STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Implement	)	ORDER ADOPTING
Session Law 2007-397	)	FINAL RULES

BY THE COMMISSION: On August 23, 2007, the Commission issued an Order Initiating Rulemaking Proceeding in this docket seeking comment from interested persons on rules to implement Session Law 2007-397 (Senate Bill 3). In addition, the Commission requested that the Public Staff of the North Carolina Utilities Commission (Public Staff), after considering the parties' initial filings, prepare and file proposed rules or rule revisions implementing Section 4 of Senate Bill 3.

Pursuant to the Commission's August 23, 2007 Order, comments were received on or before September 24, 2007, from 23 parties:

- Acciona Energy North America Corporation (Acciona);
- Appalachian Energy, LLC;
- Carolina Industrial Group for Fair Utility Rates I, II and III (CIGFUR);
- Carolina Utility Customers Association, Inc. (CUCA);
- CPV Renewable Energy Company, LLC (CPV);
- North Carolina Department of Environment and Natural Resources, Division of Water Resources (DENR);
- Virginia Electric and Power Company d/b/a Dominion North Carolina Power (Dominion);
- Duke Energy Carolinas, LLC (Duke);
- ElectriCities of North Carolina, Inc. (ElectriCities);
- Environmental Defense (ED);
- North Carolina Electric Membership Corporation (NCEMC);
- North Carolina Farm Bureau Federation, Inc. (NCFB);
- North Carolina Small Hydro Group (Small Hydro);
- North Carolina Sustainable Energy Association (NCSEA);
- North Carolina Wildlife Resources Commission (Wildlife Resources).
- Nucor Steel-Hertford, a division of Nucor Corporation (Nucor);
- Progress Energy Carolinas, Inc. (Progress);
- Southern Alliance for Clean Energy (SACE);
- Southern Environmental Law Center (SELC);
- Southern Energy Management (SEM);
- Solar Alliance;

- Sun Edison LLC (SunEdison); and
- Wal-Mart Stores East, LP (Wal-Mart).

In addition, comments were received from the United States Clean Heat and Power Association (CHPA), which filed a motion to submit comments as an interested party without seeking to intervene as a formal party. On November 6, 2007, the Commission received a letter from the Mayor of Chapel Hill.

Other parties that were allowed to intervene include:

- Bio-Energy Conversion, LLC (Bio-Energy);
- Domtar Paper Company, LLC (Domtar);
- EcoPlus, Inc. (EcoPlus);
- Elster Integrated Solutions (Elster);
- Fibrowatt, LLC (Fibrowatt);
- William H. Lee (Lee);
- North Carolina Waste Awareness and Reduction Network, Inc. (NC WARN);
- Piedmont Natural Gas Company, Inc. (Piedmont); and
- Public Service Company of North Carolina (PSNC).

In addition, Roy Cooper, Attorney General, filed his notice of intervention. The intervention and participation of the Public Staff is recognized in accordance with applicable law. The petition to intervene filed by EnergyUnited Electric Membership Corporation was denied.

On October 26, 2007, after reviewing the initial filings of the parties, the Commission issued an Order Issuing Proposed Rules for Comment. Clean and black-lined versions of the proposed rules compared to the Commission's current rules were attached to the Order as Appendices A and B.

Pursuant to the Commission's October 26, 2007 Order, initial comments were received on or before November 14, 2007, from Bio-Energy, CIGFUR, CPV, CUCA, Dominion, Duke, ED, ElectriCities, NC WARN, NCEMC, NCFB, NCSEA, Nucor, Piedmont, Progress, SACE, SELC, Solar Alliance, SunEdison, Wal-Mart, Wildlife Resources, the Attorney General and the Public Staff. In addition, comments were received from Dr. John Neufeld, Professor of Economics, UNC Greensboro. Reply comments were received on or before December 17, 2007, from CPV, CUCA, CIGFUR, Dominion, Duke, ED, ElectriCities, NC WARN, NCEMC, NCSEA, Nucor, Piedmont, Progress, PSNC, SACE, SELC, Small Hydro, Solar Alliance, SunEdison, Wal-Mart, the Attorney General and the Public Staff. In addition, comments were received from CHPA and the North Carolina Public Interest Research Group and Education Fund (NCPIRG). Supplemental comments were filed after December 17, 2007, by NCSEA, Duke and Progress.

As a preliminary matter, the Commission stated in its October 26, 2007 Order that, despite the fact that certain choices necessarily had to be made in order to propose rules for comment, it had not made a final decision with regard to any substantive issue in this proceeding. In numerous filings since the issuance of that Order, Duke argued that adoption of the proposed rules "will have prejudged the merits of" its Save-a-Watt proposal in Docket No. E-7, Sub 831. In a separate letter filed on December 17, 2007, Duke "reiterate[d] its disappointment" with the proposed rules and complained that the Commission had "effectively foreclosed the opportunity for consideration of" Duke's proposal. As discussed below with respect to specific issues, it was not and is not the Commission's intent in adopting rules to implement Senate Bill 3 to prejudge the merits of Duke's Save-a-Watt proposal, except as it might be contrary to the new law, or to limit the opportunity for any other party to raise concerns or challenge Duke's proposal in subsequent proceedings. In its August 31, 2007 Order in Docket Nos. E-7, Subs 828, 829 and 831 and E-100, Sub 112, the Commission stated that it "will hear and decide the merits of Duke's Save-a-Watt application after completion of" this rulemaking. With the issuance of this Order and the adoption of final rules to implement Senate Bill 3, the Commission is now prepared to address Duke's proposal in a separate proceeding. The Commission reiterates that it has not prejudged any aspect of Duke's proposal and could not do so consistent with the Code of Judicial Conduct. Duke's suggestion to the contrary is simply erroneous.

The Commission has carefully considered all of the comments filed in this docket in adopting final rules to implement Senate Bill 3. The positions of the parties and the Commission's conclusions with respect to the most significant issues raised in the comments are set forth below. Proposals not specifically discussed below have been considered and decided as reflected in the final rules. Appendix A to this Order is a clean version of the final rules.[1] Appendix B is a black-lined comparison of the final rules to the proposed rules attached to the Commission's October 26, 2007 Order.

ISSUE 1. Request for public hearings

NC WARN requested, in light of the substantial public interest shown in the legislative debate on Senate Bill 3, that the Commission hold a public hearing with regard to the rules implementing the statute. NC WARN noted that the Commission often has public hearings as part of any number of types of dockets, and a public hearing provides a clear means for interested members of the public to provide their input without the burden of intervening. No party commented on NC WARN's request.

While hearings are often held in matters before the Commission, the Commission concludes that hearings are not necessary or appropriate in this proceeding. The Commission has, however, as NC WARN suggested, sought and received substantial

[1] The Commission determined as it was issuing this Order that the General Assembly had codified Section 2(a) of Senate Bill 3 as G.S. 62-133.8 and Section 4(a) as G.S. 62-133.9. To reduce the potential for confusion, the Commission will reference in this Order and in the attached rules, as did the parties in their comments, Section 2(a) of Senate Bill 3 as G.S. 62-133.7 and Section 4(a) as G.S. 62-133.8. The Commission will amend by further order the rules adopted herein to correct the statutory references in the rules.

comment from (MULTIPLE PARTIES REPRESENTING) the public with regard to the rules proposed to be adopted to implement Senate Bill 3. Therefore, the Commission concludes that the public has had an adequate opportunity to participate in this proceeding and to inform the Commission of its views, that all of the important issues in this docket have been fully vetted, and that public hearings as suggested by NC WARN would only delay the adoption of rules without providing new material information to the Commission for use in reaching its decision. It should be noted that the application and implementation of the rules adopted herein will occur in specific proceedings in which members of the public will have a meaningful opportunity to participate.

RULE R8-52

ISSUE 2. Information required to be included in Monthly Fuel Reports

Rule R8-52(a) specifies the information that electric public utilities must file in their Monthly Fuel Repots.

The Public Staff proposed to revise Rule R8-52(a) to provide greater specificity with respect to the contents of the Monthly Fuel Reports in keeping with G.S. 62-133.2(a1) and (a3) and to include information regarding costs to comply with the Swine Farm Methane Capture Pilot Program established in Section 4 of Session Law 2007-523.

No other revisions to Rule R8-52 have been proposed in this proceeding, and no party opposed the Public Staff's proposed revisions to Rule R8-52.

The Commission, therefore, concludes that Rule R8-52 should be revised as proposed by the Public Staff.

RULE R8-55

ISSUE 3. Dates for annual fuel hearings and filing schedules

Proposed changes to sections (b), (f), (h), (i) and (j) of Rules R8-55 would modify the schedule for annual hearings to review changes in the cost of fuel and fuel-related costs.

Duke commented that the proposed amendments "allocate all of the additional time [within which the Commission must rule on a fuel charge adjustment application] to the intervenors and the Commission." Duke also expressed concern that the proposed hearing date of the third Tuesday of June is burdensome given the schedule of its fuel cost adjustment proceeding in South Carolina. Duke proposed amendments to proposed Rule R8-55 to provide that its annual hearing will be scheduled for the first Tuesday of June and that its application will be filed 90 days, rather than 105 days, prior to the hearing. Duke proposed that interventions and intervenor testimony be filed 30 days, rather than 15 days, prior to the hearing to allow the utilities and other parties notice of the identity of the parties that may participate and issues that may be raised at the hearing. Progress also proposed that interventions and intervenor testimony be filed 30 days prior to the hearing, but proposed that rebuttal testimony be filed 15 days, rather than 5 days, prior to the hearing.

Dominion expressed concern about the effect of the proposed schedule on the effective date of its rate change for changes in the cost of fuel and fuel-related costs and proposed that its hearing date be returned to the second Tuesday of November. Dominion also proposed that the utility be required to file its application 75 days prior to the hearing and that rates be effective 120 days after the application is filed.

In its reply comments, the Public Staff asserted that Senate Bill 3 extended the time within which the Commission must issue an order after an application is filed under G.S. 62-133.2 from 120 days to 180 days at the request of the Commission and the Public Staff. The intent was to give the Public Staff additional time to investigate, and the Commission additional time to issue a decision, in a proceeding made significantly more complex by the addition of “fuel-related costs” to the statute pursuant to Senate Bill 3. The simplest way to accomplish this objective is to extend the hearing dates and effective dates of the rate changes while retaining the current test periods and deadlines for filing applications. However, the Public Staff recognized the concerns of the utilities and did not object to some modifications to the proposed schedule to accommodate them. The Public Staff recommended that proposed Rule R8-55(b) be changed to provide that the annual hearing for Duke will be scheduled for the first Tuesday of June and that the annual hearing for Dominion will be scheduled for the second Tuesday of November, as it is under the current rule. The Public Staff further recommended that proposed Rule R8-55(f) be changed to provide that the applications and testimony will be filed by Duke and Progress at least 90 days prior to the hearing and by Dominion at least 75 days prior to the hearing, but that the filing of intervenor testimony will be left at 15 days prior to the hearing. This will give the Public Staff 75 days in which to investigate the applications of Duke and Progress and 60 days in which to investigate the less complex application of Dominion, which the Public Staff hopes will be adequate. The Public Staff further noted that, since filing its comments, Duke has suggested that its rider hearing under proposed Rule R8-69 be scheduled for the first Tuesday of May instead of as soon as practicable after the hearing under Rule R8-55. The Public Staff does not believe that a hearing 60 days after the filing will allow sufficient time for investigation and therefore opposed this change.

CUCA opposed the proposals by the utilities for the Commission to alter the timing relating to fuel and REPS review proceedings. According to CUCA, the utilities’ proposals would unreasonably shorten the period for discovery in these proceedings. CUCA asserted that the timeline set forth in the Commission’s proposed rules is reasonable, and, for that reason, CUCA stated that it is opposed to all of the utilities’ proposals on this issue.

In its initial comments, Nucor proposed that Rule R8-55(j) be revised to allow the Public Staff and other intervenors an opportunity to file surrebuttal testimony. In its reply comments, Nucor asserted that the new schedule for Dominion’s annual fuel proceedings contained in the Commission’s proposed rules should be adopted. Nucor stated that the existing schedule for fuel proceedings is already tight prior to the Senate Bill 3 amendments, even without the extra DSM/EE and REPS filing requirements. With these new elements added to the mix, it is even more important that additional time be built into the schedule. The schedule contained in the Commission's proposed rule should be adopted.

Duke, Progress and Dominion opposed Nucor's proposed change regarding surrebuttal testimony, asserting that Nucor's proposal is inconsistent with the standard evidentiary requirement that the party with the burden of proof has the right to open and close with regard to the presentation of evidence.

The Commission agrees with the hearing dates and filing schedules recommended by the Public Staff and will, therefore, approve, with minor modification, the Public Staff's proposed revisions to Rule R8-55 as discussed above. The revised dates for the annual hearings and filing schedules specified in Rule R8-55(b) and (f) will be approved with one caveat; the Commission hereby reserves the right to revisit the hearing dates and filing schedules approved for Duke, Progress and Dominion should the Commission subsequently determine, through experience, that additional time is, in fact, needed to coordinate, hear and determine one or more of their annual fuel charge adjustment, REPS and DSM/EE cases. The Dominion schedule is particularly abbreviated and is the one most likely to require a future adjustment. Further, the Commission declines to revise the filing dates for interventions, intervenor testimony, and utility rebuttal testimony presently set forth in Rule R8-55(h), (i) and (j). There has been no compelling showing by the electric public utilities in support of their proposals to change these longstanding filing schedules. Likewise, the Commission finds good cause to deny Nucor's request that Rule R8-55(j) be revised to allow the Public Staff and other intervenors an opportunity to file surrebuttal testimony. The utilities have the burden of proof in fuel charge adjustment cases and, for that reason, have the right, as a general rule, to present the closing evidence in rebuttal. The Commission does, however, have the discretion, on a case-by-case basis, to allow surrebuttal testimony based upon a showing of good cause.

ISSUE 4. Updating experience modification factor (EMF) rider for over- or under-recoveries

Duke proposed that the methodology in Rule R8-55(d)(3) for establishing the EMF rider be changed to allow the incorporation of experienced over- or under-recoveries "up to thirty (30) days" rather than "through the date that is thirty (30) calendar days" prior to the hearing date to allow the use of a month-end amount consistent with Duke's fuel accounting practices.

In its reply comments, the Public Staff agreed with this change.

The Commission, therefore, concludes that Rule R8-55(d)(3) should be revised as proposed by Duke.

ISSUE 5. Information and data to be filed by Dominion

Dominion noted that G.S. 62-133.2(a3) requires it to exclude costs identified in Rule R8-55(a)(3) and (a)(5) as fuel costs. Dominion requested an affirmative statement in Rule R8-55 that these items need not be filed by the Company and proposed a change to the definition of "cost of fuel and fuel-related costs" in Rule R8-55(a).

In its reply comments, the Public Staff stated that it does not oppose an affirmative statement of this limitation, but recommended that it be included in the subsection (e) filing requirements rather than in the definitions. The Public Staff recommended a similar change to Rule R8-52(a).

The Commission concludes that Rules R8-52(a) and R8-55(e) should be revised, with slight modification, as proposed by the Public Staff in response to Dominion's request.

ISSUE 6. Non-uniform increments and decrements and peak demand information

Progress proposed to add the following sentence to Rule R8-55(d)(1): "The costs shall be allocated among customer classes in accordance with G.S. 62-133.2(a2)." Progress also proposed that the filing requirements in Rule R8-55(e)(1) include "peak demand by customer class." CIGFUR commented that this information should be part of the annual filing in a format deemed necessary by the Commission for the required allocations.

CIGFUR noted that Rule R8-55(d)(3) does not explicitly recognize that differing riders may be required for different classes of customers under G.S. 62-133.2(a2)(2) and (a3). CIGFUR suggested that subsection (d)(3), and perhaps subsection (e)(13), should be revised to provide for non-uniform riders.

In its reply comments, the Public Staff stated that it does not oppose the changes proposed by Progress or CIGFUR's suggestion with respect to Rule R8-55(d)(1), but recommended that the changes be made in a slightly different form.

The Commission finds good cause to adopt the rule revisions to R8-55(d) in the form proposed by the Public Staff. The Commission also finds good cause to adopt the "peak demand by customer class" language revision to Rule R8-55(e)(1) advocated by Progress and CIGFUR. The Commission finds no compelling reason to amend Rule R8-55(e)(13) as suggested by CIGFUR.

ISSUE 7. Interest on under-collections of fuel costs and fuel-related costs

Both Duke and Progress proposed changes to Rule R8-55(d) to require interest on under-collections of the reasonable and prudently incurred cost of fuel and fuel-related costs recovered through the EMF rider, arguing that a utility incurs a carrying cost on under-recoveries just as customers experience a lost opportunity cost on over-recoveries.

In its reply comments, the Public Staff noted that the Commission considered and rejected this proposal many years ago. In its Order Revising Rules and Procedures, issued August 14, 1986, in Docket No. E-100, Sub 47, the Commission noted that the time lag between the under-collection of reasonable and prudently incurred fuel costs and future revenue realization of that under-collection “should provide the utility with considerable incentive to minimize its fuel costs.” In its Order Adopting Amended Rule R8-55, issued April 27, 1988, in Docket No. E-100, Sub 55, the Commission stated:

> G.S. 62-130(e) requires that overcollections by a utility from its customers shall be refunded with interest and, accordingly, the Commission has amended its Rule R8-55 to provide for each utility to refund any overcollections of reasonable and prudently incurred fuel costs through the operation of the EMF rider with interest.

In a subsequent proceeding, the Commission addressed a proposal by Dominion to include in rate base as an element of working capital the average balance of unrecovered fuel expense (net of federal income tax) because the company was allowed no interest as part of the EMF. In its Order Approving Partial Rate Increase, issued February 14, 1991, in Docket No. E-22, Subs 314 and 319, the Commission rejected this proposal, saying, “Allowing a return on the underrecovery would negate this incentive.”

In his reply comments, the Attorney General took the position that neither the Public Utilities Act nor Senate Bill 3 authorizes the recovery of interest on fuel cost under-collections and that there is no statutory basis for the companies’ proposed amendment. The Attorney General noted that, in 1981, the General Assembly added subsection (e) to G.S. 62-130, which provides as follows:

> (e) In all cases where the Commission requires or orders a public utility to refund moneys to its customers which were advanced by or overcollected from its customers, the Commission shall require or order the utility to add to said refund an amount of interest at such rate as the Commission may determine to be just and reasonable; provided, however, that such rate of interest applicable to said refund shall not exceed ten percent (10%) per annum. (1981 N.C. Sess. Laws, c. 461, § 1)

According to the Attorney General, the Commission’s present Rule R8-55(c)(5), requiring interest on an over-collection of fuel costs, expressly cites the above subsection and tracks its language. The General Assembly enacted the fuel cost statute, G.S. 62-133.2, in 1982. It adopted extensive amendments to the statute as part of Senate Bill 3. See Senate Bill 3, Sec. 5. It is presumed that the General Assembly acted with full knowledge of prior and existing law. See State ex rel. Utils. Comm’n v. Thornburg, 84 N.C. App. 482, 353 S.E.2d 413, disc. rev. denied, 320 N.C. 517, 358

S.E.2d 533 (1987). If the General Assembly had intended to authorize the Commission to require customers to pay interest on a utility's fuel cost under-collection, then it easily could have done so in Senate Bill 3. In the absence of such authority, the Commission should not alter its present rule.

