Commission approve the following annual billing factor adjustments (including the regulatory fee):

Residential:

DSM/EE Rate	0.396 ¢/kWh
DSM/EE EMF Rate	0.008 ¢/kWh
Total	0.404 ¢/kWh

General Service:

DSM/EE Rate	0.398 ¢/kWh
DSM/EE EMF Rate	0.001 ¢/kWh
Total	0.399 ¢/kWh

Lighting:

DSM/EE Rate	0.108 ¢/kWh
DSM/EE EMF Rate	(0.005) ¢/kWh
Total	0.103 ¢/kWh

The following parties intervened in the proceeding: the Public Staff, CUCA, CIGFURII and SACE.

On September 12, 2014, DEP filed a Motion for Additional Public Hearing and Public Notice of Revised Proposed Rates due to DEP's proposed rates for Residential and Lighting customers having increased, and those for General Service customers having decreased. DEP noted that the revised rates would produce a revenue increase of $32.3 million compared to the $30.9 million revenue increase originally proposed in its application.

The Commission held a public hearing for this matter on September 16, 2014. The Commission held another public hearing on October 1, 2014, as a result of the additional rate increase[25] requested by DEP on September 12, 2014.

On November 25, 2014, the Commission issued its Order in the docket. In that Order the Commission further determined that the total DSM/EE annual riders including the DSM/EE rate and the DSM/EE EMF (including the regulatory fee) approved by the Commission are:

Rate Class	Total DSM/EE Rider
Residential	0.426 ¢/kWh
General Service	0.359 ¢/kWh
Lighting	0.112 ¢/kWh

The Commission further ordered that DEP incorporate recommendations by the Public Staff related to future EM&V reports regarding DEP's lighting measures, spillover savings and the Company's REEB program. The Company was also ordered to discuss in the collaborative meetings, the program recommendations suggested by SACE in its witness's testimony. Finally, the Commission directed that the results of these discussions should be included in DEP's next rider proceeding.

3. DEP DSM/EE Cost Recovery Rider – Docket No. E-2, Sub 1070

On June 17, 2015, DEP filed an application and the associated testimony and exhibits of its witnesses for the approval of a DSM/EE rider to recover reasonable and prudent forecasted DSM/EE costs, including carrying costs, net lost revenues (NLR), program performance incentive (PPI) and an EMF. In addition, DEP asked for approval of a DSM/EE EMF rider and, pursuant to Commission Rule R8-69(b)(2), recovery through the DSM/EE EMF of its post-test-year costs, including carrying costs and incentives incurred up to 30 days prior to the hearing in this proceeding. DEP stated that the rider and EMF were intended to allow DEP to recover $160,159,297 of DSM and EE expenses, net lost revenues, and incentives and that this amount includes the estimated under-collection of $15,806,668 associated with test period activities during the period beginning August 1, 2014[26], and ending December 31, 2014, and an estimated $144,352,629 for

[25] In DEP's September 12, 2014 filing, rates for two customer classes increased. Pursuant to N.C.G.S. § 62-134, the Commission scheduled an additional public hearing after the publication of notice by the Company to insure customers have adequate notice of the Company's revised proposed rates.

[26] The test period is normally a 12-month period; however, to effectuate the transition from the Original Mechanism to the Revised Mechanism the test period for purposes of this proceeding is April 1, 2014, through December 31, 2014. As the test period DSM/EE costs and utility incentives for the months of April through July 2014 were already trued-up in the Company's 2014 DSM/EE Rider proceeding pursuant to Commission Rule R8-69(b)(2), the test period DSM/EE costs and utility incentives being trued

expenses and incentives to be incurred during the rate period from January 1, 2016, through December 31, 2016. DEP requested that the Commission approve the following total annual billing factor adjustments (including the regulatory fee):

Residential	0.622 ¢/kWh
General Service EE	0.553 ¢/kWh
General Service DSM	0.040 ¢/kWh
Lighting	0.115 ¢/kWh

The Commission scheduled a hearing on September 15, 2015. As of the due date of this report, the matter was still pending before the Commission.

up in this proceeding are only those for the months of August through December 2014.

SECTION 5: COST RECOVERY MECHANISMS

1. DNCP - Docket No. E-22, Sub 464

On September 29, 2014, DNCP filed a letter initiating a formal review of the Commission-approved Mechanism in this docket. DNCP was ordered to do so no later than October 1, 2014, by the Commission in the Commission's October 14, 2011 Order initially approving the Mechanism in this docket. The Commission issued an Order on October 3, 2014, requesting comments on the Mechanism. Only the Public Staff submitted comments on DNCP's Mechanism.

On May 7, 2015, the Commission issued its Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waiver (Order on Revised Mechanism). The Order on Revised Mechanism approved an updated Cost Recovery and Incentive Mechanism for Demand Side Management and Energy Efficiency Programs (Revised Mechanism). The Revised Mechanism was effective for projected DSM/EE costs and utility incentives on and after January 1, 2016, and for true-up of DSM/EE costs and utility incentives for the period beginning July 1, 2014, through December 31, 2014, and on a lagging calendar year basis thereafter. The Revised Mechanism replaced a similar Mechanism that had been in effect since 2011.

Notable changes to the revised Mechanism approved by the Commission include:

1) Transitioning to a lagging calendar year experience modification (EMF) test period in order to allow DNCP more time between the end of its test period (currently June 30 of the filing year) and the filing date of its annual cost recovery petition (filed approximately August 20 annually).

2) Allowing the projected program performance incentive to be set using a "reasonable and appropriate estimation accomplished by a simpler and conservative method" than existing practice.

3) Beginning in 2017, DNCP will switch from calculating a program performance incentive as contemplated under the existing Mechanism to calculating a portfolio-based performance incentive. DNCP and the Public Staff agreed to resume discussions prior to the 2017 DSM/EE rider proceeding to discuss the revisions to this Mechanism necessary to accomplish this transition.

The Order required that the Public Staff and DNCP initiate a limited review of performance incentive provisions of the Company's Mechanism, as agreed to in the Mechanism, and file on or before March 1, 2017, an updated performance incentive proposal (or separate proposals if agreement cannot be reached) for the Commission's review and approval. The Order further provided that the Public Staff will initiate a formal review of the Company's Mechanism no later than October 1, 2019, unless requested to do so earlier by any interested party.

2. <u>DEC - Docket No. E-7, Sub 1032</u>

On March 6, 2013, DEC filed an application for approval of a new DSM and EE cost recovery and incentive mechanism, as well as a portfolio of new and existing DSM and EE programs.

DEC's proposed cost recovery mechanism would allow DEC to recover:

(1) all reasonable and prudent costs incurred for the adoption and implementation of new DSM/EE programs;
(2) net lost revenues associated with a particular vintage of EE programs for a maximum of three years or the life of the measure; and
(3) a performance incentive with different earning tiers ranging from 0% to 15% after-tax return on program costs.

The incentive earning tiers would be based on the overall cost-effectiveness of the Company's DSM and EE portfolio. The portfolio's cost-effectiveness would be determined by applying the Utility Cost Test (UCT). The UCT score for the portfolio would be calculated at the end of the year by dividing the net present value of DEC's avoided costs achieved by actual program costs, not including EM&V costs. The UCT score would be used to determine the percentage of after-tax return up to a maximum of 15%. That percentage would be multiplied by the program costs to determine DEC's incentive.

The Company proposed to continue several practices previously approved by the Commission for the Save-a-Watt pilot. These included the recovery of NLR; procedures for large customers to opt in and out of participation; applicability of EM&V results; determination of found revenues; program flexibility guidelines; and the stakeholder collaborative. In addition, DEC planned to convene a collaborative to consider the effect that increased participant incentives would have on opt-outs, cost-effectiveness and free ridership. Further, DEC requested the addition of a one week opt-in period to take place each March for customers who had previously elected to opt out during the annual November/December enrollment period.

Similar to the Save-a-Watt approach, the proposed recovery mechanism would use a vintage year concept, and the Company planned four calendar year vintages during the new program.

The Company's proposed rider charge for the new portfolio for January 1, 2014, through December 31, 2014, was 0.3032 cents per kWh for residential customers. For non-residential customers, the amounts differed depending upon customer participation elections. DEC requested approval of Rider 5, to become effective January 1, 2014, which included amounts related to all four vintages of the Save-a-Watt pilot and year one of the new portfolio of DSM/EE programs calculated pursuant to its proposed new cost recovery mechanism.