The Attorney General noted that the Commission has approved settlement agreements that included interest on an anticipated under-collection of fuel costs where the agreement is made to avoid customer rate shock. In those cases, the Commission found the interest charge to be justified because the utility was agreeing to delay the receipt of fuel revenues that it otherwise was entitled to collect. See Order Approving Fuel Charge Adjustment, Docket No. E-2, Sub 868, at 23 (Sept. 26, 2005). In contrast, there is no equitable basis for an absolute requirement that the utilities recover interest on every under-collection of fuel costs. The utilities have decades of experience in operating generating plants and purchasing fossil fuels. Further, in the annual fuel cost proceedings the Commission gives due deference to the utilities' projections of their fuel costs. Thus, the Attorney General took the position that it is fair that the utilities bear the carrying costs when their projections result in an under-collection.

CIGFUR took the position that interest on under-recoveries of fuel and fuel-related costs should not be allowed. Allowing utilities to pass this category of costs through to customers via a rider to rates with a true-up provision is a major exception to the statutory scheme of ratemaking utilized in North Carolina. Normally, a utility is not entitled to recover increases in costs without examination of increases in revenues and other factors relevant to determining a fair return. G.S. 62-133. Allowing interest on any underrecovery in addition to the true-up is not warranted and would inequitably place all the risk and burden on the ratepayers.

CUCA took the position that the Commission should reject the utilities' proposal for at least three reasons: (1) The Commission has had a long-standing practice of refusing to allow interest to be accrued on fuel expense under-collections. Senate Bill 3 did not modify the fuel expense collection provisions to allow for the accrual of interest on fuel expense under-collections, so the Commission should not now do so through a rulemaking process designed to implement Senate Bill 3. (2) Allowing interest to accrue on over-collections in order to protect ratepayers and preventing interest from accruing on under-collections forces the utilities to be as accurate as possible in their expense projections. If under-collections were allowed to accrue interest, the utilities could "game the system" by intentionally under-collecting when the rate of interest accrual exceeded the available market rate. (3) Annual rate adjustments for fuel and REPS costs are exceptions to standard ratemaking for the benefit of the utilities. They should not be allowed to further benefit from the accrual of interest on their under-collections. CUCA therefore asked the Commission to retain its policy of precluding the accrual of interest on utility expense under-collections.

The Commission finds good cause to deny the utilities' proposal to recover interest on under-collections of fuel costs and fuel-related costs for the reasons of law and policy previously set forth in Commission orders and for the reasons generally asserted by the Public Staff, the Attorney General, CIGFUR, and CUCA in their comments in this proceeding. If the General Assembly had intended to authorize the Commission to require customers to pay interest on a utility's under-collection of fuel costs, then it easily could have done so in Senate Bill 3. In the absence of any such legislative intent or authority, the Commission will not alter its present rule.

ISSUE 8. Recovery of costs incurred to comply with the Swine Farm Methane Capture Pilot Program

CUCA noted that the definition of "cost of fuel and fuel-related costs" in Rule R8-55(a) includes as a separate item (7): "All costs of compliance with the Swine Farm Methane Capture Pilot Program pursuant to North Carolina S.L. 2007-523 [(Senate Bill 1465)]." CUCA commented that electricity generated from swine farm methane recapture satisfies G.S. 62-133.7(e) and should be recovered under G.S. 62-133.2(a1)(6). Therefore, in CUCA's view, the costs should be treated as a subcategory of Rule R8-55(a)(6), not as a separate category. CUCA stated that this is important because costs recovered in subsection (a1)(6) are subject to the 2% cap under G.S. 62-133.2(a2). CUCA proposed that Rule R8-55(a)(7) be deleted, Rule R8-55(a)(8) be renumbered, and Rule R8-55(a)(6) be rewritten.

In its reply comments, the Public Staff disagreed with CUCA's proposal. According to the Public Staff, Section 4(d) of Senate Bill 1465 provides that each electric public utility that serves a swine farm selected for participation in the Swine Farm Methane Capture Program "is required to purchase all electricity generated by use of captured methane as a fuel by pilot program participants for seven years." Section 4(d) further provides, "All costs incurred by an electric public utility to comply with the provisions of this section may be recovered as costs of fuel pursuant to G.S. 62-133.2." Senate Bill 1465 contains no reference to G.S. 62-133.7 or to G.S. 62-133.2(a1)(6), which were enacted earlier. The Public Staff, therefore, asserted that the costs at issue are not subject to the 2% cap and are properly included in Rule R8-55 as a separate category. The Public Staff did, however, propose minor wording changes to Rule R8-55(a)(7) and (e)(9) consistent with its proposed revision to Rule R8-52(a)(1)(xii).

In its reply comments, CIGFUR supported CUCA's position on this issue. According to CIGFUR, swine waste resources are defined as renewable by Senate Bill 3. G.S. 62-133.7(a)(8). Consequently, the costs of purchases of power generated by swine waste resources are recoverable as purchases of power from renewable facilities pursuant to G.S. 62-133.2(a1)(6). Senate Bill 1465 requires only that all costs incurred by a utility to comply be recovered as costs of fuel pursuant to G.S. 62-133.2. There is no conflict between the provisions of G.S. 62-133.2 and Senate Bill 1465 and, therefore, no need or basis for a separate category of fuel costs other than those authorized by G.S. 62-133.2.

The Commission finds good cause to reject CUCA's proposal for the reasons set forth by the Public Staff. The Commission will also adopt the minor wording changes to Rule R8-55(a)(7) and (e)(9) proposed by the Public Staff. [limited in nature]

RULE R8-61

ISSUE 9. Permissible times for filing applications pursuant to G.S. 62-110.6 and G.S. 62-110.7

In its initial and reply comments, the Public Staff proposed to revise subsections (f) and (h) of Rule R8-61 to conform the rule to G.S. 62-110.6(b) and G.S. 62-110.7(b). The Public Staff noted that G.S. 62-110.6(b) provides that a public utility may file an application pursuant to G.S. 62-110.6 requesting the Commission to determine the need for an out-of-state electric generating facility that is intended to serve retail customers in North Carolina <u>at any time</u> after an application for a certificate of public convenience and necessity or license for construction of the generating facility has been filed in the state in which the facility will be sited. Similarly, the Public Staff noted that G.S. 62-110.7(b) provides that a public utility may request the Commission to review the public utility's decision to incur project development costs <u>at any time</u> prior to the filing of an application for a certificate to construct a potential nuclear generating facility to serve North Carolina retail customers.

In its initial comments, Duke noted that the proposed rules regarding a public utility's election to request ongoing review of construction of an in-state facility for which the Commission has granted a certificate of public convenience and necessity, Rule R8-61(e), or for an out-of-state facility for which the Commission has made a determination of need, Rule R8-61(g), would require that the utility file an application for an ongoing review <u>within 12 months</u> after issuance of the certificate by this Commission or by the state commission in the state in which the out-of-state facility is to be constructed. Duke asserted that neither the amendments to G.S. 62-110.1 nor the new G.S. 62-110.6 include such a time limitation on initiating an ongoing review. Notably, the proposed rules do not place the same time limitations on the Commission should it choose to initiate an ongoing review on its own motion. Duke asserted that the rules should provide utilities with the flexibility to request that the Commission initiate an ongoing review at any point during the construction phase.

Duke further noted that the new G.S. 62-110.7(b) clearly provides that a public utility may request that the Commission review the public utility's decision to incur project development costs for a potential nuclear electric generating facility "<u>[a]t any time</u> prior to the filing of an application" for a certificate for the facility. Yet, proposed Rule R8-61(h) would require that the utility file such an application before any project development costs are actually incurred. According to Duke, this time restriction is in clear contradiction with Senate Bill 3 and, therefore, must be changed to be consistent with G.S. 62-110.7(b).

In its initial comments, Progress proposed to amend subsections (f) and (h) of proposed Rule R8-61 to conform with the provisions of Senate Bill 3, which expressly state the time periods during which applications can be filed pursuant to G.S. 62-110.6 and G.S. 62-110.7.

In its initial comments, Dominion stated that the Commission's proposed Rule R8-61(f) restricts the time in which a utility may file an application for an out-of-state facility to "no later than 6 months after an application for a certificate of public convenience and necessity or license for the construction of the generating facility has been filed in the state in which the facility will be sited." G.S. 62-110.6(b) states that the public utility may file a petition "<u>any time</u> after the application for a certificate or license for the construction of the facility has been filed in the state in which the facility will be sited." (Emphasis added by Dominion). Objectively, there is no statutory basis for the Commission to limit the time in which the application can be filed.

According to Dominion, supporting the plain reading of the statute to allow filing "any time" is the General Assembly's statement that, in making its determination, "the Commission may consider whether the state in which the facility will be sited has issued a certificate or license for construction of the facility and approved a construction cost estimate and construction schedule for the facility." G.S. 62-110.6(c). The apparent policy reason for this provision is that the host state is likely to be the setting where all of the issues involving the authorization of the construction of the generation facility will be examined and the final construction schedule and costs will be determined. By waiting for the decision in the other jurisdiction, the Commission will have the benefit of all this information. The requirement that the Commission issue its order within 180 days of the filing of the petition also argues for allowing the utility to file after the host state's certificate is issued. In addition, the utility is not put in a position of filing with the Commission its estimated costs and construction schedule, receiving approval within 180 days, and then addressing revisions and cost changes required by the host state that cause the Commission's approval and the host state's approval to be out of sync. Presumably the Commission would allow the utility to file to amend the approval or capture such changes during the ongoing review process under R8-61(g), but this would be contrary to considerations of administrative and judicial efficiency and could delay construction of the facility.

Dominion also stated that there are immediate, practical implications for it if this rule is adopted with the six-month limitation. Dominion filed applications with the Virginia State Corporation Commission (Virginia SCC) relating to Ladysmith Units 3 and 4 on April 19, 2007, and received approval to construct the units on August 24, 2007. Dominion is concerned that the way the proposed rule is currently drafted, it will not be allowed to file an application with the Commission so as to obtain recovery for the facility in its next rate case pursuant to G.S. 62-110.6(d). Dominion also filed an application with the Virginia SCC on July 13, 2007, for a certificate for a clean-coal, carbon-capture compatible coal plant in Wise County, Virginia (Virginia City Hybrid Plant). If this proposed rule goes into effect, Dominion would be required to file its application with the Commission by January 12, 2008. Furthermore, it should also be noted that the Virginia SCC's hearing on the Virginia City Hybrid Plant will begin on January 8, 2008. If the plant is approved, the Virginia SCC could impose conditions on its approval that change certain aspects of the Company's original applications as filed with the Virginia SCC <u>and</u> the Commission. This would mean that the application filed with the Commission would not necessarily have any relation to the actual facility that would be built out-of-state.

Dominion further stated that, if a utility is required to file a petition with the Commission within the six-month time line, it is very possible that the petition will not reflect the actual costs or construction timeline of the facility. As a legal, practical and judicial efficiency matter, Dominion asserted that the utility constructing the out-of-state facility should be allowed to resolve issues in the host state before starting down a parallel, but potentially divergent, path before the Commission. This is not to say that the Commission cannot exercise its statutory authority to consider the need, costs and construction schedule of the facility.

Dominion stated that proposed Rule R8-61(h) is intended to implement new G.S. 62-110.7 regarding the approval and recovery of project development costs for in-state and out-of-state nuclear generation facilities. The last sentence of the proposed rule states: "Any such application shall be filed before any project development costs are actually incurred." According to Dominion, this restriction appears to go beyond the scope of G.S. 62-110.7. The statute states that a utility can file an application for project development costs "[a]t <u>any time</u> prior to the filing of an application for a certificate to construct a potential nuclear electric generating facility" in the host state. G.S. 62-110.7(b) (Emphasis added by Dominion). The Commission should not put greater constraints on the filing schedule than those imposed by the General Assembly. In application, the proposed rule's requirement is harmful to Dominion. Dominion stated that it is common knowledge that it plans to and is engaged in preliminary activities to expand its North Anna nuclear generating facility by constructing a new, third nuclear reactor for the generation of electricity at that site. Once completed, this project would benefit Dominion's customers by providing low cost and reliable electric power. Pursuant to G.S. 62-110.7, Dominion should be able recover its project development costs for this project in its rates. As drafted, the proposed rule would preclude Dominion from submitting these project development costs to the Commission for approval because they have already been incurred.

Duke, Progress and Dominion filed joint reply comments which stated that they are in agreement with the Public Staff in recommending that proposed Rule R8-61(f) be modified to allow applications to the Commission for demonstrating the need, estimated construction costs and construction schedule for an out-of-state facility to be filed at "any time" after an application has been filed in the host state. This interpretation is supported by G.S. 62-110.6(b). Duke, Progress and Dominion further stated that they are also in agreement with the Public Staff in recommending that the Commission modify proposed Rule R8-61(g) to allow applications to the Commission for review of decisions to incur project development costs for in-state and out-of-state nuclear facilities to be made at "any time" prior to filing an application for a certificate or license for the facility and that applications do not need to be filed before the project development costs are actually incurred. This interpretation is supported by G.S. 62-110.7(b).

In his reply comments, the Attorney General asserted that proposed Rule R8-61(f) should include a timeliness requirement for requesting a determination of need and an estimate of cost for an out-of-state generating facility. According to the Attorney General, Progress, Duke and Dominion commented that proposed

Rule R8-61(f) imposes an improper restriction by requiring an application for advance findings concerning a proposed out-of-state generating facility to be filed with the Commission “no later than 6 months after an application for a certificate of public convenience and necessity or license for construction of the generating facility has been filed in the state in which the facility will be sited.” In particular, Dominion offered several comments about the proposed rules’ potential effects on pending applications.

The Attorney General stated that G.S. 62-110.6 governs advance assurance of rate recovery from North Carolina customers for a generating plant to be built in another state. In essence, the statute authorizes a public utility to file a petition for approval of the need, estimated cost and projected construction schedule of an out-of-state plant that is intended to serve North Carolina residents. If the Commission grants approval and the other requirements of the statute are met, then the North Carolina portion of the reasonable and prudent costs of the plant will be recoverable in a general rate case. According to the Attorney General, the new statute has two main purposes. First, it provides a public utility with assurance, in advance of its next general rate case, that the utility will recover reasonable and prudent expenditures for a plant built outside of North Carolina. Second, it provides the Commission with advance oversight of the need, cost and construction schedule of an out-of-state plant for which the utility expects payment from North Carolina customers. However, neither of these purposes can be met unless the Commission is afforded a timely opportunity to review the proposed construction of the plant. Timely opportunity for review is the intent of the Commission’s proposed Rule R8-61(f).

According to the Attorney General, it is in the utilities’ best interests to provide the Commission with sufficient time to engage in an independent analysis of the proposed plant. For example, if a utility waits until the certificate is issued and construction begins, the Commission might conclude that its opportunity to make a meaningful determination of the need for the plant has been thwarted. The answer to the timeliness issue lies somewhere between the utilities’ position and the Commission’s proposed Rule R8-61(f). Rather than setting an absolute six-month deadline, the rule could state that a utility must file “a timely application that allows the Commission to conduct a meaningful review of the need, estimated cost and construction schedule.” That would address the Commission’s interest in having sufficient time to conduct an independent analysis of the facts, while also providing a utility some flexibility in the timing of its petition.

The Attorney General further stated that Dominion’s primary concern appears to be the effect that proposed Rule R8-61(f) may have on its ability to obtain Commission pre-approval of North Carolina cost recovery related to its pending certificate applications in Virginia. The General Assembly decided that G.S. 62-110.6 will not be effective until January 1, 2008. The Commission’s proposed rules cannot change the effective date or potential application, or lack of application, of the statute to a pending certificate petition in another state. However, to the extent that G.S. 62-110.6 is found to be applicable to such a petition, the Commission has the discretion to modify or waive procedural requirements contained in Commission rules in order to prevent an unjust result. See G.S. 62-80; Rule R1-30. In the alternative, to the extent that G.S. 62-110.6

does not apply to out-of-state certificate applications initiated prior to January 1, 2008, the only effect should be to eliminate the advance approval procedure. Thus, the utility would not be precluded from seeking rate recovery of the plant's costs in the traditional manner in a subsequent general rate case. The Attorney General also stated that Dominion made similar arguments regarding proposed Rule R8-61(h), which governs the procedure under new G.S. 62-110.7 for approval of a utility's decision to incur nuclear project development costs. The proposed rule would require that the application be filed "before any project development costs are actually incurred." For the reasons stated above, rather than setting an absolute bar, the rule could state that a utility must file "a timely application that allows the Commission to conduct a meaningful review of the utility's decision to incur project development costs." However, to the extent that the statute results in the Commission's refusal to approve a utility's decision to incur project development costs because costs were incurred prior to the statute's effective date, there was no bar against a utility filing for such assurance prior to the enactment of G.S. 62-110.7. See Order Issuing Declaratory Ruling, Docket No. E-7, Sub 819 (March 20, 2007) (granting general assurance to Duke for cost recovery of nuclear development costs).

In their reply comments, ED, SACE and SELC supported the Public Staff's proposal to amend Rule R8-61(f) to allow public utilities to apply for a determination of need to construct an out-of-state plant at any time after filing an application for a certificate in that state, rather than within 6 months as initially proposed by the Commission.

The Commission finds good cause to amend proposed Rule R8-61(f) and (h) as proposed by the Public Staff to conform with the language of G.S. 62-110.6(b) and G.S. 62-110.7(b). These changes were supported by Duke, Progress and Dominion as well. Nevertheless, in so ruling, the Commission agrees with the Attorney General that it is in the utilities' best interests to provide the Commission with sufficient time to engage in an independent analysis of generating units covered by G.S. 62-110.6 and G.S. 62-110.7. Timely opportunity for review was the intent of the Commission's proposed Rule R8-61(f) and (h). That being the case, despite its agreements with the Public Staff's proposed amendments, the Commission hereby encourages Duke, Progress and Dominion to make their filings under Rule R8-61 in as timely a manner as is reasonably possible so that the Commission will retain the maximum degree of flexibility in making the determinations required by the statutes in question. The Commission has a strong interest in having sufficient time to conduct an independent analysis of the facts, while also providing the utilities with some flexibility in the timing of their petitions. The Commission cannot fulfill its statutory obligation to review and decide these applications in a meaningful manner unless it is afforded an opportunity to hear and determine the relevant issues in a timely fashion. Because the electric utilities have the ability to time the filing of their cases, they are hereby requested to exercise that right in a fair manner with an eye toward ensuring a meaningful opportunity for review by the Commission and due process to all affected parties.

The Commission also finds good cause to amend proposed Rule R8-61(f) and (h) to require the electric utilities to prefile direct testimony with their applications under

G.S. 62-110.6 and G.S. 62-110.7. An application filed pursuant to either of these statutes must be decided by the Commission and an Order must be issued no later than 180 days after the date the petition is filed. For that reason, requiring the utility to prefile its direct testimony as part of its application will promote judicial efficiency and economy and ensure that the Commission and the parties to the case will have the maximum time allowed by law to litigate and decide the case.

ISSUE 10. Filing requirements contained in Rule R8-61(b)

In its initial comments, Duke stated that the proposed amendments to Rule R8-61(b) would add numerous additional filing requirements to an application for a certificate of public convenience and necessity for a generation facility, presumably to implement the new G.S. 62-110.1(f1), which provides assurances of cost recovery for generation facilities that have been subject to ongoing Commission review. According to Duke, G.S. 62-110.1(f1) makes clear that such recovery shall be through a general rate case. Proposed Rule R8-61(b)(7) would require the filing of the "projected effect of investment in the generating facility on the utility's overall revenue requirement for each year during the construction period." Such information is only relevant if the utility is recovering financing costs during construction through adjustments to rates that occur outside of a general rate case. Because Senate Bill 3 requires a utility to undergo a rate case to recover financing costs during construction (i.e., to include construction-work-in-progress in rate base), it does not appear that the proposed requirement in Rule R8-61(b)(7) would provide the Commission with relevant or meaningful information.

Duke further stated that proposed Rule R8-61(b)(1) similarly requires the filing of information regarding "reasonably anticipated future operating costs, including the anticipated in-service expenses associated with the generating facility for the 12-month period of time following commencement of commercial operation of the facility." This requirement would only make sense if the utility were permitted to automatically adjust rates when the generation facility comes online without the requirement of a general rate case. Again, because Senate Bill 3 requires a utility to undergo a rate case to recover anticipated in-service expenses for a generating facility, Duke asserted that the proposed requirement in R8-61(b)(11) would not provide the Commission with relevant or meaningful information.

Duke also asserted that proposed Rule R8-61(b)(5) and (8) add requirements to file an estimate of construction costs and the anticipated construction schedule. However, Rule R8-61(a)(9) and (10) already require the filing of this same information as a part of the 120-day advance filing requirement. Rule R8-61(b)(4) requires the filing of any updates to the Rule R8-61(a) information, so it appears that subdivisions (b)(5) and (8) of proposed Rule R8-61 are redundant.

Duke recommended that subdivisions R8-61(b)(5), (7), (8) and (11) be deleted.

In its initial comments, Piedmont proposed that, under Rule R8-61(b)(9), the firmness of upstream gas supplies should be taken into consideration when evaluating new electric generation certificate applications. For gas-fired facilities, the availability of upstream capacity to deliver gas to the new facility is a critical component of the ability of the new facility to operate as planned. Accordingly, it would appear reasonable to expect a showing that such capacity is available as part of the certificate process. Regarding Rule R8-61(b)(13), Piedmont suggested adding natural gas-fired generation to this provision on the basis that the benefits of displacing new electric load through energy efficiency (EE), demand-side management (DSM) and renewable energy resources are just as valid when applied to natural gas-fired electric generation as when they are applied to coal and nuclear generation facilities. This is particularly true, according to Piedmont, when the higher efficiency of using natural gas in direct space and water heating applications is considered and when taking into account the upward pressure that gas-fired electric generation places on wholesale natural gas prices.

In its reply comments, the Public Staff stated that it disagreed with Duke's suggested changes to the Rule R8-61(b) filing requirements. According to the Public Staff, the information required by subdivisions (7) and (11) of Rule R8-61(b) is relevant to whether the construction of the facility is justified by the public convenience and necessity, regardless of when the utility seeks to recover the cost through rates. As to Duke's assertions that the requirements of subdivisions (5) and (8) of Rule R8-61(b) are redundant because subdivisions (9) and (10) of Rule R8-61(a) already require the filing of the same information as part of the 120-day advance filing requirement and because Rule R8-61(b)(4) requires updates of Rule R8-61(a) information, the Public Staff noted that Rule R8-61(a) applies only to generating facilities with a capacity of 300 megawatts (MW) or more, while Rule R8-61(b) applies to all generating facilities for which a certificate is required. The Public Staff recommended that an applicant subject to the 120-day advance filing requirement in Rule R8-61(a) be allowed to request a waiver of any redundant filing requirement in Rule R8-61(b).

Regarding Piedmont's suggestions concerning Rule R8-61(b)(9), the Public Staff stated that it agreed in concept with Piedmont that the firmness of upstream gas supplies should be taken into consideration when evaluating new electric generation certificate applications, but noted that, in practice, upstream gas supplies are taken into consideration in certificate proceedings. Regarding Piedmont's suggestion to add natural gas-fired generation to Rule R8-61(b)(13), the Public Staff noted that the rule in question incorporates requirements of G.S. 62-110.1(e) that are applicable only to coal and nuclear facilities. Therefore, the Public Staff did not support or include Piedmont's proposed revisions to subdivisions (9) and (13) of Rule R8-61(b) in the proposed rules which were attached to the Public Staff's reply comments.

CHPA filed reply comments, but did not seek to intervene. CHPA stated that Rule R8-61(b)(13) requires a demonstration that EE measures, DSM, renewable energy resources, combined heat and power or any combination thereof, when compared to the proposed project, would not establish or maintain a more cost-effective and reliable generation system. Additional specificity should be added to this section to ensure that the demonstration is credible and comprehensive. According to CHPA, such provisions have proven problematic in other jurisdictions when they fail to differentiate between ratepayer and private sector capital. Clearly, the Commission plays a critical role in ensuring that ratepayer-backed capital serves the public convenience and necessity. However, privately-deployed, at-risk capital – which describes over 90% of CHPA installations – ought not be judged on these metrics since those investors (unlike investor-owned utilities) bear the full risk of loss if those projects are not competitive with alternative sources of power. CHPA recommended that the following requirements be included in Rule R8-61(b)(13): discussions of

- How the EE measures could defer or delay planned transmission and distribution facilities;
- How congestion on the transmission and distribution system is mitigated and the operational efficiency of the power grid is improved by EE measures, or any combination thereof;
- How the lead times of EE measures compare to the proposed coal or nuclear facility; and
- The impact on revenue requirements and rates when no ratepayer investment is required for EE measures.

With one exception, the Commission finds good cause to disallow the changes to Rule R8-61(b) proposed by Duke and Piedmont for the reasons generally expressed by the Public Staff. The one exception is that the Commission concludes that subdivision (9) to Rule R8-61(b) should be revised to incorporate a requirement that the public utility file information with a certificate application that addresses "adequacy of fuel supply" for the proposed generating unit. In response to Piedmont's subdivision (9) proposal, the Public Staff stated that upstream natural gas supplies are, in fact, taken into consideration in certificate proceedings. That being the case, the Commission finds benefit in codifying that practice as part of Rule R8-61(b). The Commission also agrees with the Public Staff that an applicant subject to the 120-day advance filing requirement set forth in Rule R8-61(a) can request a waiver from the Commission of any redundant filing requirement in Rule R8-61(b). Filing a waiver request is not a burdensome undertaking. Requests for waivers of truly redundant information will, of course, be granted. Parties to cases heard under Rule R8-61 can also present and elicit relevant evidence that may not be included or required to be filed as part of the utility's application.

In its reply comments, CHPA brought up a number of issues that it did not put forward in initial comments, including suggestions regarding amendments to Rule R8-61(b)(13). No other party had the opportunity to comment on these recommendations. Largely for that reason, the Commission hereby declines to adopt the amendments to Rule R8-61(b)(13) put forward by CHPA, but notes that the issues raised by CHPA appear to be relevant to certificate applications filed pursuant to G.S. 62-110.1; that such issues are arguably already covered by the proposed rule; and that such issues, if determined by the Commission to be relevant in a specific certification proceeding, may be raised by intervenors to the extent they are not directly addressed by the public utility in its application and testimony.

ISSUE 11. Time for filing an application for ongoing review of construction of a generating facility

In its initial comments, Duke stated that the proposed rules regarding the utility's election to request ongoing review of construction of an in-state facility for which the Commission has granted a certificate, Rule R8-61(e), or for an out-of-state facility for which the Commission has made a determination of need, Rule R8-61(g), would require that the utility file an application for an ongoing review within 12 months after issuance of the certificate of public convenience and necessity by this Commission or by the state commission in the state in which the out-of-state facility is to be constructed. However, neither the amendments to G.S. 62-110.1 nor new G.S. 62-110.6 include such a time limitation on initiating an ongoing review. Notably, the proposed rules do not place the same time limitations on the Commission should it choose to initiate an ongoing review on its own motion. Duke asserted that the rules should provide utilities with the flexibility to request that the Commission initiate an ongoing review at any point during the construction phase.

In its reply comments, the Public Staff stated that it supports proposed Rule R8-61(g) as written.[2] According to the Public Staff, the proposed rule is not contrary to the provisions of the statute and is within the Commission's general authority to prescribe rules for the orderly exercise of the right to ongoing review.

The Commission generally agrees with the reasoning of the Public Staff regarding this matter and hereby declines to adopt Duke's proposal. The Commission will retain the 12-month time limitations in Rule R8-61(e) and (g), but will further amend those subsections of the Rule to provide that the public utility may, prior to the conclusion of such 12-month period, petition the Commission for a reasonable extension of time to file an application based on a showing of good cause. Timely opportunity for review is the intent of subsections (e) and (g) of proposed Rule R8-61. The Commission cannot fulfill its statutory obligation to review and decide these applications in a meaningful manner unless it is afforded an opportunity to hear and determine the relevant issues in a timely fashion. The Commission has a strong interest in having sufficient time to conduct an independent analysis of the facts, while also providing the utilities with some flexibility in the timing of their petitions. The applicable 12-month filing requirement, including the opportunity to petition for an extension of time, are fair to the electric utilities in that they are allowed a reasonable degree of flexibility to determine the timing of their applications. The applicable 12-month filing requirements set forth in proposed Rule R8-61(e) and (g) will also ensure that the Commission and the parties to the cases will have an opportunity to consider the relevant issues on a timely and meaningful basis.

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[2] The Public Staff did not reference subsection (e) in its comments, but did not propose to change the 12-month filing date or limitation set forth in the Commission's proposed Rule R8-61(e). The rationale offered by the Public Staff in its comments regarding subsection (g) is also consistent with the 12-month filing date or limitation contained in subsection (e).

The Commission also finds good cause to amend proposed Rule R8-61(e) and (g) to require the electric utilities to prefile direct testimony with their applications under G.S. 62-110.1(f) and G.S. 62-110.6. Requiring the electric utility to prefile its direct testimony with its application will promote judicial efficiency and economy and provide an opportunity for a meaningful review of all relevant issues in the case on a reasonable time schedule.

ISSUE 12. Proposed Rule R8-61(i)

In their initial comments, ED, SACE and SELC stated that Senate Bill 3's provision for the possibility of utility recovery of the costs of construction work in progress (CWIP) represents a new public policy for the State. For this reason, ED, SACE and SELC asserted that additional protection for ratepayers is warranted. In particular, it is important that continued construction of a facility should depend on its remaining investment contributing to a least-cost mix of demand-side initiatives and generation resources. Specifically, ED, SACE and SELC suggested a new paragraph to read:

> (i) It shall be presumed that construction costs are not reasonable if a public utility continues to construct a facility after it has learned that it may establish a more cost-effective and reliable generation system with energy efficiency measures; demand-side management; renewable energy resource generation; combined heat and power generation; or any combination thereof. A public utility may reach this determination at any time, but must re-establish that the construction and operation of the facility remains in the public interest whenever it files information with the Commission that indicates a decrease in costs for reasonable alternatives to construction or when the costs of the facility have increased as demonstrated by a revised cost estimate as required by (e) or (f).

In their joint reply comments, Duke, Progress and Dominion stated that the new subsection (i) proposal made by ED, SACE and SELC is based upon the faulty supposition that inclusion of CWIP in rate base is a "new public policy for the State." On the contrary, the Commission permitted the inclusion of CWIP in rate base as far back as the 1960s (with an offsetting adjustment to remove from utility operating income for return Allowance for Funds Used During Construction capitalized on the CWIP). The General Assembly has acted on this issue on several occasions, amending G.S. 62-133(b)(1) in 1977 to require the inclusion in rate base of "reasonable and prudent expenditures for construction work in progress after the effective date of this subsection [July 1, 1979]," and amending it again in 1982 to provide that CWIP "may be included to the extent the Commission considers such inclusion to be in the public interest and necessary to the financial stability of the utility in question." Since the effective date of the 1982 amendment, the utilities pointed out that the Commission has been selective in allowing CWIP to be included in rate base. For example, in its November 11, 1982 Order in Duke Power Company's Docket No. E-7, Sub 338 the Commission allowed CWIP associated with the McGuire nuclear station to be included in rate base. Therefore, given that the premise of the proposal by ED, SACE and SELC is inaccurate, it should be rejected.

In its reply comments, the Public Staff took the position that proposed subsection (i) is inappropriate. The Public Staff stated that the cost-effectiveness of generating facilities compared to demand-side and other supply-side options will be addressed in the utilities' integrated resource plans (IRPs) pursuant to G.S. 62-(a)(3a), G.S. 62-110.1(c), G.S. 62-133.8(b) and Article 11 of the Commission's rules. G.S. 62-110.1(e) provides that the certificate for the construction of a coal or nuclear facility shall be granted only if the Commission makes certain findings with respect to cost-effectiveness. Once a certificate has been granted, construction may not be cancelled without approval from the Commission based on a finding that the construction is no longer in the public interest. The Commission has ample authority under G.S. 62-110.1(e1) and (f) to modify or revoke a certificate if it makes certain findings with respect to the need for the facility and the cost of construction. According to the Public Staff, the new subsection proposed by ED, SACE and SELC is not only unnecessary but also inconsistent with the statutory scheme.

The Commission agrees with the Public Staff and the utilities on this issue. Therefore, the Commission hereby declines to adopt the amendment to Rule R8-61 proposed by ED, SACE and SELC. The provisions of Senate Bill 3 and the rules to be adopted by the Commission to implement that legislation provide ample protections to ensure that the principles of cost-effectiveness and least cost planning will be observed in North Carolina. For that reason, proposed subsection (i) is inappropriate, unnecessary and inconsistent with the comprehensive statutory scheme reflected in Chapter 62 of the North Carolina General Statutes as amended by Senate Bill 3.

ISSUE 13. Amendment to Rule R8-61(f) filing requirements

In its initial comments, NC WARN stated that a major compromise reached in the legislative debate on Senate Bill 3 involved the assurance that utility companies would have to prove that renewable energy and energy efficiency measures "would not establish or maintain a more cost-effective and reliable generation system" before building new coal or nuclear construction. G.S. 62-110.1(e). However, the rules put forth by the Commission only require utility companies to satisfy this test for in-state facilities. NC WARN stated that the utilities do not have to meet this requirement for out-of-state facilities, even though the North Carolina customers would pay for the new power plants, and the plants would require the equivalent of the certificate of convenience and necessity, and the annual review. G.S. 62-110.6 and 110.7. As an example, Duke could build the proposed Lee nuclear plants in South Carolina without having to prove, and without having the Commission find, that the proposed facility is cheaper than renewable energy and efficiency.

In its initial comments, Duke recommended that Rule R8-61(f) be clarified to better align its provisions with the requirements of G.S. 62-110.6 as follows:

> The application shall include that information required by subsection (b) of this Rule to the extent that it is pertinent to the showing of need for the generating facility and the estimated construction costs and proposed construction schedule for the generating facility, supported by relevant testimony.

In their joint reply comments, Duke, Progress and Dominion stated that NC WARN's suggestion is not supported by Senate Bill 3 and is unnecessary. Senate Bill 3 is specific in only requiring the utility to demonstrate that cost-effective DSM/EE programs cannot meet the proposed resource need before being granted a certificate to build a new coal or nuclear generating facility if the new supply side resource is to be constructed in North Carolina. The General Assembly did not impose this obligation on generation resources to be built outside of North Carolina. This is not to say that the Commission does not have the authority to review a utility's decision to build an out-of-state facility if the utility attempts to recover a portion of the costs from North Carolina ratepayers. G.S. 62-110.6 grants the Commission the authority to determine the need for the facility, and a utility must also demonstrate that the selection of the resource in question was prudent and that the costs of the resource are just and reasonable. Thus, when a utility seeks to recover the North Carolina allocated portion of the costs of a new generation resource built in another state, the Commission will determine whether the selection and construction of the generation resource in question was prudent and disallow recovery of any costs associated with the resource that are found to be imprudent, unjust or unreasonable. The Commission should not, however, impose a burden by regulation that the General Assembly chose not to impose when it clearly could have done so explicitly, just as it did in the context of in-state facilities.

The Public Staff did not file comments on these issues, but did recommend in its markup of the proposed rules that the word "generally" be deleted from Rule R8-61(f). The Public Staff offered no rationale in support of this proposed change.

The utilities' position on this issue has merit. Therefore, the Commission finds good cause to amend Rule R8-61(f) consistent with Duke's initial comments, subject to minor wording changes. The sentence at issue will now read as follows:

> The application shall be supported by relevant testimony and shall include the information required by subsection (b) of this Rule to the extent such information is relevant to the showing of need for the generating facility and the estimated construction costs and proposed construction schedule for the generating facility.

The applicable provision of Rule R8-61(f), as set forth above, conforms more closely to the requirements of G.S. 62-110.6 than the Commission's original proposal. However, it does not impair the ability of the parties to a case to conduct discovery or elicit and present relevant evidence that may not be included or required to be filed as part of the utility's application. [possible info relevant at need and cost recovery]

ISSUE 14. Ratemaking adjustment for CWIP for canceled generating facility

In its initial comments, NC WARN stated that it was concerned that the proposed rules omit any reference to refunding CWIP to ratepayers for plants that are incomplete and abandoned. NC WARN noted that Senate Bill 3 mandated that "the Commission shall make any adjustment that may be required because costs of construction previously added to the utility's rate base pursuant to [CWIP] are removed from the rate base and recovered in accordance with this subsection." G.S. 62-110.1(f2) and (f3). NC WARN asserted that it is unclear if the Commission has simply decided to put off these rules until the future or has decided that rules in this area are not needed.

In their joint reply comments, Duke, Progress and Dominion stated that NC WARN appears to recommend that, in the event a generation facility is canceled, a utility should be required to refund certain costs recovered as a result of the inclusion of any CWIP in rate base. This is both violative of traditional ratemaking principles and inconsistent with G.S. 62-110.1(f2) as amended by Senate Bill 3. Subsection (f2) states that, in the event a plant is canceled and, prior to cancellation, the utility had been allowed to include CWIP associated with such plant in rate base, the "Commission shall make any adjustment that may be required because costs of construction previously added to the utility's rate base pursuant to subsection (f1) of this section are removed from the rate base and recovered in accordance with this subsection." As a result, in the event a plant is canceled under the circumstances contemplated by subsection (f2), the CWIP will simply be removed from the utility's rate base in its next general rate case and the cost of construction will be recovered as contemplated by this subsection.

The Commission concludes that it is not necessary to adopt rules to address the provisions of G.S. 62-110.1(f2) and (f3) in response to NC WARN's assertion that those provisions require "refunding construction work in progress (CWIP) to ratepayers for plants that are incomplete and abandoned." Subsections (f2) and (f3) of G.S. 62-110.1 specifically provide that this is an issue to be decided in a general rate case. General rate cases provide a forum for opposing parties to present evidence on contested ratemaking issues and file legal briefs in support of their positions. The issue raised by NC WARN is a ratemaking matter that is better addressed and decided in the context of an actual contested case, rather than in this rulemaking proceeding.

RULES R8-64, R8-65 & R8-66

ISSUE 15. Adoption of renewable energy certificate (REC) tracking system

G.S. 62-133.7(a)(6) defines a "renewable energy certificate" as:

> a tradable instrument that is equal to one megawatt-hour of electricity or equivalent energy supplied by a renewable energy facility, new renewable energy facility, or reduced by implementation of an energy efficiency measure that is used to track and verify compliance with the requirements of this section as determined by the Commission. A 'renewable energy certificate' does not include the related emission reductions, including but

> not limited to, reductions of sulfur dioxide, oxides of nitrogen, mercury, or carbon dioxide.

> G.S. 62-133.7(i)(7) requires the Commission to:

> Develop procedures to track and account for renewable energy certificates, including ownership of renewable energy certificates that are derived from a customer owned renewable energy facility as a result of any action by a customer of an electric power supplier that is independent of a program sponsored by the electric power supplier.