The following organizations intervened in DEC's DSM/EE rider mechanism proceeding:

Carolina Utility Customers Association, Inc. (CUCA)
Environmental Defense Fund (EDF)
North Carolina Sustainable Energy Association (NCSEA)
North Carolina Waste Reduction Network (NC WARN)
Piedmont Natural Gas Co.
Public Service Company of North Carolina, Inc.
Public Staff
Southern Alliance for Clean Energy (SACE)

On August 19, 2013, DEC, EDF, Natural Resources Defense Council, NCSEA, the Public Staff, South Carolina Coastal Conservation League and SACE filed an agreement and stipulation of settlement. That settlement included the following provisions:

1. Approval of all the DSM/EE programs proposed by DEC. However, there would be no four-year sunset on the programs.
2. DEC would be entitled to recover all prudent and reasonable program costs.
3. DEC's incentive payments would be similar to the DEP and DNCP shared savings mechanisms. DEC would receive a program performance incentive (PPI) of 11.5% of the net savings achieved by its DSM and EE programs. In comparison, DEP's PPI percentages are 13% of EE savings and 8% of DSM savings.
4. In addition to the PPI, DEC would receive a $400,000 bonus for each year during 2014-2018 in which it achieved incremental energy savings of 1% of its prior year's system retail sales.
5. The terms of the incentive mechanism would be reviewed by the Commission every four years.
6. DEC would recover net lost revenues on terms essentially as now provided under Save-a-Watt.
7. The terms of the current Flexibility Guidelines and EM&V Agreement would continue in effect.
8. DEC would continue holding quarterly stakeholder collaborative meetings.

On August 20, 2013, the Commission held its evidentiary hearing in this matter. On October 29, 2013, the Commission issued its decision on the matter. In that Order the Commission found that the Stipulation and Mechanism was just and reasonable to all parties in light of the evidence presented and served the public interest as it strikes a fair balance between the interests of DEC and its customers. The Commission further found that the portfolio of DSM and EE programs filed by DEC was approved as filed, except: (a) the programs were approved without a specific term and (b) the Non-Residential $mart Saver® Custom Program and Non-Residential $mart Saver® Custom Energy Assessments Program should not exclude bottoming-cycle CHP or the waste heat recovery components of topping-cycle CHP. The Commission also ordered DEC to meet with NC WARN, the Public Staff and any other interested intervenor to discuss the proposals submitted by NC WARN regarding the alternatives to the Company's Multi-

Family EE Program and Income-Qualified EE and Weatherization Program, with the intent of developing a Community Enhanced Program and revisions to DEC's Multi-Family Program to present to the Collaborative for discussion and refinement.

Also in that order the Commission granted the following requested waivers to DEC: (a) waiver of Rule R8-69(d)(3) to (i) allow the Company more flexibility in implementing and managing the opt-out elections of individual commercial customers with annual energy usage of not less than 1,000,000 kWh and industrial customers from participating in either the Company's DSM programs or EE programs, or both in combination, as set forth in the Commission's Order Granting Waiver, in Part, and Denying Waiver, in Part (Sub 938 Waiver Order) issued on April 6, 2010, in Docket No. E-7, Sub 938, and (ii) allow the Company to implement its proposal for an additional election period in March; (b) waivers of Rules R8-69(a)(4) and R8-69(a)(5) as approved by the Commission in its June 3, 2010 Order on Motions for Reconsideration in Docket No. E-7, Sub 938 (Sub 938 Second Waiver Order), for the duration of the Mechanism, unless otherwise ordered by the Commission in the future; and (c) waiver of Rule R8-69(b)(6) to allow the compounding of interest pursuant to the methodology used for the calculation of the return allowed for over- and under-recovered amounts as provided for in Paragraph 47 of the Stipulation.

Finally, regarding the review of the Mechanism, the Commission ordered that unless requested to do so earlier by the Company, the Public Staff, or another interested party, the Commission shall initiate a formal review of the Commission-approved Mechanism not later than July 1, 2017.

3. DEP - Docket No. E-2, Sub 931

On June 10, 2014, DEP filed a petition requesting that the Commission review DEP's Cost Recovery and Incentive Mechanism for DSM and EE programs (Mechanism). This review was a requirement of an earlier Commission order in Docket No. E-2, Sub 1002.

In its petition, DEP noted that its Mechanism is working well and producing significant and meaningful DSM and EE results.

Several parties intervened and provided comments in this proceeding: the Public Staff; SACE, NRDC, and Walmart.

On October 29, 2014, DEP, SACE, NRDC and the Public Staff entered a Settlement Agreement on the Revised Mechanism.

On January 20, 2015, the Commission issued an Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waivers. In that Order, the Commission approved the Settlement Agreement, which was generally to be effective January 1, 2016 (Revised Mechanism). The Revised Mechanism allows DEP to recover all reasonable and prudent costs incurred and utility incentives earned for adopting and implementing new DSM and EE measures in accordance with N.C.G.S. § 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Revised Mechanism.

The Revised Mechanism contained the following items of note:

1. Waivers of the following Commission rules: a) waiver of Rule R8-69(d)(3) to (i) allow the Company to implement and manage the opt-out elections of individual commercial customer accounts with annual energy usage of not less than 1,000,000 kilowatt-hours (kWh), and any industrial customer accounts, not to participate in either the Company's DSM programs or its EE Granting Waiver, in Part, and Denying Waiver, in Part issued on April 6, 2010, in Docket No. E-7, Sub 938 for DEC; and (b) waivers of Rules R8-69(a)(4) and R8-69(a)(5) to change the test period and rate period for DEP's DSM/EE rider to align with the calendar year, for the duration of the Mechanism.
2. Beginning in DEP's 2015 DSM/EE rider proceeding, the rate period for the proposed DSM/EE Rider will be the calendar year. Also beginning in DEP's 2015 DSM/EE rider proceeding, the test period used in the development of the DSM/EE EMF Rider will be the calendar year.
3. Beginning with DEP's 2015 DSM/EE rider proceeding, the annual filing date of DEP's DSM/EE rider application, supporting testimony, and Exhibits will be no later than June 30 of each calendar year.
4. Allowed DEP to leverage common practices with DEC by adopting and incorporating the Flexibility Guidelines established for DEC in Docket No. E-7, Sub 831 and then again approved as a component of its new portfolio in Docket No. E-7, Sub 1032.
5. A provision that the Company and Public Staff shall study the issue of the appropriate avoided transmission and distribution (T&D) costs to be used in the Company's calculations of cost-effectiveness and, if any adjustment was determined to be appropriate, the proposed adjustment was to be filed in the Company's 2015 DSM/EE rider proceeding to be effective on a prospective basis for vintage (calendar) year 2016.
6. Modification of the amount of the pre-income-tax PPI initially to be recovered in a Vintage Year for the entire DSM/EE portfolio, excluding programs not eligible for a PPI, to 11.75% of the present value of the estimated net dollar savings associated with the portfolio installed in that Vintage Year, calculated by program using the UCT (and excluding low income programs).
7. That DEP be allowed the opportunity to earn an additional incentive of $400,000 in any year from 2016 through 2020 in which it achieved incremental energy savings of 1% of the prior year's DEP system retail electricity sales.
8. The adoption of protocols and application methodology for evaluation, measurement, and verification (EM&V) results that were established in the EM&V Agreement between DEC, the Public Staff and Southern Alliance for Clean Energy which was approved by the Commission in Docket No. E-7, Sub 979, and maintained as a component of DEC's new portfolio in Docket No. E-7, Sub 1032, which will allow DEC and DEP to consolidate some aspects of the EM&V process and potentially save costs.

9. Modified the Opt-Out such that Opt-out eligible customers that have received DSM/EE Program incentives will be subject to the applicable DSM/EE rider and DSM/EE EMF rider billings for a period of no less than 36 months.
10. Allow eligible non-residential customers to opt out of either or both of the DSM and EE categories of programs as well as opt back into either or both. If a customer receives program incentives from a Company DSM or EE programs, that customer must opt-in for a period of no less than 36 months. A customer receiving program incentives from a DSM program will be required to pay the DSM portion of the DSM/EE Rider for a period of not less than 36 months. A customer receiving program incentives from an EE Program will be required to pay the EE portion of the DSM/EE Rider for a period of not less than 36 months.

The Order also stated that the Public Staff should initiate a formal review of the Company's Mechanism not later than February 1, 2019, unless requested to do so earlier by the Commission, the Company, or another interested party. The order further noted that the Public Staff's review should specifically address whether the incentives in the Commission-approved Mechanism are producing significant DSM and EE results; whether the customer rate impacts from the DSM/EE rider are reasonable and appropriate; whether overall portfolio performance targets should be adopted; and any other relevant issues that may be identified during the review process.

APPENDIX A

Rule R8-60. INTEGRATED RESOURCE PLANNING AND FILINGS.

(a) Purpose. — The purpose of this rule is to implement the provisions of G.S. 62-2(3a) and G.S. 62-110.1 with respect to least cost integrated resource planning by the utilities in North Carolina.

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

(c) Integrated Resource Plan. — Each utility shall develop and keep current an integrated resource plan, which incorporates, at a minimum, the following:

(1) a 15-year forecast of native load requirements (including any off-system obligations approved for native load treatment by the Commission) and other system capacity or firm energy obligations extending through at least one summer or winter peak (other system obligations); supply-side (including owned/leased generation capacity and firm purchased power arrangements) and demand-side resources expected to satisfy those loads; and the reserve margin thus produced; and

(2) a comprehensive analysis of all resource options (supply- and demand-side) considered by the utility for satisfaction of native load requirements and other system obligations over the planning period, including those resources chosen by the utility to provide reliable electric utility service at least cost over the planning period.

Each utility shall include an assessment of demand-side management and energy efficiency in its integrated resource plan. G.S. 62-133.9(c). In addition, each utility's consideration of supply-side and demand-side resources, including alternative supply-side energy resources, and the provision of reliable electric utility service at least cost shall appropriately consider and incorporate the utility's obligation to comply with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). G.S. 62-133.8.

(d) Purchased Power. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity.

(e) Alternative Supply-Side Energy Resources. — As part of its integrated resource planning process, each utility shall assess on an on-going basis the potential benefits of reasonably available alternative supply-side energy resource options. Alternative supply-side energy resources include, but are not limited to, hydro, wind, geothermal, solar thermal, solar photovoltaic, municipal solid waste, fuel cells, and biomass.

(f) Demand-Side Management. — As part of its integrated resource planning process, each utility shall assess on an on-going basis programs to promote demand-side management, including costs, benefits, risks, uncertainties, reliability and customer acceptance, where appropriate. For purposes of this rule, demand-side management consists of demand response programs and energy efficiency and conservation programs.

(g) Evaluation of Resource Options. — As part of its integrated resource planning process, each utility shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system. The utility shall analyze potential resource options and combinations of resource options to serve its system needs, taking into account the sensitivity of its analysis to variations in future estimates of peak load, energy requirements, and other significant assumptions, including, but not limited to, the risks associated with wholesale markets, fuel costs, construction/implementation costs, transmission and distribution costs, and costs of complying with environmental regulation. Additionally, the utility's analysis should take into account, as applicable, system operations, environmental impacts, and other qualitative factors.

(h) Filings.

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

(2) By September 1 of each year in which a biennial report is not required to be filed, an annual report shall be filed with the Commission containing an updated 15-year forecast of the items described in subparagraph (c)(1), as well as significant amendments or revisions to the most recently filed biennial report, including amendments or revisions to the type and size of resources identified, as applicable.

(3) Each biennial and annual report filed shall be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports.

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

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

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

(1) Forecasts of Load, Supply-Side Resources, and Demand-Side Resources. — The forecasts filed by each utility as part of its biennial report shall include descriptions of the methods, models, and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWh) forecasts and the variables used in the models. In both the biennial and annual reports, the forecasts filed by each utility shall include, at a minimum, the following:

(i) The most recent ten-year history and a forecast of customers by each customer class, the most recent ten-year history and a forecast of energy sales (kWh) by each customer class;

(ii) A tabulation of the utility's forecast for at least a 15-year period, including peak loads for summer and winter seasons of each year, annual energy forecasts, reserve margins, and load duration curves, with and without projected supply- or demand-side resource additions. The tabulation shall also indicate the projected effects of demand response and energy efficiency programs and activities on the forecasted annual energy and peak loads on an annual basis for a 15-year period, and these effects also may be reported as an equivalent generation capacity impact; and

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

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

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

a. Type of fuel(s) used;

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

c. Location of each existing unit;

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

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

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

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

a. Type of fuel(s) used;

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

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

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

(iii) Non-Utility Generation. — Each utility shall provide a separate and updated list of all non-utility electric generating facilities in its service areas, including customer-owned and stand-by generating facilities. This list shall include the facility name, location, primary fuel type, and capacity (including its designation as base, intermediate, or peaking capacity). The utility shall also indicate which facilities are included in its total supply of resources. If any of this information is readily accessible in documents already filed with the Commission, the utility may incorporate by reference the document or documents in its report, so long as the utility provides the docket number and the date of filing.

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

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

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

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

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

(5) Transmission Facilities. — Each utility shall include a list of transmission lines and other associated facilities (161 kV or over) which are under construction or for which there are specific plans to be constructed during the planning horizon, including the capacity and voltage levels, location, and schedules for completion and operation. The utility shall also include a discussion of the adequacy of its transmission system (161 kV and above).

(6) Demand-Side Management. — Each utility shall provide the results of its overall assessment of existing and potential demand-side management programs, including a descriptive summary of each analysis performed or used by the utility in the assessment. The utility also shall provide general information on any changes to the methods and assumptions used in the assessment since its last biennial report.

(i) For demand-side programs available at the time of the report, the utility shall provide the following information for each resource: the type of resource (demand response or energy efficiency); the capacity and energy available in the program; number of customers enrolled in each program; the number of times the utility has called upon the resource; and, where applicable, the capacity reduction realized each time since the previous biennial report. The utility shall also list any demand-side resource it has discontinued since its previous biennial report and the reasons for that discontinuance.

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

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

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

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

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

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

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

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

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

(i) For purposes of this requirement, the term "smart" in smart grid means a system having the ability to receive, process, and send information and/or data – essentially establishing a two-way communication protocol. (ii) For purposes of this requirement, smart grid technologies that are implemented in a smart grid deployment plan may include those that:

a. utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility's distribution or transmission system;

b. optimize grid operations dynamically;

c. improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency;

d. provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; or e. provide customers with usage information or retail energy pricing information in order to allow them to interpret and adjust their energy consumption.

(iii) The information provided shall include:

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

b. A comparison to “gross” MW and MWh without installation of the described smart grid technology.

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

(j) Contents of Update Reports. — In addition to the information required by sections (h)(2)-(4) of this rule, each utility shall include in its update report data and tables that provide the following data for the planning horizon: (1) the information required by sections (i)(1) and (2) of this rule, including the utility’s load forecast adjusted for the impacts of any new energy efficiency programs, existing generating capacity with planned additions, uprates, derates, and retirements, planned purchase contracts, undesignated future resources identified by type of generation and MW rating, renewable capacity, demand-side management capacity, and any resource gap; (2) cumulative resource additions necessary to meet load obligation and reserve margins; and (3) projections of load, capacity, and reserves for both the summer and winter periods. A total system IRP may be filed in lieu of an update report for purposes of compliance with this section.

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

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

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

(NCUC Docket No. E-100, Sub 54, 12/8/88; NCUC Docket No. E-100, Sub 78A, 04/29/98; 08/11/98; NCUC Docket No. M-100, Sub 128, 10/27/99; NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Sub 126, 4/11/2012; NCUC Docket No. M-100, Sub 140, 12/03/13; NCUC Docket No.E-100, Sub 111, 7/20/2015; NCUC Docket No. E-100, Sub 126, 6/13/2016.)

R8-67 RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD (REPS)

(a) Definitions.

(1) The following terms shall be defined as provided in G.S. 62-133.8: "Combined heat and power system"; "demand-side management"; "electric power supplier"; "new renewable energy facility"; "renewable energy certificate"; "renewable energy facility"; "renewable energy resource"; and "incremental costs."

(2) For purposes of determining an electric power supplier's avoided costs, "avoided cost rates" mean an electric power supplier's most recently approved or established avoided cost rates in this state, as of the date the contract is executed, for purchases of electricity from qualifying facilities pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978. If the Commission has approved an avoided cost rate for the electric power supplier for the year when the contract is executed, applicable to contracts of the same nature and duration as the contract between the electric power supplier and the seller, that rate shall be used as the avoided cost. Therefore, for example, for a contract by an electric public utility with a term of 15 years, the avoided cost rate applicable to that contract would be the comparable, Commission-approved, 15-year, long-term, levelized rate in effect at the time the contract was executed. In all other cases, the avoided cost shall be a good faith estimate of the electric power supplier's avoided cost, levelized over the duration of the contract, determined as of the date the contract is executed, taking into consideration the avoided cost rates then in effect as established by the Commission. In any event, when found by the Commission to be appropriate and in the public interest, a good faith estimate of an electric public utility's avoided cost, levelized over the duration of the contract, determined as of the date the contract is executed, may be used in a particular REPS cost recovery proceeding. Determinations of avoided costs, including estimates thereof, shall be subject to continuing Commission oversight and, if necessary, modification should circumstances so require.

(3) "Energy efficiency measure" means an equipment, physical, or program change that when implemented results in less use of energy to perform the same function or provide the same level of service. "Energy efficiency measure" does not include demand-side management. It includes energy produced from a combined heat and power system that uses nonrenewable resources to the extent the system:

(i) Uses waste heat to produce electricity or useful, measurable thermal or mechanical energy at a retail electric customer's facility; and

(ii) Results in less energy used to perform the same function or provide the same level of service at a retail electric customer's facility.

(4) "Year-end number of customer accounts" means the number of accounts within each customer class as of December 31 for a given calendar year determined in a manner approved by the Commission pursuant to subsection (c)(4) or determined in the same manner as that information is reported to the

Energy Information Administration, United States Department of Energy, for annual electric sales and revenue reporting.

(5) "Utility compliance aggregator" is an organization that assists an electric power supplier in demonstrating its compliance with REPS. Such demonstration may include, among other things, filing REPS compliance plans or reports and participating in NC-RETS on behalf of the electric power supplier or a group of electric power suppliers.

(b) REPS compliance plan.