As proposed, the rules do not require or rely on either a third-party tracking system or an in-house tracking system, but address the issues of REC tracking and potential double-counting in several ways:

- Proposed Rule R8-66 would require the owner of each renewable energy facility that intends to sell electric power or RECs to an electric power supplier for REPS compliance to first register with the Commission. This would apply to all non-utility generators, whether in-state or out-of-state, certificated or exempt from certification, metered or non-metered. As part of this registration, each generator would be required to annually file with the Commission the generation data that they annually file with the Energy Information Administration (EIA), United States Department of Energy.
- Proposed Rule R8-67(b)(2) requires each electric power supplier to provide sufficient information, including supporting documentation, relating to the purchase of renewable energy or RECs to annually demonstrate REPS compliance.
- Proposed Rule R8-67(d)(2) requires each electric power supplier to include appropriate language in all agreements for the purchase of RECs (whether or not bundled with the purchase of electric power) prohibiting the seller from remarketing the RECs being purchased by the electric power supplier.

The Attorney General took the position that proposals for development of an electronic tracking system with a third party administrator merit further study, stating that comments by other parties "make a strong case for further study of tracking options to determine the relative costs and benefits of adopting a centralized tracking system with an independent administrator either by participation in a regional platform or by adoption of a mechanism that has been successful elsewhere."

CHPA agreed that establishing an electronic REC tracking system that is administered by a third party and is transparent and accessible to stakeholders should not be foreclosed.

CPV expressed concern that the proposed rules do not provide for REC trading. "It is not unreasonable to expect that unbundled trading of RECs and energy will likely occur in the future." CPV stated that as markets become more sophisticated, it is very possible that others will sell unbundled RECs and energy. It appears likely that some form of tracking system will be necessary to manage the market from the beginning, and certainly as it evolves.

ED, SACE and SELC took the position that the Commission should reconsider its preliminary conclusion that an electronic tracking system for RECs and renewable energy generation is not required. They stated that the costs of such a system would be very small in comparison to the total cost of renewable generation. It would be burdensome to have to obtain through discovery information to validate the fairness of the incremental costs claimed by each utility. North Carolina has the opportunity to integrate its tracking system with that of other states from the beginning.

ElectriCities and NCEMC supported the Commission's initial conclusion that it has the ability to obtain the data necessary to ensure compliance without the necessity for an electronic tracking system.

NCSEA proposed that an automated REC tracking system be adopted to increase transparency, minimize workload needed to assure compliance, streamline cost-recovery processes and promote a more certain environment for renewable energy generation development. A REC tracking system would make the transfer of unbundled RECs more transparent and make it apparent whether an electric power supplier had made a "reasonable effort" to comply with REPS. NCSEA stated that implementing a REC tracking system would eliminate the need for a true-up for cost recovery of renewable energy, and proposed that the first quarter of 2008 be used to contract, design and test an automated REC tracking system, with implementation to occur on January 1, 2009. During 2008, NCSEA recommended that the Commission operate an in-house tracking system based on data from quarterly reports of meter data filed by registered renewable energy generators (generators below 1 MW would file annually, potentially via an aggregator).

NC WARN stated that the initial version of the rules is deficient in that it does not track renewable energy "credits."

Progress, Duke and Dominion initially opposed a third-party tracking system, but agreed in their reply comments that development of an electronic tracking system may make sense. It would provide regulators, utilities and developers an accounting system that is transparent and trusted. They urged that it be cost-effective and not administratively burdensome. Dominion requested that the system be compatible with the GATS (Generation Attribute Tracking System) renewable energy tracking system employed by PJM because its generators already participate in that system. A third party should provide the REC tracking system that serves as the place where parties obtain generation numbers on exactly how much renewable energy/RECs have been generated by a facility (that has been approved by the Commission) over time. The REC tracking system serves as the bookkeeper. The utilities recommended that the Commission approve the proposed rules as soon as practical and establish a process to further investigate and receive proposals for implementation of a REC issuance and tracking system.

Small Hydro stated that it is important that RECs, which are defined as tradable instruments, be accurately identified, tracked and retired in a way which meets the purposes of the North Carolina REPS.

SunEdison and Solar Alliance endorsed an electronic tracking system as a critical enabling platform for ensuring REPS compliance, and proposed that, within 60 days after the rules are adopted, the Commission should open an investigation into the costs, benefits, feasibility and implementation options related to establishing a centralized, statewide electronic REC tracking system for compliance year 2009 and thereafter. This system would include: registering and de-registering renewable energy facilities; maintaining verified output data for each facility and assigning RECs to the output; a platform for transferring RECs among generators, brokers/aggregators and electric power suppliers; retirement of RECs used for compliance; and the generation of reports for the Commission. SunEdison and Solar Alliance proposed proportional user fees levied on eligible generators and regulated suppliers.

Wal-Mart recommended, after reviewing other parties' comments, that the Commission not rush into the immediate implementation of a trading platform. Wal-Mart suggested that the Commission wait until a later date to implement such a platform in order to gather all of the appropriate facts.

The Public Staff took the position that the best procedure for issuing and tracking RECs would be a single, centralized, computerized tracking system operated by a third-party administrator. For now, the Commission should require certain documentation to validate REPS credits, as listed in the Public Staff's proposed R8-67(b)(2) compliance report requirements: (viii) a list of each renewable energy facility or energy efficiency supplier for which REPS credits are claimed; (ix) the amount of renewable generation or EE provided by each facility or supplier for which REPS credits are claimed and the amount paid for them; and (x) an affidavit from each renewable energy supplier that provided renewable energy for which REPS credits are claimed certifying the renwable character of the energy delivered to the purchaser and listing the dates and amounts of payments received and all meter readings.

The Public Staff stated that it had discussed the need for an electronic REC tracking system with numerous parties. As a result of those discussions, the Public Staff took the position that such a system deserves serious consideration. The Commission's duty to track and verify RECs and REPS compliance through these proposed rules could become quite complex and burdensome. An electronic REC tracking system with an administrator that acts as the agent for the Commission, relying upon North Carolina rules and standards, could simplify the tracking, verification and enforcement of compliance. Many parties have credibly informed the Public Staff that a simple and transparent electronic REC tracking system will result in a more robust REPS. The Public Staff, therefore, requested that the Commission remain receptive to the consideration of an electronic REC tracking system in the near future.

The Commission notes that the potential benefits of a REC tracking system, depending on how it is designed, would be its ability to:

- “Account for” RECs (their creation, use for compliance and retirement) in a consistent manner for all renewable energy facilities whose output is used for REPS compliance and electric power suppliers that must comply with REPS;
- Generate reports that would assist the Commission and all stakeholders to monitor REPS compliance; and
- Create a market for RECs that meet the definitions in Senate Bill 3 by easing the ability to purchase and sell RECs and providing price transparency that might encourage market development.

Some parties asserted that a tracking system can ensure against double-counting of RECs. While it is true that a given REC can only have one “existence” within a given tracking system, there does not appear to be any mechanism, other than certified attestations, to prevent a generator from participating simultaneously in several REC tracking systems and creating multiple RECs for the same megawatt-hour of energy production. Another argument for a REC tracking system is that it is needed to assure data accuracy. The only way a tracking system can certify/verify the creation of a REC, however, is via metered generation data transmitted directly to the tracking system. A number of states are considering whether to implement wireless smart meter technology that would upload meter data monthly for all generators, but the cost of metering a very small generator could outweigh the value of the RECs it generates. With regard to creating a REC trading market, REC price transparency is not inherently necessary for REPS success in North Carolina. First, the population of suppliers that need North Carolina RECs for REPS compliance is small. Those entities with RECs to sell should have no problem “finding” the buyers and offering their RECs for purchase. Secondly, an organized market might actually cause the price of RECs in North Carolina to go up. Theoretically, the combination of cost caps and REPS requirement will create an “economic band” of renewable energy facilities that will be developed in North Carolina.

On balance, the Commission is persuaded that a third-party REC tracking system would be beneficial in assisting the Commission and stakeholders in tracking the creation, retirement and ownership of RECs for compliance with Senate Bill 3. The Commission is not persuaded at this time, however, that it should develop or require participation in a REC trading platform. As stated above, a REC trading platform is unnecessary for REPS compliance or for the development of renewable energy in North Carolina. Nothing in the Commission’s rules, however, would prevent the formation of and participation in a voluntary REC trading market in the event that such an institution would facilitate cost-effective compliance with the requirements of Senate Bill 3. The Commission will begin immediately to identify an appropriate REC tracking system for North Carolina. Until arrangements are completed for the use of a REC tracking system in North Carolina, the Commission will rely on registrations, certified attestations, contract terms and compliance reports by utilities and generators to track RECs and REPS compliance.

ISSUE 16. Registration requirements for renewable energy facilities

Proposed R8-66(b) would require the owner of each renewable energy facility that intends to sell electric power or RECs to an electric power supplier for REPS compliance to first register with the Commission. This would apply to all non-utility generators, whether in-state or out-of-state, certificated or exempt from certification, metered or non-metered. As proposed, Rule R8-66(b) would require renewable energy facilities to submit some of the same data that is currently required of qualifying facilities (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA) and small power producers when requesting a certificate of public convenience and necessity, namely:

(i) Name and contact information of the applicant.
(ii) Business structure information.
(iii) Description of generator.
(iv) Location of generator, including maps.
(v) Site ownership information.
(vi) Description of buildings, structures and operations.
(vii) Facility costs.
(viii) In-service date.
(ix) Applicant's plans for selling the electric output, wheeling, emergency generation, service life of the project and annual kWh sales.
(x) List of federal and state licenses obtained or applied for.

As proposed, Rule R8-66(b) would also require renewable energy facility owners to:

(xi) Annually file their Form EIA-860 with the Commission each time it is filed with the Energy Information Administration.
(xii) Certify that it is in substantial compliance with environmental laws and regulations.
(xiii) Certify that RECs sold to an electric power supplier for REPS compliance have not and will not be remarketed.
(xiv) Sign and verify the registration, which would be processed by the Chief Clerk.

As proposed, Rule R8-66(b) states that the following actions could make a facility ineligible for certification:

(xv) Falsification or failure to disclose required information.
(xvi) Failure to comply with environmental laws.
(xvii) Remarketing RECs.

Progress, Duke and Dominion stated that an essential part of the administration of a renewable portfolio system is a registration system for facilities that wish to provide renewable energy and/or RECs. The utilities supported a registration system as described in proposed Rule R8-66(b), provided that the costs of such a system are considered a cost of compliance and included in the cost caps.

CIGFUR took the position that the filing requirements should be amended to eliminate the requirement to file proprietary information that is not needed. If the information is needed, provision should be made for confidential treatment. Similarly, NCSEA stated that cost information as well as the identities of energy purchasers from a renewable energy facility are market sensitive information that should not be required to be filed or should be held confidential.

NC WARN expressed concern that the original rules do not "set forth a procedure for certifying or decertifying facilities as eligible renewable energy generators." It suggested this be accomplished by an application process and review by the Commission.

The Public Staff stated that it had reviewed comments that requested a reduction in the filing requirements and agreed that the project cost information is not necessary. The Public Staff recommended that the rule require that each registrant that is a "new" renewable energy facility provide documentation indicating that it meets the statutory definition. The Public Staff's proposed registration process would require the Chief Clerk of the Commission to adopt a numbering system that distinguishes between new renewable energy facilities and renewable energy facilities that are not new. For each registration, the Chief Clerk would determine whether the registration statement is complete, assign it a number, post it on the Commission's web site and notify the owner that the registration is complete. The Public Staff proposed that the rule direct the Chief Clerk to determine during the registration process whether the renewable energy facility is a "new" renewable energy facility and to assign it a corresponding registration number. Interested parties could challenge whether the facility is "new" or not. The Public Staff also stated that it is a common practice for the Commission to receive proprietary information on a confidential basis. The Commission should address requests for confidentiality on a case-by-case basis as it normally does.

The Public Staff proposed to add a requirement that the owner of the facility consent to the auditing of its books by the Public Staff insofar as they relate to transactions with North Carolina electric power suppliers. In reply comments, the Attorney General and CIGFUR stated that such a requirement might be unnecessarily burdensome and should be carefully considered.

SunEdison and Solar Alliance agreed with the Public Staff's proposal regarding auditing. SunEdison and Solar Alliance further argued that tracking systems only monitor compliance. These systems cannot be delegated the authority to certify whether an individual resource is eligible under a certain state's rules.

The Commission agrees with the Public Staff and concludes that it is not necessary for renewable energy facilities to file their cost information as part of the registration process. The Commission further concludes that it is also not necessary for renewable energy facilities to file information describing the facility's "buildings, structures and operations" as long as the information provided in the registration statement clearly explains the technology used by the facility to produce electricity.

The Commission concludes that all registered renewable energy facilities should annually report to the Commission whether they sold any RECs during the previous year and to whom. Rule R8-66 should require generators to make a contemporaneous filing with the Commission of the following portions of Form EIA-923[3]:

- Schedule 1 (identifying information);
- Schedule 5 (generator type, gross generation in MWh, net generation in MWh);
- Schedule 6 (for non-utility generators only, how much of their energy was sold to third parties); and
- Schedule 9 (changes in ownership).

Renewable energy facilities that are not required to file Form EIA-923 with the EIA should nonetheless file the same information with the Commission annually. Because most generators are already required to file this information with the EIA, the Commission concludes that this requirement will not add appreciably to a generator's costs.

The Commission agrees that the Public Staff will need the ability to audit meter data from renewable energy facilities and, therefore, finds good cause to include the Public Staff's proposed amendments to Rule R8-66 requiring renewable energy facilities to submit to auditing of their records relative to generator metering data as it relates to transactions with North Carolina electric power suppliers.

Lastly, the Commission does not believe that the Chief Clerk should be required to assess whether a registration statement is complete or to adopt a numbering system to differentiate which renewable energy facilities are "new." Instead, the Commission requests the Public Staff's assistance in reviewing each registration request and bringing to the Commission's attention issues of concern before the Commission approves the registration. The Commission, therefore, finds good cause to modify Rule R8-66 to include a procedure for processing registration filings.

ISSUE 17. Registration by electric power suppliers

As proposed, Rule R8-66 does not require electric power suppliers to register their renewable energy facilities.

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[3] The Commission has learned that the EIA is phasing out some of its required annual form filings and collapsing several into one new form, Form EIA-923. This form must be filed with the EIA annually starting March 30, 2009, by all generators larger than one megawatt that are connected to the electric grid, beginning with 2008 data.

The Public Staff proposed that renewable energy facilities should either be owned directly by an electric public utility <u>or</u> registered under Rule R8-66.

SunEdison and Solar Alliance disagreed with the Public Staff's position that there may be no reason to require utility-owned facilities to register for purposes of producing RECs. "Creating special sub-classes of generators whose fixed generator characteristics are not certified through the same process as others creates an illusory administrative efficiency which in fact significantly complicates the process."

The Commission concludes that renewable energy facilities owned by an electric power supplier, just like all other renewable energy facilities for which RECs are used for REPS compliance, should be registered and that this should be done as part of the electric power supplier's compliance plan. Resources that are part of the electric power supplier's integrated system should be treated in the same manner, whether they are located in North Carolina or in other states. Electric power suppliers that already have entered into contracts for renewable energy from out-of-state generating resources may register the seller's facility with the Commission so that the burden does not fall on the seller. In new contracts or contract extensions, the electric power supplier should require all sellers to register with the Commission. However, purchases, such as hydro allocations, from agencies of the federal government are exempted from this registration requirement.

ISSUE 18. Registration by entities not selling RECs for REPS compliance

G.S. 62-133.7(i)(7) requires the Commission to:

> Develop procedures to track and account for renewable energy certificates, including ownership of renewable energy certificates that are derived from a customer owned renewable energy facility as a result of any action by a customer of an electric power supplier that is independent of a program sponsored by the electric power supplier.

Proposed Rule R8-66 would require the owner of each renewable energy facility that intends to sell electric power or RECs to an electric power supplier for REPS compliance to first register with the Commission. As part of this registration, each generator would be required to file generation data and certify that it has not, and will not, remarket or otherwise resell any RECs.

Wal-Mart asserted that the proposed language of Rule R8-66(b) requires registration of renewable energy facilities that intend to sell power or RECs to an electric power supplier. Wal-Mart took the position that this type of registration would discourage customers from implementing energy generation facilities or EE measures. It raises a question concerning the Commission's jurisdiction to impose regulatory requirements on customer actions that are purely self-directed. Some facilities will sell their RECs to parties other than electric power suppliers and should not have to register with the Commission. Wal-Mart proposed rule modifications:

> Prior to selling electric power or renewable energy certificates to an electric power supplier pursuant to G.S. 62-133.7(b)(2) or (c)(2), the owner of a renewable energy facility or the owner of a renewable energy certificate shall first register with the Commission …. (2) Provided, however, that nothing in this rule shall be construed to require the owner of a renewable energy facility or a renewable energy certificate to sell electric power or the renewable energy certificate to an electric power supplier. Provided further, nothing in this rule shall be construed to require registration by the owner of a renewable energy facility or the owner of a renewable energy certificate absent a sale of electric power or a renewable energy certificate to an electric power supplier.

NCSEA agreed with Wal-Mart that only owners of renewable energy facilities or RECs who desire to sell the RECs or the energy should register with the Commission. Also, those generators who register should not be required to sell their output and/or RECs to electric power suppliers.

The Public Staff disagreed with Wal-Mart. The Commission needs the registration information regardless of whether an electric power supplier acquires a renewable energy facility's power directly from the facility or whether it instead obtains the power indirectly through a broker, an aggregator or some other intermediary. Registration does not interfere with a facility's freedom to choose how it will dispose of its electrical output, as Wal-Mart appears to believe. Once a facility has registered, it is entirely free to decide whether to sell its energy and its RECs separately or in bundled form, whether to sell them in North Carolina or elsewhere, and whether to sell them to an electric power supplier or some other party.

The Commission concludes that a renewable energy facility is not required to be registered unless and until its RECs are to be used by an electric power supplier for REPS compliance. Therefore, a renewable energy facility may sell its RECs to an entity other than an electric power supplier without registering. However, if the purchasing entity subsequently sells the RECs to an electric power supplier for REPS compliance, the third party must ensure that the renewable energy facility is registered with the Commission. Ultimately, it is the electric power supplier's responsibility to make sure that all of the renewable energy facilities upon which it relies for REPS compliance have registered with the Commission prior to filing its REPS compliance report.

ISSUE 19. Registration of out-of-state generators

Proposed Rule R8-66 would require the owner of each renewable energy facility that intends to sell electric power or RECs to an electric power supplier for REPS compliance to first register with the Commission. As proposed, this would apply to all non-utility generators, whether in-state or out-of-state, certificated or exempt from certification, metered or non-metered.

Progress, Duke and Dominion asserted that certain requirements of R8-64(b)(1) – (ii) description of applicant; (iv) location relative to highways, streets, etc.; (v) site ownership; (viii) facility cost; (x) applicant's plan for selling output; and (xi) status of federal and state permits for construction and operation – should not be required for the registration of out-of-state renewable energy facilities.

The Commission concludes that it is not necessary for out-of-state renewable energy facilities whose energy or RECs will be used for REPS compliance to provide registration information relative to (viii) the cost of the facility and (x) the applicant's plans for selling the output. The Commission does need to know the identity of the seller, the type of generator and fuel used, the facility's location and the facility's environmental compliance status, which are met via requirements (i), (ii), (iii), (iv), (v) and (xi), so those requirements should be retained.

ISSUE 20. Registration for facilities tracked by PJM's GATS

The proposed rule does not recognize that some renewable energy facilities and RECs that could be used for REPS compliance participate in PJM's GATS.

Dominion expressed concern about the requirement that all generators wishing to provide energy or RECs for REPS compliance must register with the Commission. Dominion stated that this requirement would create a barrier to its meeting the REPS in North Carolina and ultimately increase costs to North Carolina customers. Although Dominion recommended against setting up a system like GATS in North Carolina, it suggested that Rule R8-66 be amended to allow for the reporting of the purchase of RECs through an established tracking system such as GATS.

The Attorney General agreed with Dominion that registration with the Commission should not be necessary if the RECs proposed to be sold are validated by a regional transmission organization (RTO). Similarly, CIGFUR asserted that this proposal appears to be reasonable and efficient.

The Public Staff disagreed with Dominion. Although PJM's GATS does issue and track RECs, it does not register or certify renewable energy facilities; that function is performed by the state regulatory commissions in the PJM region. Each state has its own REPS statute and its own eligibility standards. The Public Staff recommended that the Commission refuse to grant a blanket exemption from registration for all facilities whose RECs are issued by PJM's GATS or a similar organization.

SunEdison and Solar Alliance asserted that tracking systems only monitor compliance. These systems cannot be delegated the authority to certify whether an individual resource is eligible under a particular state's rules. Certification cannot be legally sidestepped as Dominion proposes.

The Commission concludes that all renewable energy facilities that want their RECs to count toward REPS compliance need to register with the Commission. The Commission anticipates selecting a third-party to track RECs, but, even so, each facility will need to register with the Commission in order to ensure that it meets the unique requirements of Senate Bill 3.

ISSUE 21. Entities allowed to issue RECs

Neither Senate Bill 3 nor the proposed rules speak to the issue of who can issue RECs. Rule R8-67(b)(2) requires each electric power supplier to annually document its REPS compliance, including "the sources, amounts, and costs of REPS Credits claimed, by type: e.g., self-generation, co-firing, purchased electric power, in-state and out-of-state renewable energy certificates, energy efficiency." Subsection (b)(5) of the rule also requires that "[r]enewable energy certificates (whether or not bundled with the purchase of electric power) claimed by an electric power supplier for compliance … shall be retired and not used for any other purpose."

The Public Staff initially proposed a new rule, Rule R8-66(d), that would have provided for the registration of REC issuers. The Public Staff recognized that the Commission was not likely to establish a tracking system immediately and, therefore, proposed a system of registering all REC issuers. In its reply comments, the Public Staff withdrew that proposal, being persuaded by SunEdision and Solar Alliance that it would be counterproductive to have multiple REC issuers who might develop conflicting requirements and use inconsistent tracking procedures. In addition, the Public Staff expressed concern that if multiple REC issuers are given legal recognition by the Commission through a registration process, and subsequently the Commission adopts a centralized tracking system, the previously registered REC issuers may ask to be "grandfathered in" and allowed to operate alongside the centralized tracking system, thus negating the advantages of such a system. Instead of regulating REC issuers, the Public Staff proposed that, for now, the Commission require documentation by utilities in their annual compliance reports to validate RECs.

ED, SACE and SELC agreed with the Public Staff's initial proposal for registering REC issuers.

ElectriCities and NCEMC opposed the Public Staff's initial proposal to certify REC issuers, calling it unduly detailed and potentially burdensome.

NCSEA stated that allowing multiple third-party REC issuers would add an unnecessary level of cost and administration in the implementation of the REPS mandate. Similarly, SunEdison and Solar Alliance strongly recommended against approval of multiple REC issuing platforms. There is no precedent for such a system and it is likely to exponentially increase the complexity of REPS implementation and administration. Renewable generators should not be in the business of issuing or tracking RECs, nor should REC issuers be in the renewable generation business.

Small Hydro supported a system where RECs are issued by a registered third party to reduce the burden on small renewable generators who need to market their RECs to suppliers. This will make the market for RECs more open to smaller suppliers who need to acquire RECs to meet their REPS requirement. Because Senate Bill 3 uniquely includes some legacy generation and EE, the issuer must be registered with the Commission and demonstrate that it understands North Carolina's unique requirements.

The Commission concludes that there is no need to change the rule as originally proposed. The Commission plans to pursue a REC tracking system administered by a third party. That system will be authorized to track RECs that meet North Carolina's REPS criteria, including those produced by renewable energy facilities that register with the Commission.

ISSUE 22. Ensuring environmental compliance

G.S. 62-133.7(i)(5) requires the Commission to adopt rules to:

> Ensure that the owner and operator of each renewable energy facility that delivers electric power to an electric power supplier is in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources.

As proposed, R8-66(b)(3) requires the owner of a facility to certify that it complies with all environmental and conservation laws and regulations at the time it applies to the Commission for registration.

CIGFUR argued that the Commission is not the agency charged with enforcement of environmental laws. The proposed rules meet the intent of Senate Bill 3 via certification and provision of documents.

Wildlife expressed concern that the proposed rule is insufficient to implement the intent of the relevant statutory language. It stated that compliance should be assessed throughout the life of the project, not just once during the initial registration phase. It stated that compliance certification requires site visits and review by an entity other than the owner. Wildlife proposed that periodic review of facility operations be conducted by the Commission along with appropriate state and federal agencies. Such a review would be patterned after those conducted by the FERC for hydropower projects and would include a review of records and data maintained by the operators. If such a review process is not approved by the Commission, Wildlife requested that Rule R8-66(b)(3) include more stringent requirements for the annual compliance plan filed by electric public utilities, although it did not specify those requirements. In addition, Wildlife stated that the information as required at the time of registration, R8-64(b)(1), is not adequate to assess whether a proposed facility will have environmental impacts, as some proposed power production facilities may not require any licenses, permits and exemptions, but may still result in moderate to considerable impacts. Stating that site-specific and project-specific information is necessary for a proper environmental review, Wildlife proposed that Rule R8-64(b)(1) be revised by adding: "The application shall be accompanied by maps, plans and specifications setting forth such details and dimensions as the Commission requires." The Public Staff did not oppose this proposed revision.

The Commission finds good cause to adopt Wildlife's proposed amendment. Wildlife did not suggest any specific additions to the annual compliance plan filing to assist the Commission with monitoring environmental compliance. The Commission does not have the staff, the expertise or the statutory mandate to conduct periodic site reviews to ensure that all renewable energy facilities comply with all environmental requirements imposed by all units of government, especially those located in other states. The Commission, therefore, concludes that it will have to rely on assistance from third parties to meet this requirement. The proposed rules already require renewable energy facilities to assert compliance, both as part of the registration process and annually. Given the statutory requirement that the Commission assure that renewable energy facilities are in “substantial compliance” with environmental laws, the Commission finds good cause to add a provision to the rules that will allow third parties to challenge a registration on the grounds of noncompliance with environmental requirements. The Commission will then refer the matter to the appropriate environmental agency for review and await its recommendation prior to potentially suspending the facility’s registration.

ISSUE 23. Penalty for misconduct on the part of a registered renewable energy facility

Proposed Rule R8-66(b)(11) states that falsification or failure to disclose information in the registration statement, failure to comply with environmental laws, or remarketing of RECs “may result in the ineligibility of RECs sold to electric power suppliers in North Carolina, forfeiture of payments, fines, or other penalties.”

The Public Staff proposed that the sanction for misconduct on the part of a registered renewable energy facility should be revocation of registration, rather than invalidation of the RECs that the registrant has sold. Revocation of registration is a more effective sanction, because some renewable energy facilities are likely to sell their power directly to a utility, without any RECs being sold or issued. Under its proposed language, a renewable energy facility will have every incentive to avoid revocation of its registration, because after revocation its power cannot be used to meet the REPS requirement.

SunEdison agreed with the Public Staff that the penalty for misconduct by a generator should be revocation of its certification going forward, rather than invalidation of RECs already sold. A utility having purchased RECs from a generator later decertified would thus be held harmless.

The Commission finds good cause to adopt the Public Staff’s proposed language for R8-66(c)(7) from its reply comments, which would make “revocation of registration by the Commission” the sanction for falsification or failure to disclose information in the registration statement, failure to comply with environmental laws, or remarketing of RECs after they have been sold to one party. The Commission concludes that the rules should clarify that RECs emanating from energy produced prior to the revocation are valid for purposes of REPS compliance. The Commission also concludes that the rules should specify that revocation of registration is the sanction for failing to allow the Commission or the Public Staff to have access to books and records as necessary to audit REPS compliance.

RULE R8-67

ISSUE 24. Definition of "avoided cost rates"

The definition of "avoided cost rates" is set forth in proposed Rule R8-67(a)(2). The present definition is of major significance because "avoided costs" are the statutory base line for purposes of determining the "incremental costs" to be recovered through the REPS Rider. More specifically, in pertinent part, Senate Bill 3 requires that the Commission allow an electric power supplier to recover all reasonable and prudent costs incurred in complying with the REPS provisions of the statutes, i.e., in particular, with regard to the provisions of G.S. 62-133.7(b), (c), (d), (e) and (f), that are in excess of the electric power supplier's "avoided costs."

Progress, in its comments, and the Public Staff, in its reply comments, advocated certain changes to the definition of "avoided cost rates." Those changes are discussed below.

CPV and NCSEA, in their reply comments, objected to Progress's and the Public Staff's proposal to require that the avoided cost value used to calculate program costs remain fixed for the duration of any long-term contract for renewable energy supply at the value at the time the contract was executed (Progress) or at the time the first energy delivery under the contract occurred (Public Staff). In particular, CPV proposed that "the calculation of avoided costs … be done on the basis of the avoided cost calculated for each year of the contract as it goes forward."

In their reply comments, ED, SACE and SELC agreed with the Public Staff's position, as stated in the Public Staff's initial comments, that the avoided costs for long-term purchases should be determined as of the date the power is first delivered under the contract.[4]

In their reply comments, CIGFUR and CUCA supported Progress's proposal that "avoided costs" be fixed at the time the contract for the purchase and sale of renewable energy was entered into.

Progress's proposal, which is presented below, involves the inclusion of additional language. The additional language is denoted by underlining:

> (2) "Avoided cost rates" shall be defined as an electric power supplier's most recently approved or established avoided cost rates in North

[4] As explained subsequently, the Public Staff, in its reply comments, stated that it was willing to agree with Progress that the avoided costs for long-term purchases should be determined as of the date the contract is executed rather than as of the date of first delivery under the contract. ED, SACE and SELC's agreement with the Public Staff's initial comments in this regard was "on the grounds that such a definition is necessary to avoid ambiguity and uncertainty in the proposed rules." Therefore, it would appear that they would not object to the position taken by the Public Staff in its reply comments.

Carolina for purchases of electricity from qualifying facilities pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978. For the purpose of determining incremental costs and avoided costs to be recovered pursuant to Rules R8-55 and R8-67, avoided cost for long-term purchase power agreements with renewable energy facilities and new renewable energy facilities over the term of the agreement shall be the annual non-levelized avoided cost utilized in the most recent avoided cost proceeding at the time the purchase power agreement is entered into and shall remain fixed at those levels for the life of that agreement. [Endnote omitted.]

In the endnote omitted above, Progress stated that avoided costs, over the term of long-term purchase agreements, must be established up front to facilitate development of a long-term REPS compliance plan and compliance with the cost cap in G.S. 62-133.7(h)(4). Under Progress's proposed definition, "avoided costs" would be the "non-levelized avoided cost utilized in the most recent avoided cost proceeding at the time the purchase power agreement is entered into and [would] remain at those levels for the life of that agreement."

The Public Staff's proposed changes to the definition of "avoided costs rates" are presented below. Deletions are presented in a strikethrough format. Additions are denoted by underlining:

(2) "Avoided cost rates" mean ~~shall be defined as~~ an electric power supplier's most recently approved or established avoided cost rates in North Carolina for purchases of electricity from qualifying facilities pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978, except that with respect to renewable energy purchased by an electric public utility under a multi-year contract with a renewable energy facility that is registered under Rule R8-66, "avoided cost rates" mean the electric public utility's most recently approved or established avoided cost rates in North Carolina for purchases of electricity from qualifying facilities pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 as of the date that such contract is executed.

Under the Public Staff's proposed definition, assuming its proposed exception would apply,[5] "avoided costs" for purposes of determining the REPS rider would be "an electric power supplier's most recently approved or established avoided cost rates ... as of the date that [the contract] is executed." If the Public Staff's exception does not apply, the date of the "avoided cost rates" to be used for this purpose is not entirely clear, if based solely upon the Public Staff's proposed definition. However, if the Public Staff's

[5] As provided in its definition, the Public Staff's exception becomes operative if the renewable energy facility from which the energy is to be purchased is registered under proposed Rule R8-66.

comments presented below and its proposed Rule R8-67(d)(1) are considered in conjunction with its definition of "avoided cost rates," it would appear that, under the Public Staff's definition, "avoided costs" are to be based on "avoided cost rates" as of the date the contract is executed, the exception provision contained in the Public Staff's definition to the contrary notwithstanding. In its reply comments, the Public Staff stated as follows:

> [Progress] proposed in its initial comments that instead of the date when power is first delivered [under the contract as proposed by the Public Staff in its initial comments] the avoided costs for long-term purchases should be determined as of the date the contract is executed. <u>The Public Staff is willing to agree to [Progress's] position on this matter.</u> However, in further discussions with [Progress] and other utilities, the Public Staff realized that its initial comments had left other important questions unanswered. In its biennial avoided cost proceedings, the Commission establishes levelized avoided cost energy rates for 5-year, 10-year and 15-year contracts between utilities and QFs, as well as a variable avoided cost rate for spot energy purchases. The Commission-approved rates may vary depending on the QF's energy source, or on whether the QF delivers power to the utility's distribution or transmission system. If the purchase contract between a utility and a renewable energy supplier closely matches one of the standard QF contracts, with respect to its duration and other relevant factors, the avoided cost component of the purchase price can be determined directly from the provisions of the Commission-approved QF contract; and the incremental cost component, of course, is simply what remains after subtracting the avoided cost component from the bundled purchase price. If, however, the bundled renewable energy purchase contract is not for a spot purchase or for a term of 5, 10, or 15 years - or if the purchaser is not a utility whose avoided cost rates are fixed by the Commission – there is no quick and easy way to determine the avoided cost component. In that event, the Public Staff believes that the parties should be required to make a good faith estimate of the avoided cost and incremental cost components of the purchase price and specify them in the contract. Normally the parties' breakdown of the two components of the purchase price will be controlling, but if it is clearly not made in good faith – if the avoided cost component specified in the contract is obviously different from the purchaser's actual avoided costs – then the Commission will have to make its own determination of the avoided cost and incremental cost components. <u>The Public Staff has revised its proposed language for Rules R8-67(a)(2) and (d)(1) to reflect this approach.</u> [Emphasis added.]

After revision, the Public Staff's proposed language for the new subsection (d)(1), "Contracts to purchase renewable energy," reads as follows:

> (1) Whenever an electric power supplier purchases energy that is eligible for REPS Credits, the contract between the electric power supplier

> and the seller shall specify the avoided cost and incremental cost components of the purchase price. 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 duration as the contract between the electric power supplier and the seller, that rate shall be used as the avoided cost component. In all other cases, the avoided cost component shall be a good faith estimate of the electric power supplier's avoided cost, levelized over the duration of the contract. The incremental cost component shall be equal to the total purchase price minus the avoided cost component. [Emphasis added.]

The underlined language above, in effect, is a definition of "avoided costs." As indicated by the Public Staff, such language is significantly more explicit and precise than that contained in its initial comments. However, the language in question was not incorporated into the Public Staff's revised definition of "avoided cost rates," per se.

CPV argued, in essence, that fixing the avoided costs at the levels in effect as of the date the contract was executed as proposed by Progress and the Public Staff would be inappropriate because such an approach:

- Ignores the value of non-fuel based renewables, such as wind and solar systems, as a hedge against fossil fuel cost increases and future carbon emission control costs;
- Exaggerates the cost of implementing the REPS by ignoring the increase in future avoided costs in the calculation of program costs; and
- Stands in sharp contrast to the proposed practice under utility recovery of "net lost revenues" from energy efficiency programs, which use detailed avoided cost data.

NCSEA disagreed with Progress's and the Public Staff's approach, contending that such an approach fails to consider potential increases in fossil fuel costs and costs associated with carbon emission management. According to NCSEA, an increase in fuel costs or potential carbon emission requirements could raise the avoided cost above the avoided cost fixed in a renewable energy contract. NCSEA stated that, with contracts fixed for the life of the agreement, this situation would result in inflated costs being attributed to the REPS cost cap. NCSEA averred that, to prevent this scenario, the avoided cost should be updated on an annual basis.

Regarding Progress's proposed definition, the Commission is of the opinion that it would be inappropriate to adopt that definition of "avoided cost rates," as presented, because, under Progress's definition, "non-levelized avoided costs" would be used throughout the life of a renewables contract without regard to the contract's duration. Such use of "non-levelized avoided costs" would be inconsistent with the levelized avoided cost energy rates prescribed for use by the Commission in its biennial avoided cost proceedings for 5-year, 10-year and 15-year contracts between utilities and QFs.

Additionally, the precise meaning of the term "utilized" in the second sentence of Progress's definition is not entirely clear.

Regarding the arguments advanced by CPV and NCSEA, the Commission is of the opinion, and so finds and concludes, that the concerns which they have expressed do not outweigh the need, as expressed by Progress, for up-front establishment of avoided costs, over the term of long-term purchase agreements, to facilitate development of a long-term REPS compliance plan and compliance with G.S. 62-133.7(h)(4).

The Public Staff's definition of "avoided cost rates," in general, appears to be entirely consistent with the rates prescribed for use by the Commission in its biennial avoided cost proceedings. However, the Public Staff's definition, standing alone, is somewhat inexact, i.e., unless it is considered in conjunction with the Public Staff's proposed Rule R8-67(d)(1). In fact, as noted above, much of the Public Staff's proposed language in (d)(1), in effect, is a definition of "avoided costs." Thus, the Public Staff, in essence, has proposed two definitions of "avoided cost rates," i.e., once in subsection (a)(2) and again in subsection (d)(1). The Commission is, therefore, of the opinion that it should not adopt the duplicative language proposed by the Public Staff to be included in subsection (d)(1).

The Commission, therefore, concludes that it should adopt the following definition of "avoided cost rates" in subsection (a)(2) for purposes of this proceeding:

> "Avoided cost rates" means an electric power supplier's most recently approved or established avoided cost rates in North Carolina, as of the date the contract is executed, for purchases of electricity from qualifying facilities pursuant to the provisions of 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 such a 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; provided, however, that development of such estimates of avoided cost by an electric public utility shall include consideration of the avoided cost rates then in effect as established by the Commission. Determinations of avoided costs, including estimates thereof, shall be subject to continuing Commission oversight and, if necessary, modification should circumstances so require.

The foregoing definition of "avoided cost rates" will allow the avoided cost, over the term of long-term purchase agreements, to be established up front with reasonable certainty to the maximum extent practicable. Such a result is appropriate from the standpoint of facilitating the development of long-term compliance plans and compliance with G.S. 62-133.7(h)(4).

ISSUE 25. Definition of "REPS Credits"

Proposed Rule R8-67(a)(3) defines "REPS Credits" as:

> credits claimed by an electric public utility, electric membership corporation, or municipal electric supplier from eligible sources pursuant to G.S. 62-133.7(b)(2) or (c)(2). Eligible sources include electric power or associated renewable energy certificates derived from renewable energy resources on or after January 1, 2008; reduced energy consumption through the implementation of energy efficiency measures on or after August 20, 2007; and, for electric membership corporations and municipal electric suppliers, reduced energy consumption through the implementation of demand-side management on or after August 20, 2007.