(1) Each year, beginning in 2008, each electric power supplier or its designated utility compliance aggregator shall file with the Commission the electric power supplier's plan for complying with G.S. 62-133.8(b), (c), (d), (e) and (f). The plan shall cover the calendar year in which the plan is filed and the immediately subsequent two calendar years. At a minimum, the plan shall include the following information:

(i) a specific description of the electric power supplier's planned actions to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) for each year;

(ii) a list of executed contracts to purchase renewable energy certificates (whether or not bundled with electric power), including type of renewable energy resource, expected MWh, and contract duration;

(iii) a list of those planned or implemented energy efficiency and demand side management measures that the electric power supplier plans to use toward REPS compliance, including a brief description of each measure, its projected impacts, and a measurement and verification plan if such plan has not otherwise been filed with the Commission;

(iv) the projected North Carolina retail sales and year-end number of customer accounts by customer class for each year;

(v) the current and projected avoided cost rates for each year;

(vi) the projected total and incremental costs anticipated to implement the compliance plan for each year;

(vii) a comparison of projected costs to the annual cost caps for each year;

(viii) for electric public utilities, an estimate of the amount of the REPS rider and the impact on the cost of fuel and fuel-related costs rider necessary to fully recover the projected costs; and

(ix) to the extent not already filed with the Commission, the electric power supplier shall, on or before September 1 of each year, file a renewable energy facility registration statement pursuant to Rule R8-66 for any facility it owns and upon which it is relying as a source of power or RECs in its REPS compliance plan.

(2) Each electric power supplier shall file its REPS compliance plan with the Commission on or before September 1 of each year.

(3) Any electric power supplier subject to Rule R8-60 shall file its REPS compliance plan as part of its integrated resource plan filing, and the REPS

compliance plan will be reviewed and approved pursuant to Rule R8-60. Approval of the REPS compliance plan as part of the integrated resource plan shall not constitute an approval of the recovery of costs associated with REPS compliance or a determination that the electric power supplier has complied with G.S. 62 133.8(b), (c), (d), (e), and (f).

(4) An REPS compliance plan filed by an electric power supplier not subject to Rule R8-60 shall be for information only.

(c) REPS compliance report.

(1) Each year, beginning in 2009, each electric power supplier or its designated utility compliance aggregator shall file with the Commission a report describing the electric power supplier's compliance with the requirements of G.S. 62-133.8(b), (c), (d), (e) and (f) during the previous calendar year. The report shall include all of the following information, including supporting documentation:

(i) the sources, amounts, and costs of renewable energy certificates, by source, used to comply with G.S. 62-133.8(b), (c), (d), (e) and (f). Renewable energy certificates for energy efficiency may be based on estimates of reduced energy consumption through the implementation of energy efficiency measures, to the extent approved by the Commission;

(ii) the actual North Carolina retail sales and year-end number of customer accounts by customer class;

(iii) the current avoided cost rates and the avoided cost rates applicable to energy received pursuant to long-term power purchase agreements;

(iv) the actual total and incremental costs incurred during the calendar year to comply with G.S. 62-133.8(b), (c), (d), (e) and (f);

(v) a comparison of the actual incremental costs incurred during the calendar year to the per-account annual charges (in G.S. 62-133.8(g)(4)) applied to its total number of customer accounts as of December 31 of the previous calendar year;

(vi) the status of compliance with the requirements of G.S. 62-133.8(b), (c), (d), (e) and (f);

(vii) the identification of any renewable energy certificates or energy savings to be carried forward pursuant to G.S. 62-133.8(b)(2)f or (c)(2)f;

(viii) the dates and amounts of all payments made for renewable energy certificates; and

(ix) for electric membership corporations and municipal electric suppliers, reduced energy consumption achieved in each year after January 1, 2008, through the implementation of energy efficiency or demand-side management programs, along with the results of each program's measurement and verification plan, or other documentation supporting an estimate of the program's energy reductions achieved in the previous year pending implementation of a measurement and verification plan. Supporting documentation shall be retained and made available for audit.

(2) Each electric public utility shall file its annual REPS compliance report , together with direct testimony and exhibits of expert witnesses, on the same date that it files (1) its cost recovery request under Rule R8-67(e), and (2) the information required by Rule R8-55. The Commission shall consider each electric public utility's REPS compliance report at the hearing provided for in subsection (e) of this rule and shall determine whether the electric public utility has complied with G.S. 62-133.8(b), (d), (e) and (f). Public notice and deadlines for intervention and filing of additional direct and rebuttal testimony and exhibits shall be as provided for in subsection (e) of this rule.

(3) Each electric membership corporation and municipal electric supplier or their designated utility compliance aggregator shall file a verified REPS compliance report on or before September 1 of each year. The Commission may issue an order scheduling a hearing to consider the REPS compliance report filed by each electric membership corporation or municipal electric supplier, requiring public notice, and establishing deadlines for intervention and the filing of direct and rebuttal testimony and exhibits.

(4) In each electric power supplier's initial REPS compliance report, the electric power supplier shall propose a methodology for determining its cap on incremental costs incurred to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) and fund research as provided in G.S. 62-133.8(h)(1), including a determination of year-end number of customer accounts. The proposed methodology may be specific to each electric power supplier, shall be based upon a fair and reasonable allocation of costs, and shall be consistent with G.S. 62-133.8(h). The electric power supplier may propose a different methodology that meets the above requirements in a subsequent REPS compliance report filing. For electric public utilities, this methodology shall also be used for assessing the per-account charges pursuant to G.S. 62-133.8(h)(5).

(5) In any year, an electric power supplier or other interested party may petition the Commission to modify or delay the provisions of G.S. 62-133.8(b), (c), (d), (e) and (f), in whole or in part. The Commission may grant such petition upon a finding that it is in the public interest to do so. If an electric power supplier is the petitioner, it shall demonstrate that it has made a reasonable effort to meet the requirements of such provisions. Retroactive modification or delay of the provisions of G.S. 62-133.8(b), (c), (d), (e) or (f) shall not be permitted. The Commission shall allow a modification or delay only with respect to the electric power supplier or group of electric power suppliers for which a need for a modification or delay has been demonstrated.

(6) A group of electric power suppliers may aggregate their REPS obligations and compliance efforts provided that all suppliers in the group are subject to the same REPS obligations and compliance methods as stated in either G.S. 133.8(b) or (c). If such a group of electric power suppliers fails to meet its REPS obligations, the Commission shall find and conclude that each supplier in the group, individually, has failed to meet its REPS obligations.

(d) Renewable energy certificates.

(1) Renewable energy certificates (whether or not bundled with electric power) claimed by an electric power supplier to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) must have been earned after January 1, 2008; must have been purchased by the electric power supplier within three years of the date they were earned; shall be retired when used for compliance; and shall not be used for any other purpose. A renewable energy certificate may be used to comply with G.S. 62-133.8(b), (c), (d), (e) and (f) in the year in which it is acquired or obtained by an electric power supplier or in any subsequent year; provided, however, that an electric public utility must use a renewable energy certificate to comply with G.S. 62-133.8(b), (d), (e) and (f) within seven years of cost recovery pursuant to subsection (e)(10) of this Rule.

(2) For any facility that uses both renewable energy resources and nonrenewable energy resources to produce energy, the facility shall earn renewable energy certificates based only upon the energy derived from renewable energy resources in proportion to the relative energy content of the fuels used.

(3) Renewable energy certificates earned by a renewable energy facility after the date the facility's registration is revoked by the Commission shall not be used to comply with G.S. 62-133.8(b), (c), (d), (e) and (f).

(4) Renewable energy certificates must be issued by, or imported into, the renewable energy certificate tracking system established in Rule R8-67(h) in order to be eligible RECs under G.S. 62-133.8.

(e) Cost recovery.

(1) For each electric public utility, the Commission shall schedule an annual public hearing pursuant to G.S. 62-133.8(h) to review the costs incurred by the electric public utility to comply with G.S. 62-133.8(b), (d), (e) and (f). The annual rider hearing for each electric public utility will be scheduled as soon as practicable after the hearing held by the Commission for the electric public utility under Rule R8-55.

(2) The Commission shall permit each electric public utility to charge an increment or decrement as a rider to its rates to recover in a timely manner the reasonable incremental costs prudently incurred to comply with G.S. 62-133.8(b), (d), (e) and (f). The cost of an unbundled renewable energy certificate, to the extent that it is reasonable and prudently incurred, is an incremental cost and has no avoided cost component.

(3) Unless otherwise ordered by the Commission, the test period for each electric public utility shall be the same as its test period for purposes of Rule R8-55.

(4) Rates set pursuant to this section shall be recovered during a fixed cost recovery period that shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55.

(5) The incremental costs will be further modified through the use of an REPS experience modification factor (REPS EMF) rider. The REPS EMF rider will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect. Upon request of the electric public utility, the Commission shall also incorporate in this determination the experienced over-recovery or under-recovery of the incremental costs up to thirty (30) days prior to the date of the hearing, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual REPS cost recovery hearing.

(6) The REPS EMF rider will remain in effect for a fixed 12-month period following establishment and will carry through as a rider to rates established in any intervening general rate case proceedings.

(7) Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred incremental costs to be refunded to a utility's customers through operation of the REPS EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate.

(8) Each electric public utility shall follow deferred accounting with respect to the difference between actual reasonable and prudently-incurred incremental costs and related revenues realized under rates in effect.