In its initial comments, the Public Staff proposed to amend the definition of "REPS Credits" to distinguish between the "eligible sources" for REPS compliance by electric public utilities, municipal electric suppliers and electric membership corporations. As modified in its reply comments to address concerns raised by CIGFUR, ElectriCities and NCEMC, the Public Staff's amended rule provides, in part, as follows:

> Eligible sources include:
>
> (i) For electric public utilities, electric power or associated renewable energy certificates derived from new renewable energy facilities on or after January 1, 2008; electric power generated on or after January 1, 2008, through the use of a renewable energy resource at a generating facility other than the generation of waste heat derived from the combustion of fossil fuel; and measurable reduced energy consumption through the implementation of energy efficiency measures on or after August 20, 2007; and
>
> (ii) For electric membership corporations and municipal electric suppliers, electric power or associated renewable energy certificates derived from new renewable energy facilities on or after January 1, 2008; electric power or associated renewable energy certificates purchased on or after January 1, 2008 from renewable energy facilities; electric power purchased on or after January 1, 2008 from hydroelectric power facilities; electric power acquired through a wholesale purchase power agreement with a wholesale supplier of electric power whose portfolio of supply and demand options meets the requirements of G.S. 62-133.7; and measurable reduced energy consumption through the implementation of

energy efficiency measures or demand-side management on or after August 20, 2007.

In its reply comments, NCSEA agreed with CIGFUR that "REPS Credits," defined in Rule R8-67(a)(3) as credits claimed by an electric service provider from an eligible source for renewable energy or reduced energy consumption, is very vague. In its initial comments, NCSEA argued that "[RECs] provide a basis for monitoring and compliance of REPS." NCSEA noted that the definition of REC in G.S. 62-133.7(a)(6) provides that RECs are "used to track and verify compliance" with REPS.

NCSEA further argued that the structure and content of Senate Bill 3 hinges on the renewable energy facility owner having ownership of the RECs associated with the power generated by that facility. The clear intent of the legislation is a REC-based accounting system, where a public utility purchases RECs from a renewable energy facility owner and uses them to comply with the REPS requirement. The utility must then retire RECs to count them toward compliance with that requirement. The structure of the cost cap also relies on a REC-based accounting system, where a public utility seeks cost recovery for the RECs purchased from the renewable energy facility owner. Therefore, NCSEA recommended:

- That the REPS should rely on REC-based accounting, whether a utility contracts solely for RECs or both renewable electricity and the associated RECs; and
- That all RECs are created by, and therefore belong to, the renewable energy generator until purchased through a contract by an electric service provider for use in compliance with Senate Bill 3 or by another party for some other purpose.

SunEdison and Solar Alliance proposed that RECs "will be used to comply" with REPS and implied that they would have all forms of REPS compliance converted into RECs and tracked via a REC tracking system.

Consistent with the decision to eventually implement a REC tracking system, the Commission concludes that the non-statutory term "REPS Credit" should be discarded. Rather, as recommended by a number of parties, REPS compliance should be based, to the extent possible, solely on RECs.

The term "REPS Credits" was originally proposed as a proxy for RECs because the rules proposed did not call for a REC tracking system. However, it is difficult to craft a precise definition of "REPS Credits," as demonstrated by both the originally proposed definition and that suggested by the Public Staff. This fact serves to highlight the potential pitfalls of restating the statutory standards of G.S. 62-133.7(b)(2) and (c)(2).

The definition of REC is broad enough to encompass nearly all of the means of REPS compliance enumerated in G.S. 62-133.7(b)(2) and (c)(2). The exception, as noted by ElectriCities and NCEMC, is the provision in G.S. 62-133.7(c)(2)b authorizing municipalities and cooperatives to "[r]educe energy consumption through the implementation of demand-side management ... measures." Otherwise, REPS compliance may be determined by tracking RECs associated with (1) generation at utility-owned facilities, G.S. 62-133.7(b)(2)a, (b)(2)b, (c)(2)a; (2) reduced energy consumption through the implementation of EE measures, G.S. 62-133.7(b)(2)c, (c)(2)b; and (3) generation at nonutility-owned facilities, including CHP systems and solar thermal energy facilities, G.S. 62-133.7(b)(2)d, (b)(2)e, (c)(2)c, (c)(2)d.

Embodied in the definition of "REPS Credits," however, was the requirement that only RECs associated with renewable energy produced after the effective date of the REPS statute, G.S. 62-133.7, be eligible for use by an electric power supplier to comply with the REPS requirement. Such a limitation is required only because existing facilities were grandfathered under the statute. The statute's purpose of facilitating continued generation from existing renewable energy facilities and the development of new renewable energy facilities would be frustrated if an electric power supplier were able to use RECs associated with generation from a grandfathered facility that was produced months or years before enactment of the REPS mandate for compliance purposes. Therefore, only RECs associated with renewable energy produced after the effective date of the REPS statute, January 1, 2008, were proposed to be allowed to be used for REPS compliance. For RECs associated with reduced energy consumption through the implementation of an energy efficiency measure, the definition of "REPS Credits" established a starting date consistent with the effective date of G.S. 62-133.8.

In their comments, ElectriCities and NCEMC argued that the date should be changed to January 1, 2007, consistent with the in-service dates for new renewable energy facilities, G.S. 62-133.7(a)(5), and the implementation dates for new energy efficiency measures, G.S. 62-133.8(a). In addition, they argued that January 1, 2007, would also be a reasonable date with regard to reduced energy consumption through the implementation of demand-side management programs even though G.S. 133-7(c) allows municipalities and cooperatives to use demand-side management activities to meet the REPS mandate regardless of when the activities were implemented.

As set out above, the Public Staff proposed to amend the definition of "REPS Credits," in part, to address this issue. Thus, the Public Staff supported the use of January 1, 2008, for RECs associated with renewable energy and August 20, 2007, for reduced energy consumption through the implementation of EE or DSM measures.

In its comments, Small Hydro also supported the inclusion of January 1, 2008, as the date after which RECs must be earned to be eligible for use by an electric power supplier to comply with the REPS.

In deleting the definition of "REPS Credits," the Commission concludes that Rule R8-67(b)(4) and (5) should be modified to retain the limitation on the initial dates for REC eligibility found in that definition. In addition, after further consideration, the Commission concludes that the date applicable to reduced energy consumption through the implementation of DSM and EE measures for all electric power suppliers should be changed to January 1, 2008, consistent with the effective date of the REPS statute rather than with the date for which cost recovery would be allowed for new energy efficiency measures pursuant to G.S. 62-133.8.

ISSUE 26. Expiration of RECs

NCSEA stated that G.S. 62-133.7(h) allows electric power suppliers to recover the incremental costs incurred to purchase RECs to comply with the REPS. Electric public utilities should be able to recover costs incurred for RECs that have been retired toward compliance. RECs, however, should have an expiration date after which they no longer can be counted for compliance. NCSEA noted that most states have chosen a life of 3 years from the quarter of the year in which the RECs were generated. Senate Bill 3 does not address the life of a REC, noting only that RECs in excess of compliance in a particular year can be sold by an electric service provider. However, if a REC has an unlimited life, generated from either in-state or out-of-state, then it could be retired to meet compliance in North Carolina many years after it was generated. NCSEA argued that this was not the intent of Senate Bill 3. Prior to 2012, however, electric public utilities should be able to acquire and retire RECs for compliance in 2012.

Progress, Duke and Dominion asserted that Rule R8-67 should explicitly provide (1) that REPS credits and associated RECs do not expire and may be carried forward for use in compliance in future years and (2) that costs may similarly be carried forward for recovery in future years. They argued that the utility has no control over the amount of energy it will receive on its system from renewable resources under contract because solar and wind are not dispatchable.

The Public Staff noted that:

> One of the most complex issues associated with implementation of the REPS involves providing for the “ramp-up” period prior to the initial application of the 3% REPS requirement in 2012; determining the extent to which electric power suppliers will be allowed to acquire REPS Credits in one year and “bank” them, so that they can be used for compliance with the REPS in a subsequent year; and determining the extent to which utilities will be allowed to incur incremental costs in the test period for one REPS rider proceeding and carry those costs over for recovery in a subsequent proceeding. Clearly, as they prepare for the imposition of the 3% REPS requirement in 2012, the utilities and other electric power suppliers will need to enter into contracts to purchase renewable energy in 2008-11; and they will need to take delivery of some renewable energy (or acquire RECs) during this period, since the renewable energy facilities cannot be expected to remain idle until January 1, 2012 and begin full operation that day.

The Public Staff proposed that REPS Credits will not expire until December 31 of the second calendar year after the associated electric energy is generated, and they be banked until their expiration.

The Commission agrees that the policy goal of Senate Bill 3 of encouraging the development of new renewable energy and EE would be frustrated by the ability to offer RECs for sale to electric power suppliers many years after the related power was generated. A market flush with “stale” RECs would actually hinder the development of renewable energy resources. Therefore, similar to the approach taken in many other states, the Commission concludes that Rule R8-67(b) should be revised to provide that RECs expire three years after their creation unless sold within that time to an electric power supplier for REPS compliance.

ISSUE 27. Definition of “customer account” and “year-end number of customer accounts”

G.S. 62-133.7(h) imposes a cap on the incremental costs associated with REPS compliance and calculates the cap based upon “the electric power supplier’s total number of customer accounts determined as of 31 December of the previous calendar year.” Proposed Rule R8-67(a)(4) defines “year-end number of customer accounts” as identical to the way that term is used for reporting to the Energy Information Administration (EIA), United States Department of Energy.

In its initial comments, the Public Staff stated its belief that to apply the cost caps in Senate Bill 3 on the REPS rider, the Commission must define precisely what constitutes a “customer account.” The Public Staff proposed that this term be given the same meaning as in the utilities’ reports to the EIA. Although the Public Staff originally believed that in these reports a “customer account” was essentially equivalent to a meter, the Public Staff stated in its reply comments that it had learned that there is no generally accepted definition of “customer account” for EIA reporting purposes and that utilities define the term differently in preparing their reports. Therefore, the Public Staff revised its proposed definitions of “customer account” and “year-end number of customer accounts” to state more specifically that a customer account means a meter used for measuring electric energy delivered by an electric power supplier to a customer. The revised definition takes into account totalization arrangements, under which multiple meters are grouped into a single account, and it gives suppliers authority to reject requests from customers for new totalization arrangements designed to reduce the customer’s per-account ceiling and not for legitimate business purposes.

NCFB proposed that, for purposes of the per-account recovery of incremental costs of renewable purchases, “customer account” be defined as one customer at a single location rather than a single meter. CIGFUR agreed that this was a reasonable construction of the statute and asserted that the instructions for Form EIA-861 support this construction.

CUCA stated that, if “year-end number of customer accounts,” as that term is defined for purposes of EIA reporting, refers to an account as an individual residential customer in a single location rather than the number of meters serving that single location, the same definition should apply to commercial and industrial customers. CUCA argued that this interpretation would also be consistent with the EIA definition of an “account” for purposes of street lighting, for which the EIA defines the customer account as the community, not each separate meter used in providing street lighting. If, however, the Commission wishes to adopt a rule that allows each commercial and industrial meter to be defined as a customer account, even if two or more meters are serving a single commercial or industrial location, then CUCA argued that allowing each electric power supplier the discretion to define "customer accounts" in a manner that recognizes the unique arrangements and needs of its customers would be a more equitable rule. Each utility's discretion in this respect would of course remain subject to a reasonableness standard and the oversight of the Commission. In its reply comments, CUCA stated that it opposed proposals to "define accounts in a manner consistent with EIA reporting requirements."

Duke argued that the interpretation of the "per-account" provision should be made on a utility-by-utility basis rather than on the basis of a blanket determination for all utilities. Duke stated that subsection (b)(6) allows for a utility-specific approach. Duke is concerned that, to the extent that the utility proposes a methodology for interpreting "per-account" that differs from its annual EIA report, there is the potential for conflict between the total amount to be collected from customers under the utility's proposed methodology and the annual aggregate amount calculated under G.S 62-133.7(h)(3) using the definition proposed in Rule R8-67(a)(4). Duke urged the Commission to resolve this potential conflict in a manner that ensures the utility may propose a methodology that is fair to its customers based upon its tariff classes.

In their reply comments, Duke, Progress and Dominion proposed, in order to address any potential unintended and inequitable impacts in applying the per customer account caps set forth in G.S. 62-133.7(h), that Rule R8-67(a)(3) be amended to provide that the Commission may exclude certain low usage account types or treat certain low usage account types as residential customer accounts based upon specific circumstances presented by a utility in its REPS compliance plan.

The per-account charges adopted by the General Assembly in G.S. 62-133.7(h)(4) were derived based upon the number of "customer accounts" reported by the electric power suppliers to the EIA. Adopting a different definition of "customer account," such as that suggested by NCFB and CIGFUR, could reduce the number of accounts and the total incremental costs that may be used to purchase renewable energy under the REPS. The Commission is mindful, however, of the potential burden, particularly on residential and small commercial customers that might have additional meters on wells, area lighting and other relatively small loads. Lastly, the Commission appreciates the fairness concerns implicitly raised by CUCA, which suggests that "customer accounts" be consistently determined across electric suppliers.

For electric public utilities, the Commission believes that the rules as originally proposed appropriately balance these interests. The definition of "year-end number of customer accounts" in Rule R8-67(a)(4) assumes that, unless otherwise approved by the Commission, the electric public utilities will determine customer accounts in the same manner as that information is reported to the EIA. Proposed Rule R8-67(b)(6), however, provides an opportunity for an electric public utility to propose an alternative methodology for the assessment of per-account charges, subject to Commission approval. This could include the exclusion of certain low usage accounts, as suggested by the utilities in their comments. Under proposed Rule R8-67(b)(6),

> In each electric public utility's first-filed REPS compliance plan, the electric public utility shall propose a methodology for the assessment of the per-account charges to recover the cost of complying with the requirements of G.S. 62-133.7(b), (d), (e) and (f). The proposed methodology may be specific to each electric public utility, shall be based upon a fair and reasonable allocation of costs, and shall be consistent with G.S. 62-133.7(h)(4). The electric public utility may seek to amend the methodology approved by the Commission in subsequent compliance plan filings.

The Commission, therefore, consistent with other revisions adopted herein that would redesignate subsection (b)(6) as (c)(4), concludes that the definition of "year-end number of customer accounts" in Rule R8-67(a) should be clarified, as follows:

> "Year-end number of customer accounts" ~~shall be defined as~~ <u>means</u> the number of accounts within each customer class as of December 31 ~~of~~ <u>for</u> a <u>given</u> calendar year and<u>, unless approved otherwise by the Commission pursuant to subsection (c)(4),</u> determined in the same manner as that <u>information</u> is reported to the Energy Information Administration (EIA), United States Department of Energy, for annual electric sales and revenues reporting.

Although the rates and cost recovery for other electric power suppliers are not approved by the Commission, these entities are subject to the Commission's jurisdiction with regard to REPS compliance and the limit on total incremental costs pursuant to G.S. 62-133.7(h)(4). Any proposed deviation in the determination of customer accounts for these electric power suppliers would also be subject to Commission approval.

ISSUE 28. Per-account charges as individual account maximums

Proposed Rule R8-67(c)(9) provides that the total incremental costs to be recovered by a utility in any calendar year for REPS compliance may not exceed the cap determined using the per-account charges set forth in G.S. 62-133.7(h)(4).

In order to ensure that the per-account ceilings provided for in Senate Bill 3 are not exceeded for any particular customer account, the Public Staff proposed in its initial comments to add the following sentence to subsection (c)(9):

> Each electric public utility shall ensure that the incremental costs recovered under the REPS rider and REPS EMF rider during the cost recovery period from any given customer account do not exceed the applicable per-account charges set forth in G.S. 62-133.7(h)(4).

In its reply comments, Nucor supported the Public Staff's proposed language, stating that it will make clear that the per-account REPS ceilings of Senate Bill 3 apply not only to a utility's entire body of customer accounts but also to each specific customer account.

The Commission agrees that the per-account caps apply to both the total incremental costs and the amount that may be recovered from any individual account and, therefore, concludes that Rule R8-67(c)(9) should be revised as proposed by the Public Staff.

ISSUE 29. Definition of "biomass"

G.S. 62-133.7(a)(8) defines "renewable energy resource," in part, as follows: "a biomass resource, including agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases, energy crops, or landfill methane." Proposed Rule R8-67 only references the statutory definition and does not further define "biomass."

In its comments, Bio-Energy described its waste-to-energy conversion process and requested that the Commission "specifically identify municipal solid waste and refuse derived fuel within the meaning of 'renewable energy resource.'" No party commented on Bio-Energy's request.

The Commission concludes that a determination of whether a resource used by a particular facility is a "renewable energy resource," such as that requested by Bio-Energy in this proceeding, should be made on a case-by-case basis with an adequate opportunity for the Public Staff or other interested persons to challenge asserted facts. The registration process established in Rule R8-66 permits such a determination to be made on the basis of an appropriate record with regard to a particular facility. Alternatively, the owner of a facility could seek a declaratory ruling from the Commission that the facility qualifies as a renewable energy facility or a new renewable energy facility. Therefore, rather than potentially limit the definition of "biomass" on the basis of an incomplete record in this rulemaking proceeding, the Commission concludes that the statutory definition of "renewable energy resource" is sufficient and that "biomass" should not be separately defined in Rule R8-67.

ISSUE 30. Definition of "renewable energy facility" and "new renewable energy facility"

G.S. 62-133.7(a)(5) and (a)(7) define "new renewable energy facility" and "renewable energy facility" as follows:

> (5) 'New renewable energy facility' means a renewable energy facility that either:
>
> a. Was placed into service on or after 1 January 2007.

b. Delivers or has delivered electric power to an electric power supplier pursuant to a contract with NC GreenPower Corporation that was entered into prior to 1 January 2007.

c. Is a hydroelectric power facility with a generation capacity of 10 megawatts or less that delivers electric power to an electric power supplier.

(7) 'Renewable energy facility' means a facility, other than a hydroelectric power facility with a generation capacity of more than 10 megawatts, that either:

a. Generates electric power by the use of a renewable energy resource.

b. Generates useful, measurable combined heat and power derived from a renewable resource.

c. Is a solar thermal energy facility.

As proposed, Rule R8-67 incorporates these statutory definitions by reference.

The Public Staff took the position that the Commission will need the ability to distinguish between RECs from "new" renewable energy facilities, which public utilities can use to comply with the REPS requirement, and those from other renewable energy facilities, which electric membership corporations and municipalities can use to comply with REPS. The Public Staff proposed to modify R8-66 to make this distinction by requiring the Chief Clerk to adopt two separate registration numbering systems to differentiate between the two types of facilities. The Public Staff recommended adding the following definitions to Rule R8-67 to specify that facilities must be registered with the Commission to be counted toward REPS compliance:

(6) "New renewable energy facility" means a renewable energy facility that <u>is either owned directly by an electric public utility or is registered under Rule R8-66(c)</u>, and either:

(i) Was placed into service on or after January 1, 2007;

(ii) Delivers or has delivered electric power to an electric power supplier pursuant to a contract with NC GreenPower Corporation that was entered into prior to January 1, 2007; or

(iii) Is a hydroelectric power facility with a generation capacity of 10 megawatts or less that delivers electric power to an electric power supplier.

(7) "Renewable energy facility" means a facility, other than a hydroelectric power facility with a generation capacity of more than 10 megawatts, that <u>either is owned directly by an electric public utility or is registered under Rule R8-66(c)</u>, and either:

(i) Generates electric power by the use of a renewable energy resource;

(ii) Generates useful, measurable combined heat and power derived from a renewable energy resource; or

(iii) Is a solar thermal energy facility.

ElectriCities and NCEMC noted that the definition of “renewable energy facility” in Senate Bill 3 is distinctly different from the definition of “new renewable energy facility.” The “new renewable energy facility” requirement applies to public utilities but does not apply to cooperatives and municipalities. The Public Staff’s initial proposal to extend the definition of new renewable resources in the definition of “REPS Credits” inappropriately precludes the use of existing renewable resources or energy facilities by cooperatives and municipalities for REPS compliance. Similarly, cooperatives and municipalities can use RECs from “renewable energy facilities” to comply with REPS because there is no requirement that they comply via “new” facilities. In contrast, RECs used by public utilities must be from “new” renewable energy facilities.

While the distinction between a “renewable energy facility” and a “new renewable energy facility” is important, as noted by the parties, the Commission concludes that the burden is on each electric power supplier to demonstrate that RECs they use for REPS compliance are from an appropriate source. It might be helpful, however, for a REC tracking system to differentiate between RECs from renewable energy facilities and “new” renewable energy facilities. The Commission concludes, however, that the statutory definitions of “renewable energy facility” and “new renewable energy facility” are sufficient and that the terms should not be redefined in Rule R8-67.

ISSUE 31. Definition of “renewable energy certificate”

G.S. 62-133.7(a)(6) defines “renewable energy certificate” as:

> a tradable instrument that is equal to one megawatt-hour of electricity or equivalent energy supplied by a renewable energy facility, new renewable energy facility, or reduced by implementation of an energy efficiency measure that is used to track and verify compliance with the requirements of this section as determined by the Commission. A ‘renewable energy certificate’ does not include the related emission reductions, including, but not limited to, reductions of sulfur dioxide, oxides of nitrogen, mercury, or carbon dioxide.

Wal-Mart took the position that self-implementation of EE measures by an electric consumer will create RECs that can be used by an electric utility to meet its REPS requirement. It proposed that self-directed DSM should also be eligible for RECs.

Similarly, Nucor argued that “the rules should allow self-directed DSM to generate renewable energy certificates in the same way as self-directed energy efficiency measures.” Nucor maintained that DSM is an ideal and cost-effective resource for meeting REPS. Allowing self-directed DSM to generate RECs that can be used by the utilities to meet the REPS requirement will make it much easier for the utilities to meet that requirement at a reasonable cost while preserving the goal of reducing negative environmental impacts.

The Public Staff proposed to only reference the statutory definition of an REC.

As noted above, the statutory definition of an REC includes "electricity or equivalent energy ... reduced by implementation of an energy efficiency measure." The Commission concludes that the definition of an REC should not be expanded by Commission rule to include DSM, which is not included in the statutory definition. Moreover, while the definition of an REC includes energy efficiency, it is G.S. 62-133.7(b)(2) and (c)(2) that control which RECs may be used by an electric power supplier for REPS compliance. Neither subsection (b)(2) nor (c)(2) provide for the purchase of RECs associated with the implementation of EE or DSM measures.

ISSUE 32. Definition of "Incremental costs"

In its initial comments, the Public Staff recommended defining "incremental costs" in Rule R8-67(a). The definition would track the statutory definition in G.S. 62-133.7(h)(1) and add "'Incremental costs' do not include the costs of an energy efficiency measure, except to the extent that those costs are incurred for the purchase of electric power."

The Public Staff argued that the typical costs of EE programs should be recovered in the DSM/EE rider rather than through the REPS rider. This approach will allow utilities to recover EE costs without being constrained by the per-account ceiling on the REPS rider, and it will also allow a larger amount of renewable energy to be supported by the REPS rider.

ElectriCities and NCEMC opposed the Public Staff's proposal to the extent it would be applied to municipalities and electric membership corporations. They argued that, because they are not subject to the DSM and EE cost recovery provisions of G.S. 62-133.8, the Public Staff's proposed change to the definition would prohibit them from recovering the costs of their EE programs. Therefore, the modification should be clarified so that it applies only to electric public utilities.

CUCA and CIGFUR argued that the Public Staff's proposed exclusion of EE costs is inconsistent with Senate Bill 3, which defines the term to include all reasonable and prudent costs in excess of the avoided costs incurred to comply with the REPS requirement. They argued that allowing EE costs to be recovered without being subject to the incremental cost cap is contrary to the plain language of the statute and subverts the finely crafted balance achieved in the development of the legislation.

In its initial comments, NCSEA stated that, under Senate Bill 3, "the cost of energy efficiency measures does not fall under the cost cap."

As noted above, Senate Bill 3 provides a detailed definition of "incremental costs." While it is possible, as argued by the Public Staff and NCSEA, that costs of EE measures, which are required under G.S. 62-133.8(b) to be cost-effective, should be less than the utility's avoided costs, the Commission concludes that it is not appropriate to prejudge any proposals for DSM/EE cost recovery by adopting a definition of "incremental costs" that is more restrictive than that provided in Senate Bill 3. The Commission, therefore, concludes that "incremental costs" should not be defined in Rule R8-67 as proposed by the Public Staff.

ISSUE 33. Review and approval of compliance plans

Proposed Rule R8-67(b) requires all electric power suppliers to file an annual REPS compliance plan with the Commission. This plan requires the provision of information regarding the electric power supplier's forecasted retail sales, REPS requirement and plans to meet that requirement akin to current least cost integrated resource planning (IRP). Although subsection (b)(4) provided that the Commission "may schedule a public hearing to receive public comments or expert testimony regarding any REPS compliance plan," the rule does not require the Commission to "approve" the plan.

The Public Staff stated that it initially proposed that compliance plans be informational only, with no requirement that the Commission approve them, but that a number of parties have indicated that compliance plans should be subject to Commission approval. In its reply comments, the Public Staff stated that it had discussed this issue with the utilities and believes that consensus has been reached for language that would provide that the Commission may approve a compliance plan, but that approval will not constitute approval of the recovery of costs associated with the plan or a determination that the supplier has complied with REPS. Comparable to approval of a utility's IRP, approval of an REPS compliance plan will reflect the Commission's overall approval of the utility's planning process, but it will not preclude further review of any specific project or activity in the plan. Hence, the Public Staff proposed to add a procedure in Rule R8-67(b)(1)(ii) for Commission review and approval of annual compliance plans:

(ii) Compliance plan review and approval:

(a) Within 90 days after the filing of each electric power supplier's compliance plan, the Commission shall review the reasonableness of the plan for purposes of complying with G.S. 62-133.7(b), (c), (d), (e), and (f). The Commission may require the electric power supplier to refile its plan if it does not contain all the required information; may direct the electric power supplier to answer questions on its plan; or may direct an electric power supplier representative to appear for questioning about the plan.

(b) Within 30 days after the filing of the plan, any interested party may file comments on the plan.

(c) The Commission shall issue an order within 90 days either disapproving the plan, requiring modifications to the plan, or approving the plan as reasonable for purposes for complying with G.S. 62-133.7(b), (c), (d), (e), and (f). Approval of the compliance plan, however, shall not constitute an approval of the recovery of costs associated with the plan or a determination that the electric power supplier has complied with G.S. 62-133.7(b), (c), (d), (e), and (f).

Duke, Progress and Dominion agreed with the Public Staff's position and urged that the rule be modified to provide for Commission approval of the compliance plans. In their reply comments, the utilities set forth a number of reasons why approval is necessary.

The utilities argued that Commission review and approval of the REPS compliance plans is a necessary element of the Commission's rules. As a part of the IRP and CPCN processes, the Commission determines whether the utilities' plans are consistent with the requirements Chapter 62, the policy goals of the State, and, ultimately, the public interest before the utility may proceed with generation additions. Similarly, the utilities recommend that the Commission review and approve the utilities' REPS compliance plans to provide essential guidance and oversight in the interpretation and implementation of the new resource requirements embodied in the REPS before the utilities are required to make significant investments and demonstrate compliance. Given that these requirements are new, there may be questions as to the proper interpretation of G.S. 62-133.7, the rules ultimately adopted as a result of this proceeding, or issues that are not clearly addressed by the statute and rules. The REPS compliance plan approval process provides the opportunity to address such questions before the utilities implement their plans.

The utilities further argued that they should not be required to assume all of the risk associated with new long-term contracts. These contracts will differ from traditional generation purchased power contracts in several important regards. At the time the utilities enter into these contracts they will have no special or unique information regarding the cost or viability of the renewable generators or the availability of other sources of renewable generation that is not available to all other interested parties. Thus, it is appropriate for parties and the Commission to express concerns about such contracts, and the REPS compliance plans in general, at the beginning of the process. The utilities argued that an additional reason for the Commission to approve the compliance plans is that there is no way to know for certain how much a utility should agree to pay a renewable generator. Because the utilities do not know how much above avoided cost they can prudently pay to purchase renewable energy or whether the Commission will approve the incurrence of such costs, it makes sense for the Commission to review and approve the utilities' compliance plans at the beginning of the process.

The utilities noted that other differences between traditional power supply agreements and the purchase of renewable energy include the requirement to procure a specific amount of renewable energy and the establishment of spending caps, requiring the utilities to balance the compliance standard against the cap. For example, it is unclear whether the utilities' first obligation is to achieve the carve-out obligations, which may result in utilities hitting the caps well before the energy standards are met, or whether it is their obligation to maximize the amount of energy they obtain up to the cap.

Issues such as these that are unanswered by the proposed rules could be sorted out in the process of approving the utilities' compliance plans instead of after the fact.

Lastly, the utilities suggested that a practical reason for the Commission to approve the utilities' compliance plans is to achieve the desired result of the legislation: for utilities to obtain the appropriate mix of renewable generation at an appropriate price. To discover after the fact that a utility should either have bought renewable power from another generator or that it paid too much for renewable power it did buy benefits no one – not the utility, not customers, not the renewable generator. A finding after the fact that a utility was imprudent does nothing to advance the goal of Senate Bill 3 to encourage renewable generation.

In its reply comments, NCSEA supported Duke's and Progress's concept of rigorous scrutiny of the compliance plan. NCSEA argued that the compliance plan should require public hearings and Commission approval.

The Hydro Group opposed changes that would make the compliance plans informational only, stating that the open planning process is one of the most important aspects of an effective REPS and that the information it provides is critical to the market. In preparing a renewable energy plan the electric power suppliers should evaluate the renewable energy market and determine the availability of renewable energy resources. Upon filing of the compliance plans the Commission will be able to review the electric power suppliers' choices and price points for REPS Credits and RECs they plan to purchase. Renewable energy developers and operators can clearly identify the current market for renewable energy, see the financial incentives which are available and make plans to meet the future requirements of the electric power suppliers.

The electric public utilities, which are the primary proponents of Commission approval of the REPS compliance plans, have often analogized the plans to the IRP plans filed by the utilities. The Commission agrees that REPS compliance is an integral part of the companies' overall supply-side and demand-side resource planning. Thus, it is natural that information regarding REPS compliance would be included in the companies' IRPs.

Recognizing, then, that the REPS compliance plans are comparable to IRP plans and that both involve an analysis of the supply-side and demand-side resources available to reliably serve load at least cost, the Commission concludes that Rules R8-60 and R8-67 should be revised to require each electric power supplier to file its REPS compliance plan as part of its IRP filing or, for any supplier not subject to G.S. 62-110.1 and the Commission's IRP rules, at the same time as the IRP filings – on or before September 1 of each year. This procedure will allow the electric public utilities' REPS compliance plans to be approved as part of the process of approving their IRP plans under Commission Rule R8-60. In that context, as suggested by the Public Staff, approval of the REPS compliance plan as part of the IRP will 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. 62-133.7(b), (c), (d), (e), and (f). The

REPS compliance plans filed by municipals or other electric power suppliers not subject to G.S. 62-110.1 and the Commission's IRP rules will not be approved by the Commission, but filed for information only.

The REPS compliance reports, by which the Commission will determine actual compliance with the REPS requirement, will be filed on a staggered basis and reviewed and approved for all electric power suppliers so that the Commission can comply with its obligation under G.S. 62-133.7(i)(1) to monitor "compliance with and enforcement of" the REPS requirement.

ISSUE 34. Years included in compliance plan

Proposed Rule R8-67(b)(1) requires each electric power supplier to include in its REPS compliance plan "information regarding the electric power supplier's plan for meeting the [REPS] requirements … during the two-year period including the current and immediately subsequent calendar years."

Progress proposed changes to the filing requirements for the REPS compliance plan to provide information for three years rather than two.

The Public Staff's proposed revisions to Rule R8-67(b)(1) also allow electric service providers, at their option, to include information about their REPS compliance activities for a period extending beyond two years. The Public Staff proposed to amend Rule R8-67(b)(1)(i) to provide that "[t]he plan shall cover the current and immediately subsequent calendar years, but may also include information relating to later years."

The Commission agrees with Progress and the Public Staff that additional information should be provided in the REPS compliance plans. The Commission therefore, concludes that subsection (b)(1) should be amended to require the REPS compliance plan to include information for a period of at least three years.

ISSUE 35. List of approved energy efficiency programs or measures to be included in compliance plans

Because energy efficiency measures are available for use in REPS compliance, the Public Staff proposed to amend Rule R8-67(b)(1)(i) to require electric power suppliers to include in their annual compliance plans "[a] list of approved energy efficiency programs or measures, including a brief description of the measure and projected impacts."

ElectriCities and NCEMC opposed the Public Staff's proposal. Since the recovery of costs associated with energy efficiency programs by municipalities is not subject to Commission review and approval and is not dependent upon the approval of an annual rider by the Commission, municipalities will not have "approved" programs or measures to list.

Although the filing of an REPS compliance plan is unrelated to cost recovery, the Commission finds good cause to change “approved” to “planned or implemented” and to add a separate provision for the reporting of DSM programs by cooperatives and municipals.

ISSUE 36. Approval of power purchase agreements

Proposed Rule R8-67(b) requires all electric power suppliers to file with the Commission an annual REPS compliance plan. Subsection (b)(1)(ii) required the electric power suppliers to provide “a list of executed contracts for the purchase of electric power or associated renewable energy certificates derived from renewable energy resources, including type, expected kWh and contract duration.”

Duke, Progress and Dominion proposed that language be added to the rule to allow suppliers the opportunity to apply for Commission review and approval of power purchase agreements before they are executed or become effective. Duke argued that such approval is necessary because electric suppliers will have to enter into long term power purchase agreements to secure the REPS Credits necessary to satisfy the requirements of Section 62-133.7(b),(c), (d) and (f). In addition, approval will assist renewable generators in obtaining financing for their projects. Lastly, approval will avoid utilities being placed in the position of being denied cost recovery for compliance with a State mandate despite reasonable and prudent efforts to comply.

SunEdison, Solar Alliance and NCSEA supported Commission approval of renewable energy contracts before execution. NCSEA noted that one of the elements of a compliance plan must be pre-approved contracts with clear costs. NCSEA suggested, however, that, to reduce the administrative workload, a contract threshold – in terms of capacity and/or cost – should be established that would then require Commission approval.

The Attorney General argued that, while renewable power purchase agreements will not be uniform, it is likely that many terms and conditions will be standard, particularly for smaller contracts. He suggested that the Commission direct the utilities to provide form contracts and terms that contain common provisions for review and approval within a reasonable time after the rules are adopted. This would provide transparency and certainty about expectations on both sides as the parties respond to the REPS requirement.

The Public Staff did not comment on this issue and did not include the language proposed by the utilities in its proposed rules.

Historically, the Commission has not interfered with the management of public utilities by approving individual contracts, except in the case of affiliate contracts where approval is specifically required by G.S. 62-153. While the Commission approves standard contract terms and provisions, including rates, for qualifying facilities in the biennial avoided cost proceedings, specific contracts may be negotiated between the utility and the energy supplier, and the resulting contracts are not approved by the

Commission. Lastly, in any case in which a contract has been approved, the Commission's order has generally specified that approval does not preclude subsequent challenge in a ratemaking proceeding.

The Commission concludes that it should not begin approving power purchase agreements now simply because they are being entered into at rates above avoided costs for the purpose of compliance with Senate Bill 3. The Commission has already indicated that it will review and approve the utilities' compliance plans. To make a determination as to whether to approve or disapprove specific contracts would require a more detailed review of proposed contracts. The obligation to comply with Senate Bill 3 lies with utility management, as a general proposition. The Commission's role is to approve integrated resource plans, to adjudge compliance with REPS and to allow recovery of reasonable and prudently incurred costs pursuant to Senate Bill 3 through annual riders. A decision to approve specific contracts in addition to the utilities' compliance plans would place the Commission in the position of making managerial decisions. The Commission, therefore, concludes that Rule R8-67 should not be revised to require approval of individual power purchase agreements with renewable energy suppliers as requested by the electric public utilities.

ISSUE 37. Compliance report

Proposed Rule R8-67(b)(2) requires each electric power supplier to file an REPS compliance report to be used to determine REPS compliance.

The Public Staff proposed a number of revisions to Rule R8-67(b)(2) relating to the electric power suppliers' annual compliance reports. First, the Public Staff proposed to delete subsection (b)(2)(i), which directs each electric power supplier to include in its annual compliance report "a comparison with the previous year's REPS compliance plan." In the Public Staff's view, the important question in a compliance report proceeding is whether the supplier has met the requirements of the REPS, not whether it has adhered to its compliance plan from the preceding year, particularly if that plan is not subject to Commission approval. Moreover, differences between the report and the previous year's plan will be apparent on their face. In addition, the Public Staff proposed to add the following items to the list of information required by Rule R8-67(b)(2) to be provided in the annual compliance report:

> (viii) The name and address of each renewable energy facility or energy efficiency supplier that has provided the electric power supplier with renewable energy or energy efficiency for which REPS Credits are claimed.
>
> (ix) The amount of renewable generation or energy efficiency provided by each renewable energy facility or energy efficiency supplier for which REPS Credits are claimed and the amount paid to the renewable energy facility or energy efficiency supplier.
>
> (x) An affidavit from the owner of each renewable generation facility that has provided the electric power supplier with renewable energy for

> which REPS Credits are claimed, certifying that the energy delivered was renewable, identifying the renewable technology used, and listing the dates and amounts of all payments received from the electric power supplier and all meter readings.
>
> (xi) An affidavit from each energy efficiency supplier that has provided the electric power supplier with energy efficiency for which REPS Credits are claimed, describing the nature of the energy efficiency provided, listing the dates and amounts of all payments received from the electric power supplier, and specifying all measurements or calculations provided to the electric power supplier quantifying the amount of energy consumption reduced, with a description of the dates of the measurements or calculations and a table of all results.

The Commission agrees, in part, with the unopposed proposal by the Public Staff. The Commission concludes that subsection (b)(2)(i) should be deleted. As discussed previously regarding the definition of an REC, however, neither G.S. 62-133.7(b)(2) nor (c)(2) provides for the supply of EE RECs to an electric power supplier for REPS compliance. The Commission, therefore, concludes that the information requested in proposed subsections (b)(2)(viii), (ix) and (x) should be added as proposed by the Public Staff without the references to "REPS Credits" or "energy efficiency supplier" and that subsection (xi), which is only applicable to the sale of EE RECs, is unnecessary.

ISSUE 38. Mandatory purchase of RECs

As proposed, Rule R8-67 does not specifically require electric power suppliers to purchase RECs to reach their REPS requirement. The clear implication of this rule and Senate Bill 3, however, is that the electric power suppliers are expected to take all actions necessary to satisfy the REPS requirement unless such actions would cost more than the annual cost caps.

Small Hydro argued that electric power suppliers should plan to buy "all financially and operationally viable REPS credits and RECs that are readily available to them." This mandatory purchase of RECs will stimulate the market and provide the market experience. Similarly, the compliance plan and compliance report should detail information regarding REPS credits and RECs offered to a supplier but rejected for inclusion in the plan.