(9) The incremental costs to be recovered by an electric public utility in any cost recovery period from its North Carolina retail customers to comply with G.S. 62-133.8(b), (d), (e), and (f) shall not exceed the per-account charges set forth in G.S. 62-133.8(h)(4) applied to the electric public utility's year-end number of customer accounts determined as of December 31 of the previous calendar year. These annual charges shall be collected through fixed monthly charges. Each electric public utility shall ensure that the incremental costs recovered under the REPS rider and REPS EMF rider during the cost recovery period, inclusive of gross receipts tax and the regulatory fee, from any given customer account do not exceed the applicable per-account charges set forth in G.S. 62-133.8(h)(4).

(10) Incremental costs incurred during a calendar year toward a current or future year's REPS obligation may be recovered by an electric public utility in any 12-month recovery period up to and including the 12-month recovery period in which the RECs associated with any incremental costs are retired toward the prior year's REPS obligation, as long as the electric public utility's charges to customers do not exceed, in any 12-month period, the per-account annual charges provided in G.S. 62-133.8(h)(4). A renewable energy certificate must be used for compliance and retired within seven years of the year in which the electric public utility recovers the related costs from customers. An electric public utility shall refund to customers with interest the costs for renewable energy certificates that are not used for compliance within seven years.

(11) Each electric public utility, at a minimum, shall submit to the Commission for purposes of investigation and hearing the information required for the REPS compliance report for the 12-month test period established in subsection

(3) normalized, as appropriate, consistent with Rule R8-55, accompanied by supporting workpapers and direct testimony and exhibits of expert witnesses, and any change in rates proposed by the electric public utility at the same time that it files the information required by Rule R8-55.

(12) The electric public utility shall publish a notice of the annual hearing for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least 30 days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-133.8(h) and setting forth the time and place of the hearing.

(13) Persons having an interest in said hearing may file a petition to intervene setting forth such interest at least 15 days prior to the date of the hearing. Petitions to intervene filed less than 15 days prior to the date of the hearing may be allowed in the discretion of the Commission for good cause shown.

(14) The Public Staff and other intervenors shall file direct testimony and exhibits of expert witnesses at least 15 days prior to the hearing date. If a petition to intervene is filed less than 15 days prior to the hearing date, it shall be accompanied by any direct testimony and exhibits of expert witnesses the intervenor intends to offer at the hearing.

(15) The electric public utility may file rebuttal testimony and exhibits of expert witnesses no later than 5 days prior to the hearing date.

(16) The burden of proof as to whether the costs were reasonable and prudently incurred shall be on the electric public utility.

(f) Contracts with owners of renewable energy facilities.

(1) The terms of any contract entered into between an electric power supplier and a new solar electric facility or new metered solar thermal energy facility shall be of sufficient length to stimulate development of solar energy.

(2) Each electric power supplier shall include appropriate language in all agreements for the purchase of renewable energy certificates (whether or not bundled with electric power) prohibiting the seller from remarketing the renewable energy certificates being purchased by the electric power supplier.

(g) Metering of renewable energy facilities.

(1) Except as provided below, for the purpose of receiving renewable energy certificate issuance in NC-RETS, the electric power generated by a renewable energy facility shall be measured by an electric meter supplied by and read by an electric power supplier. Facilities whose renewable energy certificates are issued in a tracking system other than NC-RETS shall be subject to the requirements of the applicable state commission and/or tracking system.

(2) The electric power generated by an inverter-based solar photovoltaic (PV) system with a nameplate capacity of 10 kW or less may be estimated using generally accepted analytical tools.

(3) The electric power generated by a renewable energy facility interconnected on the customer's side of the utility meter at a customer's location

may be measured by (1) an ANSI-certified electric meter not provided by an electric power supplier provided that the owner of the meter complies with the meter testing requirements of Rule R8-13, or (2) another industry-accepted, auditable and accurate metering, controls, and verification system. The data provided by such meter or system may be read and self-reported by the owner of the renewable energy facility, subject to audit by the Public Staff. The owner of the meter shall retain for audit for 10 years the energy output data.

(4) Thermal energy produced by a combined heat and power system or solar thermal energy facility shall be the thermal energy recovered and used for useful purposes other than electric power production. The useful thermal energy may be measured by meter, or if that is not practicable, by other industry-accepted means that show what measurable amount of useful thermal energy the system or facility is designed and operated to produce and use. Renewable energy certificates shall be earned based on one certificate for every 3,412,000 British thermal units (Btu) of useful thermal energy produced. Meter devices, if used, shall be located so as to measure the actual thermal energy consumed by the load served by the facility. Thermal energy output that is used as station power or to process the facility's fuel is not eligible for RECs. Thermal energy production data, whether metered or estimated, shall be retained for audit for 10 years.

(h) North Carolina Renewable Energy Certificate Tracking System (NC-RETS)

(1) Definitions

(i) "Balancing area operator" means an electric power supplier that has the responsibility to act as the balancing authority for a portion of the regional transmission grid, including maintaining the load-to-generation balance, accounting for energy delivered into and exported out of the area, and supporting interconnection frequency in real time.

(ii) "Multi-fuel facility" means a renewable energy facility that produces energy using more than one fuel type, potentially relying on a fuel that does not qualify for REC issuance in North Carolina.

(iii) "Participant" means a person or organization that opens an account in NC-RETS.

(iv) "Qualifying thermal energy output" is the useful thermal energy: (1) that is made available to an industrial or commercial process (net of any heat contained in condensate return and/or makeup water); (2) that is used in a heating application (e.g., space heating, domestic hot water heating); or (3) that is used in a space cooling application (i.e., thermal energy used by an absorption chiller).

(2) A renewable energy certificate (REC) tracking system, to be known as NC-RETS, is established by the Commission. NC-RETS shall issue, track, transfer and retire RECs. It shall calculate each electric power supplier's REPS obligation and report each electric power supplier's REPS accomplishments, consistent with the compliance report filed under Rule R8-67(c). NC-RETS shall be administered by a third-party vendor selected by the Commission. Only RECs issued by or imported into NC-RETS are qualifying RECs under G.S. 62-133.8.

(3) Each electric power supplier shall be a participant in NC-RETS and shall provide data to NC-RETS to calculate its REPS obligation and to demonstrate its compliance with G.S. 62-133.8. An electric power supplier may select a utility compliance aggregator to participate in NC-RETS on its behalf and file REPS compliance plans and compliance reports, but the supplier shall nonetheless remain responsible for its own compliance. For reporting purposes, an electric power supplier or its utility compliance aggregator may aggregate the supplier's compliance obligations and accomplishments with those of other suppliers that are subject to the same obligations under G.S. 62-133.8.

(4) Each renewable energy facility or new renewable energy facility registered by the Commission under Rule R8-66 shall participate in NC-RETS in order to have RECs issued, or in another REC tracking system in order to have RECs issued and transferred into NC-RETS, but no facility's meter data for the same time period shall be used for simultaneous REC issuance in two such systems. Beginning June 1, 2011, renewable energy facilities registered in NC-RETS may only enter historic energy production data for REC issuance that goes back up to two years from the current date. Facilities that produce energy using one or more renewable energy resource(s) and another resource that does not qualify toward REPS compliance under G.S. 62-133.8 shall calculate on a monthly basis and provide to NC-RETS the percentage of energy output attributable to each fuel source. NC-RETS will issue RECs only for energy emanating from sources that qualify under G.S. 62-133.8.

(5) Each balancing area operator shall provide monthly electric generation production data to NC-RETS for renewable and new renewable energy facilities that are interconnected to the operator's electric transmission system. Such balancing area operator shall retain documentation verifying the production data for audit by the Public Staff.

(6) Each electric power supplier that has registered renewable energy facilities or new renewable energy facilities interconnected with its electric distribution system and that reads the electric generation production meters for those facilities shall provide monthly the facilities' energy output to NC-RETS, and shall retain for audit for 10 years that energy output data. Municipalities and electric membership corporations may elect to have the facilities' production data reported to NC-RETS and retained for audit by a utility compliance aggregator.

(7) A renewable energy facility or new renewable energy facility that produces thermal energy that qualifies for RECs shall report the facility's qualifying thermal energy output to NC-RETS at least every 12 months. A renewable energy facility or new renewable energy facility that reports its data pursuant to Rule R8-67(g)(3) shall report its energy output to NC-RETS at least every 12 months.

(8) The owner of an inverter-based solar photovoltaic system with a nameplate capacity of 10 kW or less may estimate its energy output using generally accepted analytical tools pursuant to Rule R8-67(g)(2). Such an owner, or its agent, of this kind of facility shall report the facility's energy output to NC-RETS at least every 12 months.

(9) All energy output and fuel data for multi-fuel facilities, including underlying documentation, calculations, and estimates, shall be retained for audit for at least ten years immediately following the provision of the output data to NC-RETS or another tracking system, as appropriate.

(10) Each electric power supplier that complies with G.S. 62-133.8 by implementing energy efficiency or demand-side management programs shall use NC-RETS to report the energy savings of those programs. Municipal power suppliers and electric membership corporations may elect to have their energy savings from their energy efficiency and demand-side management programs reported to NC-RETS by a utility compliance aggregator, and to have their reported savings consolidated with the reported savings from other municipal power suppliers or electric membership corporations if and as necessary to permit aggregate reporting through their utility compliance aggregator. Records regarding which electric power supplier achieved the energy efficiency and demand-side management, the programs that were used, and the year in which it was achieved, shall be retained for audit.

(11) All Commission-approved costs of developing and operating NC-RETS shall be allocated among all electric power suppliers based upon their respective share of the total megawatt-hours of retail electricity sales in North Carolina in the previous calendar year. Each electric power supplier, or its utility compliance aggregator, shall, within 60 days of NC-RETS beginning operations, and by June 1 of each subsequent year, enter its previous year's retail electricity sales into NC-RETS, which sales will be used by NC-RETS to calculate each electric power supplier's REPS obligations and NC-RETS charges. NC-RETS shall update its billings beginning each July based on retail sales data for the previous calendar year. Such NC-RETS charges shall be deemed to be costs that are reasonable, prudent, incremental, and eligible for recovery through each electric public utility's annual rider established pursuant to G.S. 62-133.8(h).

(12) Each account holder in NC-RETS shall pay the NC-RETS administrator for service according to the following fee schedule:

(i) $0.01 for each REC export to an account residing in a different REC tracking system.

(ii) $0.01 for each REC retired for reasons other than compliance with G.S. 62-133.8.

(13) The Commission shall adopt NC-RETS Operating Procedures. The Commission shall establish an NC-RETS Stakeholder Group that shall meet from time to time and which may recommend changes to the NC-RETS Operating Procedures and NC-RETS.

(14) All data retention requirements of this Rule R8-67(h) may be accomplished via retention of electronic documents.

(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Subs 113 & 121, 1/31/11; NCUC Docket No. E-43, Sub 6, E-100, Sub 113, EC-33, Sub 58, EC-83, Sub 1, 5/14/2012.)

R8-68 INCENTIVE PROGRAMS FOR ELECTRIC PUBLIC UTILITIES AND ELECTRIC MEMBERSHIP CORPORATIONS, INCLUDING ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT PROGRAMS

(a) Purpose. — The purpose of this rule is to establish guidelines for the application of G.S. 62-140(c) and G.S. 62-133.9 to electric public utilities and electric membership corporations that are consistent with the directives of those statutes and consistent with the public policy of this State as set forth in G.S. 62-2.

(b) Definitions.

(1) Unless listed below, the definitions of all terms used in this rule shall be as set forth in Rule R8-67(a), or if not defined therein, then as set forth in G.S. 62-3, G.S. 62-133.8(a) and G.S. 62-133.9(a).

(2) “Consideration” means anything of economic value paid, given, or offered to any person by an electric public utility or electric membership corporation (regardless of the source of the “consideration’’) including, but not limited to: payments to manufacturers, builders, equipment dealers, contractors including HVAC contractors, electricians, plumbers, engineers, architects, and/or homeowners or owners of multiple housing units or commercial establishments; cash rebates or discounts on equipment/appliance sales, leases, or service installation; equipment/ appliances sold below fair market value or below their cost to the electric public utility or electric membership corporation; low interest loans, defined as loans at an interest rate lower than that available to the person to whom the proceeds of the loan are made available; studies on energy usage; model homes; and payment of trade show or advertising costs. Excepted from the definition of “consideration” are favors and promotional activities that are de minimis and nominal in value and that are not directed at influencing fuel choice decisions for specific applications or locations.

(3) “Costs” include, but are not limited to, all capital costs (including cost of capital and depreciation expenses), administrative costs, implementation costs, participation incentives, and operating costs. “Costs” does not include utility incentives.

(4) “Electric public utility” means a person, whether organized under the laws of this State or under the laws of any other state or country, now or hereafter owning or operating in this State equipment or facilities for producing, transporting, distributing, or furnishing electric service to or for the public for consumption. For purposes of this rule, “electric public utility” does not include electric membership corporations.

(5) “Net lost revenues” means the revenue losses, net of marginal costs avoided at the time of the lost kilowatt-hour sale(s), or in the case of purchased power, in the applicable billing period, incurred by the electric public utility as the result of a new demand-side management or energy efficiency measure. Net lost revenues shall also be net of any increases in revenues resulting from any activity by the electric public utility that causes a customer to increase demand or energy

consumption, whether or not that activity has been approved pursuant to this Rule R8-68.

(6) "New demand-side management or energy efficiency measure" means a demand-side management or energy efficiency measure that is adopted and implemented on or after January 1, 2007, including subsequent changes and modifications to any such measure. Cost recovery for "new demand-side management measures" and "new energy efficiency measures" is subject to G.S. 62-133.9.

(7) "Participation incentive" means any consideration associated with a new demand-side management or energy efficiency measure.

(8) "Program" or "measure" means any electric public utility action or planned action that involves the offering of consideration.

(9) "Utility incentives" means incentives as described in G.S. 62-133.9(d)(2)a-c.

(c) Filing for Approval.

(1) Application of Rule.

(i) Prior to an electric public utility or electric membership corporation implementing any measure or program, the purpose or effect of which is to directly or indirectly alter or influence the decision to use the electric public utility's or electric membership corporation's service for a particular end use or to directly or indirectly encourage the installation of equipment that uses the electric public utility's or electric membership corporation's service, or any new or modified demand-side management or energy efficiency measure, the electric public utility or the electric membership corporation shall obtain Commission approval, regardless of whether the measure or program is offered at the expense of the shareholders, ratepayers, or third-party.

(ii) This requirement shall also apply to measures and programs that are administered, promoted, or funded by the electric public utility's or electric membership corporation's subsidiaries, affiliates, or unregulated divisions or businesses if the electric public utility or electric membership corporation has control over the entity offering or is involved in the measure or program and an intent or effect of the measure or program is to adopt, secure, or increase the use of the electric public utility's public utility services.

(iii) Any application for approval by an electric public utility or electric membership corporation of a measure or program under this rule shall be made in a unique sub-docket of the electric public utility's or electric membership corporation's docket number.

(2) Filing Requirements. — Each application for the approval shall include:

(i) Cover Page. — The electric public utility or electric membership corporation shall attach to the front of an application a cover sheet generally describing:

a. the measure or program;

b. the consideration to be offered;

c. the anticipated total cost of the measure or program;

d. the source and amount of funding to be used; and

e. the proposed classes of persons to whom it will be offered.

(ii) Description. — The electric public utility or electric membership corporation shall provide a description of each measure and program, and include the following:

a. the program or measure's objective;

b. the duration of the program or measure;

c. the targeted sector and eligibility requirements;

d. examples of all communication materials to be used with the measure or program and the related cost for each program year;

e. the estimated number of participants;

f. the impact that each measure or program is expected to have on the electric public utility or electric membership corporation, its customer body as a whole, and its participating North Carolina customers; and

g. any other information the electric public utility or electric membership corporation believes is relevant to the application, including information on competition known by the electric public utility or the electric membership corporation.

(iii) Additionally, an electric public utility shall include or describe:

a. the measure's proposed marketing plan, including a description of market barriers and how the electric public utility intends to address them;

b. the total market potential and estimated market growth throughout the duration of the program;

c. the estimated summer and winter peak demand reduction by unit metric and in the aggregate by year;

d. the estimated energy reduction per appropriate unit metric and in the aggregate by year;

e. the estimated lost energy sales per appropriate unit metric and in the aggregate by year; and

f. the estimated load shape impacts.

(iv) Costs and Benefits. — The electric public utility or electric membership corporation shall provide the following information on the costs and benefits of each proposed measure or program: (a) the estimated total and per unit cost and benefit of the measure or program to the electric public utility or electric membership corporation, reported by type of benefit and expenditure (e.g., capital cost expenditures; administrative costs; operating costs; participation incentives, such as rebates and direct payments; and communications costs, and the costs of measurement and verification) and the planned accounting treatment for those costs and benefits; (b) the type, the maximum and minimum amount of participation incentives to be made to any party, and the reason for any participation incentives and other consideration and to whom they will be offered, including schedules listing participation incentives and other consideration to be offered; and (c) service limitations or conditions planned to be imposed on customers who do not participate in the measure. With respect to communications costs, the electric public utility or electric membership corporation shall provide detailed cost information on communications materials related to each proposed measure or program. Such costs shall be included in the Commission's consideration of the total cost of the measure or program and whether the total cost of the measure or program is reasonable in light of the benefits.

(v) Cost-Effectiveness Evaluation. — The electric public utility or electric membership corporation shall provide the economic justification for each proposed measure or program, including the results of all cost-effectiveness tests. Cost-effectiveness evaluations performed by the electric public utility or electric membership corporation should be based on direct or quantifiable costs and benefits and should include, at a minimum, an analysis of the Total Resource Cost Test, the Participant Test, the Utility Cost Test, and the Ratepayer Impact Measure Test. In addition, an electric public utility shall describe the methodology used to produce the impact estimates as well as, if appropriate, methodologies considered and rejected in the interim leading to the final model specification.

(vi) Commission Guidelines Regarding Incentive Programs. — The electric public utility or electric membership corporation shall provide the information necessary to comply with the Commission's Revised Guidelines for Resolution of Issues Regarding Incentive Programs, issued by Commission Order on March 27, 1996, in Docket No. M-100, Sub 124, set out as an Appendix to Chapter 8 of these rules.

(vii) Integrated Resource Plan. — When seeking approval of a new demand-side management or new energy efficiency measure, the electric public utility or electric membership corporation shall explain in detail how the measure is consistent with the electric public utility's or electric membership corporation's integrated resource plan filings pursuant to Rule R8-60.

(viii) Other. — Any other information the electric public utility or electric membership corporation believes relevant to the application, including information on competition known by the electric public utility or the electric membership corporation.

(3) Additional Filing Requirements. — In addition to the information listed in subsection (c)(2), an electric public utility filing for approval of a new or modified demand-side management or energy efficiency measure shall provide the following:

(i) Costs and Benefits. – The electric public utility shall describe:

a. any costs incurred or expected to be incurred in adopting and implementing a measure or program to be considered for recovery through the annual rider under G.S. 62-133.9;

b. estimated total costs to be avoided by the measure by appropriate capacity, energy and measure unit metric and in the aggregate by year;

c. estimated participation incentives by appropriate capacity, energy, and measure unit metric and in the aggregate by year;

d. how the electric public utility proposes to allocate the costs and benefits of the measure among the customer classes and jurisdictions it serves;

e. the capitalization period to allow the utility to recover all costs or those portions of the costs associated with a new program or measure to the extent that those costs are intended to produce future benefits as provided in G.S. 62-133.9(d)(1).

f. The electric public utility shall also include the estimated and known costs of measurement and verification activities pursuant to the Measurement and Verification Reporting Plan described in paragraph (ii).

(ii) Measurement and Verification Reporting Plan for New Demand-Side Management and Energy Efficiency Measures. — The electric public utility shall be responsible for the measurement and verification of energy and peak demand savings and may use the services of an independent third party for such purposes. The costs of implementing the measurement and verification process may be considered as operating costs for purposes of Commission Rule R8-69. In addition, the electric public utility shall:

a. describe the industry-accepted methods to be used to evaluate, measure, verify, and validate the energy and peak demand savings estimated in (2)(iii)c and d above;

b. provide a schedule for reporting the savings to the Commission;

c. describe the methodologies used to produce the impact estimates, as well as, if appropriate, the methodologies it considered and rejected in the interim leading to final model specification; and

d. identify any third party and include all of the costs of that third party, if the electric public utility plans to utilize an independent third party for purposes of measurement and verification.

(iii) Cost recovery mechanism. — The electric public utility shall describe the proposed method of cost recovery from its customers.

(iv) Tariffs or rates. — The electric public utility shall provide proposed tariffs or modifications to existing tariffs that will be required to implement each measure or program.

(v) Utility Incentives. — When seeking approval of new demand-side management and energy efficiency measures, the electric public utility shall indicate whether it will seek to recover any utility incentives, including, if appropriate, net lost revenues, in addition to its costs. If the electric public utility proposes recovery of utility incentives related to the proposed new demand-side management or energy efficiency measure, it shall describe the utility incentives it desires to recover and describe how its measurement and verification reporting plan will demonstrate the results achieved by the proposed measure. If the electric public utility proposes recovery of net lost revenues, it shall describe estimated net lost revenues by appropriate capacity, energy and measure unit metric and in the aggregate by year. If the electric public utility seeks recovery of utility incentives, including net lost revenues, apart from its recovery of its costs under G.S. 62-133.9, it shall file estimates of the utility incentives and the net lost revenues associated with the proposed measure for each year of the proposed recovery. If the electric public utility seeks only the recovery of net lost revenues apart from its recovery of combined costs and utility incentives, it shall file estimates of net lost revenues for each year of the proposed recovery period.

(d) Procedure.

(1) Automatic Tariff Suspension. – If an electric public utility files a proposed tariff or tariff amendment in connection with an application for approval of a measure or program, the tariff filing shall be automatically suspended pursuant to G.S. 62-134 pending investigation, review, and decision by the Commission.

(2) Service and Response. — The electric public utility or electric membership corporation filing for approval of a measure or program shall serve a copy of its filing on the Public Staff; the Attorney General; the natural gas utilities, electric public utilities, and electric membership corporations operating in the filing electric public utility's or electric membership corporation's certified territory; and any other party that has notified the electric public utility or electric membership corporation in writing that it wishes to be served with copies of all filings. If a party consents, the electric public utility or electric membership corporation may serve it with electronic copies of all filings. Those served, and others learning of the application, shall have thirty (30) days from the date of the filing in which to petition

for intervention pursuant to Rule R1-19, file a protest pursuant to Rule R1-6, or file comments on the proposed measure or program. In comments, any party may recommend approval or disapproval of the measure or program or identify any issue relative to the program application that it believes requires further investigation. The filing electric public utility or electric membership corporation shall have the opportunity to respond to the petitions, protests, or comments within ten (10) days of their filing. If any party raises an issue of material fact, the Commission shall set the matter for hearing. The Commission may determine the scope of this hearing.

(3) Notice and Schedule. — If the application is set for hearing, the Commission shall require notice, as it considers appropriate, and shall establish a procedural schedule for prefiled testimony and rebuttal testimony after a discovery period of at least 45 days. Where possible, the hearing shall be held within ninety (90) days from the application filing date.

(e) Scope of Review. — In determining whether to approve in whole or in part a new measure or program or changes to an existing measure or program, the Commission may consider any information it determines to be relevant, including any of the following issues:

(1) Whether the proposed measure or program is in the public interest and benefits the electric public utility's or electric membership corporation's overall customer body;

(2) Whether the proposed measure or program unreasonably discriminates among persons receiving or applying for the same kind and degree of service;

(3) Evidence of consideration or compensation paid by any competitor, regulated or unregulated, of the electric public utility or electric membership corporation to secure the installation or adoption of the use of such competitor's services;

(4) Whether the proposed measure or program promotes unfair or destructive competition or is inconsistent with the public policy of this State as set forth in G.S. 62-2 and G.S. 62-140; and

(5) The impact of the proposed measure or program on peak loads and load factors of the filing electric public utility or electric membership corporation, and whether it encourages energy efficiency.

(f) Cost Recovery for New Measures. —Approval of a program or measure under Commission Rule R8-68 does not constitute approval of rate recovery of the costs of the program or measure. With respect to new demand-side management and energy efficiency measures, the costs of those new measures, approved by application of this rule, that are found to be reasonable and prudently incurred shall be recovered through the annual rider described in G.S. 62-133.9 and Rule R8-69. The Commission may consider in the annual rider proceeding whether to approve the inclusion of any utility incentive pursuant to G.S. 62-133.9(d)(2)a-c. in the annual rider.

(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Subs 113 & 121, 1/31/11; NCUC Docket No. M-100, Sub 140, 12/03/13.)

R8-69 COST RECOVERY FOR DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY MEASURES OF ELECTRIC PUBLIC UTILITIES

(a) Definitions.

(1) Unless listed below, the definitions of all terms used in this rule shall be as set forth in Rules R8-67 and R8-68, or if not defined therein, then as set forth in G.S. 62-133.8(a) and G.S. 62-133.9(a).

(2) “DSM/EE rider” means a charge or rate established by the Commission annually pursuant to G.S. 62-133.9(d) to allow the electric public utility to recover all reasonable and prudent costs incurred in adopting and implementing new demand-side management and energy efficiency measures after August 20, 2007, as well as, if appropriate, utility incentives, including net lost revenues.

(3) “Large commercial customer” means 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.

(4) “Rate period” means the period during which the DSM/EE rider established under this rule will be in effect. For each electric public utility, this period will be the same as the period during which the rider established under Rule R8-55 is in effect.

(5) “Test period” shall be the same for each public utility as its test period for purposes of Rule R8-55, unless otherwise ordered by the Commission.

(b) Recovery of Costs.

(1) Each year the Commission shall conduct a proceeding for each electric public utility to establish an annual DSM/EE rider. The DSM/EE rider shall consist of a reasonable and appropriate estimate of the expenses expected to be incurred by the electric public utility, during the rate period, for the purpose of adopting and implementing new demand-side management and energy efficiency measures previously approved pursuant to Rule R8-68. The expenses will be further modified through the use of a DSM/EE experience modification factor (DSM/EE EMF) rider. The DSM/EE EMF rider will reflect the difference between the reasonable expenses prudently incurred by the electric public utility during the test period for that purpose and the revenues that were actually realized during the test period under the DSM/EE rider then in effect. Those expenses approved for recovery shall be allocated to the North Carolina retail jurisdiction consistent with the system benefits provided by the new demand-side management and energy efficiency measures and shall be assigned to customer classes in accordance with G.S. 62-133.9(e) and (f).

(2) Upon the request of the electric public utility, the Commission shall also incorporate the experienced over-recovery or under-recovery of costs up to thirty (30) days prior to the date of the hearing in its determination of the DSM/EE

EMF rider, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual DSM/EE rider hearing.

(3) Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred costs to be refunded to an electric public utility's customers through operation of the DSM/EE EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate. The beginning date for measurement of such interest shall be the effective date of the DSM/EE EMF rider in each annual proceeding, unless otherwise determined by the Commission.

(4) The burden of proof as to whether the costs were reasonably and prudently incurred shall be on the electric public utility.

(5) Any costs incurred for adopting and implementing measures that do not constitute new demand-side management or energy efficiency measures are ineligible for recovery through the annual rider established in G.S. 62-133.9.

(6) Except as provided in (c)(3) of this rule, each electric public utility may implement deferral accounting for costs considered for recovery through the annual rider. At the time the Commission approves a new demand-side management or energy efficiency measure under Rule R8-68, the electric public utility may defer costs of adopting and implementing the new measure in accordance with the Commission's approval order under Rule R8-68. Subject to the Commission's review, the electric public utility may begin deferring the costs of adopting and implementing new demand-side management or energy efficiency measures six (6) months prior to the filing of its application for approval under Rule R8-68, except that the Commission may consider earlier deferral of development costs in exceptional cases, where such deferral is necessary to develop an energy efficiency measure. Deferral accounting, however, for any administrative costs, general costs, or other costs not directly related to a new demand-side management or energy efficiency measure must be approved prior to deferral. The balance in the deferral account, net of deferred income taxes, may accrue a return at the net-of-tax rate of return approved in the electric public utility's most recent general rate proceeding. The return so calculated will be adjusted in any rider calculation to reflect necessary recoveries of income taxes. This return is not subject to compounding. The accrual of such return of on any under-recovered or over-recovered balance set in an annual proceeding for recovery or refund through a DSM/EE EMF rider shall cease as of the effective date of the DSM/EE EMF rider in that proceeding, unless otherwise determined by the Commission. However, deferral accounting of costs shall not affect the Commission's authority under this rule to determine whether the deferred costs may be recovered.

(c) Utility Incentives.

(1) With respect to a new demand-side management or energy efficiency measure previously approved under Rule R8-68, the electric public utility may, in its annual filing, apply for recovery of any utility incentives, including, if appropriate, net lost revenues, identified in its application for approval of the

measure. The Commission shall determine the appropriate ratemaking treatment for any such utility incentives.

(2) When requesting inclusion of a utility incentive in the annual rider, the electric public utility bears the burden of proving its calculations of those utility incentives and the justification for including them in the annual rider, either through its measurement and verification reporting plan or through other relevant evidence.

(3) An electric public utility shall not be permitted to implement deferral accounting or the accrual of a return for utility incentives unless the Commission approves an annual rider that provides for recovery of an integrated amount of costs and utility incentives. In that instance, the Commission shall determine the extent to which deferral accounting and the accrual of a return will be allowed.

(d) Special Provisions for Industrial or Large Commercial Customers.

(1) Pursuant to G.S. 62-133.9(f), any industrial customer or large commercial customer may notify its electric power supplier that: (i) it has implemented or, in accordance with stated, quantifiable goals, will implement alternative demand-side management or energy efficiency measures; and (ii) it elects not to participate in demand-side management or energy efficiency measures for which cost recovery is allowed under G.S. 62-133.9. Any such customer shall be exempt from any annual rider established pursuant to this rule after the date of notification.

(2) At the time the electric public utility petitions for the annual rider, it shall provide the Commission with a list of those industrial or large commercial customers that have opted out of participation in the new demand-side management or energy efficiency measures. The electric public utility shall also provide the Commission with a listing of industrial or large commercial customers that have elected to participate in new measures after having initially notified the electric public utility that it declined to participate.

(3) Any customer that opts out but subsequently elects to participate in a new demand-side management or energy efficiency measure or program loses the right to be exempt from payment of the rider for five years or the life of the measure or program, whichever is longer. For purposes of this subsection, “life of the measure or program” means the capitalization period approved by the Commission to allow the utility to recover all costs or those portions of the costs associated with a program or measure to the extent that those costs are intended to produce future benefits as provided in G.S. 62-133.9(d)(1).

(e) Annual Proceeding.

(1) For each electric public utility, the Commission shall schedule an annual rider hearing pursuant to G.S. 62-133.9(d) to review the costs incurred by the electric public utility in the adoption and implementation of new demand-side management and energy efficiency measures during the test period, the revenues realized during the test period through the operation of the annual rider, and the costs expected to be incurred during the rate period and shall establish annual DSM/EE and DSM/EE EMF riders to allow the electric public utility to recover all costs found by the Commission to be recoverable. The Commission may also

approve, if appropriate, the recovery of utility incentives, including net lost revenues, pursuant to G.S. 62-133.9(d)(2) in the rider.

(2) The annual rider hearing for each electric public utility will be scheduled as soon as practicable after the hearing held by the Commission for the electric public utility under Rule R8-55. Each electric public utility shall file its application for recovery of costs and appropriate utility incentives at the same time that it files the information required by Rule R8-55.

(3) The DSM/EE EMF rider will remain in effect for a fixed 12-month period following establishment and will continue as a rider to rates established in any intervening general rate case proceeding.

(f) Filing Requirements and Procedure.

(1) Each electric public utility shall submit to the Commission all of the following information and data in its application:

(i) Projected North Carolina retail monthly kWh sales for the rate period.

(ii) For each measure for which cost recovery is requested through the DSM/EE rider:

a. total expenses expected to be incurred during the rate period in the aggregate and broken down by type of expenditure, per appropriate capacity, energy and measure unit metric and the proposed jurisdictional allocation factors;

b. total costs that the utility does not expect to incur during the rate period as a direct result of the measure in the aggregate and broken down by type of cost, per appropriate capacity, energy and measure unit metric, and the proposed jurisdictional allocation factors, as well as any changes in the estimated future amounts since last filed with the Commission;

c. a description of the measurement and verification activities to be conducted during the rate period, including their estimated costs;

d. total expected summer and winter peak demand reduction per appropriate measure unit metric and in the aggregate;

e. total expected energy reduction in the aggregate and per appropriate measure unit metric.

(iii) For each measure for which cost recovery is requested through the DSM/EE EMF rider:

a. total expenses for the test period in the aggregate and broken down by type of expenditure, per appropriate capacity, energy and measure unit metric and the proposed jurisdictional allocation factors;

b. total costs that the utility did not incur for the test period as a direct result of the measure in the aggregate and broken down by type of cost, per appropriate capacity, energy and measure unit metric, and the proposed jurisdictional allocation factors, as well as any changes in the estimated future amounts since last filed with the Commission;

c. a description of, the results of, and the costs of all measurement and verification activities conducted in the test period;

d. total summer and winter peak demand reduction in the aggregate and per appropriate measure unit metric, as well as any changes in estimated future amounts since last filed with the Commission;

e. total energy reduction in the aggregate and per appropriate measure unit metric, as well as any changes in the estimated future amounts since last filed with the Commission;

f. a discussion of the findings and the results of the program or measure;

g. evaluations of event-based programs including the date, weather conditions, event trigger, number of customers notified and number of customers enrolled; and

h. a comparison of impact estimates presented in the measure application from the previous year, those used in reporting for previous measure years, and an explanation of significant differences in the impacts reported and those previously found or used.

(iv) For each measure for which recovery of utility incentives is requested, a detailed explanation of the method proposed for calculating those utility incentives, the actual calculation of the proposed utility incentives, and the proposed method of providing for their recovery and true-up through the annual rider. If recovery of net lost revenues is requested, the total net lost kWh sales and net lost revenues per appropriate capacity, energy, and program unit metric and in the aggregate for the test period, and the proposed jurisdictional allocation factors, as well as any changes in estimated future amounts since last filed with the Commission.

(v) Actual revenues produced by the DSM/EE rider and the DSM/EE EMF rider established by the Commission during the test period and for all available months immediately preceding the rate period.

(vi) The requested DSM/EE rider and DSM/EE EMF rider and the basis for their determination.

(vii) Projected North Carolina retail monthly kWh sales for the rate period for all industrial and large commercial accounts, in the aggregate, that are not assessed the rider charges as provided in this rule.

(viii) All workpapers supporting the calculations and adjustments described above.

(2) Each electric public utility shall file the information required under this rule, accompanied by workpapers and direct testimony and exhibits of expert

witnesses supporting the information filed in this proceeding, and any change in rates proposed by the electric public utility, by the date specified in subdivision (e)(2) of this rule. An electric public utility may request a rider lower than that to which its filed information suggests that it is entitled.

(3) The electric public utility shall publish a notice of the annual hearing for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least thirty (30) days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-133.9(d) and setting forth the time and the place of the hearing.

(4) Persons having an interest in any hearing may file a petition to intervene at least 15 days prior to the date of the hearing. Petitions to intervene filed less than 15 days prior to the date of the hearing may be allowed in the discretion of the Commission for good cause shown.

(5) The Public Staff and other intervenors shall file direct testimony and exhibits of expert witnesses at least 15 days prior to the hearing date. If a petition to intervene is filed less than 15 days prior to the hearing date, it shall be accompanied by any direct testimony and exhibits of expert witnesses the intervenor intends to offer at the hearing.

(6) The electric public utility may file rebuttal testimony and exhibits of expert witnesses no later than 5 days prior to the hearing date.

(NCUC Docket No. E-100, Sub 113, 2/29/08; NCUC Docket No. E-100, Sub 113, 3/13/08; NCUC Docket No. E-100, Subs 113 & 121, 1/31/11.)