The Commission expects electric power suppliers to purchase RECs as necessary, reasonable and prudent as part of a strategy to meet the REPS statutory mandate. The REPS compliance report and related proceedings will allow parties and the Commission the opportunity to address whether utilities did so appropriately. However, unlike the PURPA obligation to purchase power produced by QFs, the electric power suppliers are not, as urged by Small Hydro, obligated to purchase all RECs offered for purchase. The Commission is not persuaded that it is appropriate to impose such an obligation. The Commission, therefore, concludes that the rules need not spell out specific circumstances under which purchases of available RECs are or are not appropriate.

ISSUE 39. EE compliance based on projections

Proposed Rule R8-67(b)(2)(ii) requires an electric power supplier to include in its REPS compliance report "sources, amounts, and costs of REPS Credits claimed, by type: e.g., self-generation, co-firing, purchased electric power, in-state and out-of-state renewable energy certificates, energy efficiency."

Duke argued that an electric power supplier must be permitted to rely on estimates in determining the credits claimed for EE. Duke notes that the determination of actual EE results achieved as demonstrated through measurement and verification processes will likely take more than a year for new EE programs. Therefore, the rule should recognize that the REPS compliance report will reflect an estimate of the reduced energy consumption achieved through the implementation of EE measures. As EE results are verified, actual results can be incorporated into subsequent reports.

NCSEA contended that REPS Credits should be allowed only for measurable reduced energy consumption.

The Public Staff agreed with Duke. It will take a long time to arrive at reliable methods of measuring reduced consumption attributable to particular EE measures, and in some cases the only method of measurement may be through carefully reviewed estimates. The Public Staff proposed to add the following sentence to Rule R8-67(b)(2):

> REPS Credits 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.

The Commission finds good cause to adopt the change to Rule R8-67(b)(2) proposed by the Public Staff.

ISSUE 40. Hearing on compliance reports

The Public Staff proposed the following amendments to proposed Rule R8-67(b)(4):

> (4) The Commission may schedule a public hearing to receive public comments or expert testimony regarding any ~~REPS compliance plan or~~ REPS compliance report filed by an electric membership corporation or municipality. The Commission shall consider each electric public utility's REPS compliance report at the hearing provided for in subsection (c) of this rule and shall determine whether the electric public utility has complied with G.S. 62-133.7(b), (c), (d), (e), and (f).

The Commission finds good cause to adopt, in part, the Public Staff's proposal and clarify in Rule R8-67(b)(3) and (4) the procedures to be followed upon filing of REPS compliance plans and REPS compliance reports.

ISSUE 41. Filing dates for REPS compliance plans and REPS compliance reports by electric membership corporations and municipal electric suppliers

NCEMC proposed that Rule R8-67(b)(3) be amended so that electric membership corporations are required to file their REPS compliance plans and REPS compliance reports on or before September 1 of each year. NCEMC stated that this change is appropriate because its REPS compliance filing will be an integral part of its resource plan. As NCEMC's resource plan will be due no later than September 1 of each year, this would be the appropriate date to submit REPS compliance plans and reports.

The Public Staff supported NCEMC's proposal to change the filing date for the cooperatives and municipal electric suppliers, who are not subject to Rule R8-55, from April 1 to September 1 of each year.

The Commission finds good cause to modify the date by which electric membership corporations and municipal electric suppliers must file REPS compliance plans and REPS compliance reports to September 1 as proposed by NCEMC.

ISSUE 42. Conformity of REPS riders with Rule R8-55 and fuel charge adjustment proceeding

As with Rule R8-55 and the fuel charge adjustment, the utilities proposed changes to the rider in Rule R8-67(c) with regard to (1) interest on under-collections, (2) procedural dates, and (3) the period during which the EMF rider may be updated.

The Commission finds good cause continue, to the extent practicable, to employ the same procedures with regard to the REPS riders as with the fuel charge adjustment riders. Therefore, for the same reasons stated with regard to the fuel charge adjustment riders, the Commission concludes that it is appropriate to (1) deny the utilities' proposal to recover interest on under-collections, (2) require utility and intervenor filings on the same schedule as required under Rule R8-55, and (3) allow the utilities to incorporate experienced over- or under-recoveries "up to thirty (30) days prior to the date of the hearing."

ISSUE 43. Requirement to maintain procurement records

The Attorney General proposed adding a provision to R8-67(b) stating: "Utilities shall maintain complete records concerning policies and practices followed to procure supply from renewable energy facilities and REPS credits." The Attorney General took the position that the Commission may find it necessary to audit utility actions such as requests for proposals that are taken formally and informally to solicit supply from renewable energy facilities and to procure REPS credits to ascertain that the process is conducted fairly, reasonably and prudently.

NCSEA noted that Rule R8-67(b)(1) requires an electric power supplier to include in its REPS compliance plan an estimate of retail sales and executed contracts for renewable energy to meet the REPS requirement. From its discussions of best practices in regulated states, NCSEA took the position that the rules should require an additional oversight of the solicitation process and of renewable energy procurement contracts. To comport with this advice, NCSEA argued that a process must be established for the Commission to review the public utilities' solicitations of renewable energy projects before compliance plan submission to establish that the solicitations are well designed and the process is conducted fairly.

The Public Staff did not address this issue in its comments, but did not include the Attorney General's proposed language in its revised rules.

The Commission finds good cause not to include in Rule R8-67 the provision proposed by the Attorney General. The Commission fully expects the utilities to retain all necessary information to justify compliance with REPS and cost recovery. In addition, the Commission declines to require the additional oversight of the solicitation and procurement process, since issues of the type that NCSEA describes can be addressed in reviewing the electric power suppliers' compliance plans.

ISSUE 44. Deemed compliant

Duke proposed that the following language be added to Rule R8-67:

> An electric power supplier shall be conclusively deemed to be in compliance with the requirements of GS 62-133.7 if such utility has taken reasonable and prudent steps to implement the Commission approved compliance plan.

Duke argued that, in determining whether it has complied with the REPS requirement, it should not bear the risk that renewable energy resources fail to actually supply expected generation. Duke argued that this generation is dependent upon critical factors over which the electric utility has no control, including the performance of third party suppliers and, for numerous forms of renewable energy, the amount of rain, sun, or wind in a given year.

SunEdison, Solar Alliance, NCSEA and the Public Staff all opposed Duke's proposal. The Public Staff argued that the General Assembly intended that G.S. 62-133.7 be as fully binding on the State's utilities as any of their other statutory obligations.

The Commission concludes that it Rule R8-67 should not be revised to include Duke's proposed language. Electric power suppliers are expected to use all of their professional resources and expertise to comply with Senate Bill 3 to the same extent that they do for other legal and regulatory requirements. Although unexpected delivery failures may be relevant to Commission review of the electric power suppliers' compliance reports, the Commission does not believe that a good faith effort to carry out a compliance plan, standing alone, should suffice to constitute REPS compliance.

ISSUE 45. Timing and responsibility for retiring RECs

Proposed Rule R8-67(b)(5) addressing REPS compliance states:

> Renewable energy certificates (whether or not bundled with the purchase of electric power) claimed by an electric power supplier for compliance with the requirements of G.S. 62-133.7(b), (c), (d), (e) and (f) shall be retired and not used for any other purpose.

Small Hydro argued that an REPS credit or REC (regardless of whether it is bundled with energy or not) should be retired once an electric power supplier acquires it. At that point, the issuer of the credit or certificate would register that it had been retired, and it would no longer be tradable. This will help the market focus on growing renewable generation rather than on transactional versatility and speculation.

SunEdison and Solar Alliance proposed language stating that "RECs shall be used for a single purpose only, and shall be retired upon use for that purpose." All RECs used by the electric power supplier to comply with the REPS requirement and retired accordingly may not be sold in any jurisdiction or included within a blended energy product certified to include a fixed percentage of renewable energy in any other jurisdiction, but may be counted simultaneously toward compliance with any federal mandate similar to REPS.

ElectriCities and NCEMC stated that, once a market for RECs develops, RECs may be bought and sold by suppliers prior to their being claimed for REPS compliance. The electric power supplier that claims a REC for REPS compliance should be responsible for retiring the REC.

Progress, Duke and Dominion took the position that REPS credits and RECs should be retired upon use by the electric power supplier for compliance. Similarly, the Public Staff stated that RECs should be retired by the electric power supplier.

The Commission finds good cause to retain the language of Rule R8-67(b)(5) as originally proposed, but will add language to the rule clarifying that RECs must be retired at the time the utility uses them for compliance by filing its compliance report with the Commission.

ISSUE 46. Invocation of the off-ramp

Proposed Rule R8-67(b)(7) incorporates the language of G.S. 62-133.7(i)(2) authorizing the Commission to modify or delay the provisions of G.S. 62-133.7(b)-(f) if the Commission determines that it is in the public interest to do so. Concerns were expressed in the parties' comments regarding allowing other interested parties to petition for modification or delay of the REPS requirement, prohibiting retroactive application of any modification or delay decision, limiting the electric power suppliers to which any modification or delay applies, and establishing the showing required by an electric power supplier to qualify for relief under the rule.

First, the Public Staff proposed that the rule be worded to allow any interested party to propose modification or delay of the statutory provisions. In its view, G.S. 62-133.7(i)(2) was adopted to give the Commission power to respond to unexpected circumstances when no other, less sweeping remedy will meet the needs of the public interest.

Nucor agreed that all parties, not just electric power suppliers, should be allowed to petition the Commission to modify or delay the provisions of G.S. 62-133.7(b), (c), (d), (e) and (f). Under the Commission's proposed Rule R8-67(b)(7), only electric power suppliers may petition the Commission to modify or delay the REPS requirement. This limitation is not found in the statute. As the statute recognizes, electric power suppliers will be primarily responsible for complying with the REPS requirement, and any assessment of whether modifying or delaying the REPS requirement is in the public interest must take into account whether the electric power supplier has made a reasonable effort to meet the requirement. But this does not mean that only electric power suppliers should be permitted to petition the Commission to modify or delay the REPS requirement. All electric industry stakeholders – including utilities, power suppliers and customers – will be affected by the REPS requirement. The statute does not specifically limit the right to petition the Commission for a change in the REPS requirement to electric power suppliers, and, indeed, it would be a mistake to limit this right to one (albeit important) sector of the electric industry, given that an electric power supplier's view of what is in the public interest may not be shared by other sectors. Accordingly, all parties should have the right to petition the Commission to modify or delay the REPS requirement pursuant to G.S. 62-133.7(i)(2).

Second, the Public Staff stated that it did not believe the General Assembly intended to permit an electric supplier, when it finds itself out of compliance with the REPS requirement, to file a petition for a retroactive modification or delay of the requirement and thereby escape the imposition of sanctions. Accordingly, the Public Staff proposed to add a sentence to Rule R8-67(b)(7) prohibiting any retroactive modification or delay of the REPS requirement.

SunEdison and Solar Alliance agreed that the power to modify or delay the standard should not be permitted to be used retroactively as a means of evading compliance, stating that the Public Staff's proposed modification helps to provide the sort of certainty required to support significant investment in North Carolina.

Third, SunEdison and Solar Alliance contended that proposed R8-67(b)(7) should be revised to allow the Commission to modify or delay the REPS requirement of Senate Bill 3 with respect to only one electric power supplier or only certain designated suppliers as an alternative to modifying or delaying the REPS requirement for all suppliers.

The Public Staff agreed with SunEdison and Solar Alliance and stated that the proper course of action for the Commission to take when only one supplier or a limited number of suppliers has shown the need for a modification or delay of the REPS requirement, is to grant the modification or delay solely with respect to those suppliers who need it.

Lastly, SunEdison and Solar Alliance proposed additional language to specify the ways in which a utility must demonstrate that a modification or delay is appropriate. They would define "demonstration of reasonable effort" as competitive solicitations, the acquisition of RECs or bundled energy and RECs in advance of the effective date of the REPS requirement, and attempts to procure renewable energy or RECs from out-of-state facilities if adequate resources are not available in-state, and only to the extent permissible under Senate Bill 3. In addition, they argued that the Commission "shall consider the electric public utility's compliance in comparison to other suppliers having similar requirements."

Other parties also proposed modifications to clarify the demonstration that must be made to support modification or delay of the REPS requirement. In its initial comments, for example, NCSEA noted that the current wording of the rule provides no criteria or standards as to what constitutes a "reasonable effort." Reasons for noncompliance have to be based on causes that are demonstrably beyond the public utility's control. The expectation should be that the utility will prudently plan to deliver renewable electricity. Failure to do adequate planning should not be a cause for exempting the utility from compliance.

In its reply comments, the Public Staff stated that G.S. 62-133.7(i)(2) provides that when an electric power supplier petitions for a modification or delay of the REPS requirement, it must demonstrate that it has made a reasonable effort to comply with the existing requirement. SunEdison, NCSEA and CPV contend that the Commission should modify the proposed rule to specify criteria for determining whether the petitioner has made a reasonable effort to comply. The Public Staff agreed that the criteria suggested by SunEdison and NCSEA would be appropriate for the Commission to consider in deciding on a petition for modification or delay. However, the Public Staff stated that it is reluctant to specify criteria for use in determining whether a utility has made a "reasonable effort" in the Commission's rules for two reasons. First, every case is different, and specific cases may present unforeseen issues. Second, if the criteria are specified in the rule, this could be viewed as providing potential petitioners with a guideline to follow, which might encourage parties to file petitions for modification or delay when they might not otherwise do so. The Public Staff stated that it envisions this provision of this rule as a last resort; it should be available primarily to the smaller and less sophisticated electric power suppliers, and it should be used rarely, if at all, by utilities.

In their reply comments, Duke, Progress and Dominion stated that they support the Commission's proposed Rule R8-67(b)(7), which provides discretion for the Commission to grant a petition by a utility to modify or delay compliance with G.S. 62-133.7(b), (c), (d), (e) and (f) if the utility demonstrates that it made a reasonable effort to meet the requirements. Though not supporting the Public Staff's proposal to modify the rule to permit "other interested part[ies]" to petition for modification or delay, the utilities urged the Commission to provide safeguards to ensure that the utilities do not suffer "stranded costs" if the REPS compliance plans or the elements of the law are suspended or modified. If the Commission ultimately allows other interested parties to petition for a modification or delay to REPS compliance, the utilities recommended that the following sentence be added to the end of subsection (b)(7):

> If the Commission grants a modification or delay to G.S. 62-133.7(b), (c), (d), (e), and/or (f), each electric power supplier shall be allowed to recover its costs to implement G.S. 62-133.7(b), (c), (d), (e), and/or (f), including ongoing costs, where such costs cannot be mitigated, as though the modification or delay had not occurred.

The Commission finds good cause to adopt the changes proposed by the Public Staff and reject the change proposed by the utilities. The utilities will be provided ample opportunities to justify their recovery of REPS compliance costs and are entitled to recovery of costs reasonably and prudently incurred for the purpose of attempting to comply with the REPS requirement. The Commission, therefore, finds good cause to amend the rule as follows:

> In any year, an electric power supplier or other interested party may petition the Commission to modify or delay the provisions of G.S. 62-133.7(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. ~~The~~ 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. 62-133.7(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 suppliers for which a need for a modification or delay has been demonstrated.

ISSUE 47. Penalties

G.S. 62-133.7(i)(1) requires the Commission to adopt rules that "[p]rovide for the monitoring of compliance with and enforcement of the [REPS] requirements." In its October 26, 2007 Order, in response to comments urging the Commission to adopt penalties for noncompliance, the Commission stated:

> Although referencing enforcement, the statute does not provide any new penalty provisions or other enforcement mechanisms specific to the

> REPS. This reference to enforcement in S.L. 2007-397, therefore, must be to the Commission's existing authority under Chapter 62.

SunEdison and Solar Alliance agreed that the Commission's existing authority to impose fines and penalties under G.S. 62-310 is significant and should be sufficient to elicit compliance with the new REPS requirement if the Commission makes it explicit that such authority will be used to the maximum extent necessary, and that utility compliance with the REPS requirement stands on an equal footing with the other requirements imposed by law. Provided that the full non-recoverable penalties are assessed and compounded as authorized, they agreed that the accrual of penalties will be potentially more onerous than compliance with the thoroughly achievable standards of the REPS and, therefore, acts as a stimulus to utility compliance.

CPV urged the Commission to reconsider its rejection of any penalties for public utilities' failure to comply with the REPS, noting that the proposed rules contain more specific penalties applicable to providers of RECs for noncompliance with Rule 8-66 than to the public utilities for their failure to comply with the fundamental objectives of the statute. CPV recommended that the Commission impose an alternative compliance payment on a company that fails to meet its REPS requirement.

Wal-Mart agreed with other parties that the Commission's final rules should contain sufficient "teeth" to ensure compliance and noted that, while Senate Bill 3 allows utilities a certain amount of flexibility, this flexibility should not be used to avoid compliance. Wal-Mart did not propose any specific rule amendment relative to this issue.

NC WARN argued that enforcement measures are critical to the success of the REPS programs. A guide published by the National Association of Regulatory Utility Commissioners (NARUC) recommended enforcement measures, or at a minimum, strong incentives for the utilities to work closely with the renewable energy suppliers. Similarly, La Capra stated in its study for the Commission that "an effective RPS must be mandatory and impose some form of alternative compliance payments on load-serving entities that fail to comply." In reply comments, NC WARN proposed an enforcement rule:

> Upon its own merit or by motion of any party or through a complaint pursuant to Rule 1-9, the Commission shall initiate an investigation to determine whether a utility is meeting the requirements of its approved energy efficiency and DSM programs. After allowing the utility to respond to any allegations of deficiencies, the Commission may take enforcement action, including but not limited to financial penalties, if it determines that a program is being managed improperly.

In their reply comments, Duke, Progress and Dominion reiterated their assertion that the Commission should reject proposals to establish penalties for a utility's failure to meet the REPS requirement established by Senate Bill 3. The utilities agreed with the Commission's preliminary conclusion in its October 26, 2007 Order that Senate Bill 3 does not authorize new penalties or other enforcement mechanisms specific to the REPS established by the legislation and that none are needed. The continued advocacy by various environmental interveners and renewable energy suppliers for the implementation of such penalties should be rejected for a number of reasons. First, as has been previously explained, the idea of assessing penalties against utilities for failing to achieve the REPS requirement established by Senate Bill 3 was discussed and rejected during the legislative process resulting in the adoption of Senate Bill 3. The failure to include penalties was an express result of the legislative negotiations. All parties who supported Senate Bill 3 agreed to not include any penalties. Secondly, the electric utilities of this State are subject to comprehensive regulation by the Commission. As the Commission and the Public Staff have noted, the Commission has ample authority under existing law to ensure utility compliance with all state laws, rules and commission orders. Thirdly, the concerns that have prompted certain parties to propose the implementation of penalties support and demonstrate the reasonableness of the utilities' proposal that the Commission approve the utilities' REPS compliance plans, as well as the contracts they propose to execute, in order to meet their REPS obligations. By thoroughly reviewing and approving the utilities' compliance plans as well as the purchase power arrangements pursuant to which they intend to achieve compliance, the Commission and all interested parties can satisfy themselves that the utilities' plans are prudent, are being made in good faith, and are reasonably designed to achieve compliance. Finally, the payment of a penalty does nothing to support the production of renewable energy. In fact, the opposite may be true. If utilities are in danger of being assessed penalties for renewable energy suppliers' failure to deliver energy, the utilities will find it necessary to structure contracts that penalize those suppliers. Investors in renewable energy facilities will likely not look favorably upon such contractual conditions and may be reluctant to invest, thus resulting in projects that cannot be funded or investors looking for risk premiums that make the projects uneconomic. Imposing penalties on utilities could lead to less renewable energy being available for utilities to buy.

Similarly, ElectriCities and NCEMC took the position that the Commission's existing enforcement authority, including its general authority to impose fines and penalties under G.S. 62-310, is sufficient to elicit compliance.

The Public Staff stated that there have been suggestions by the utilities in their comments that the financial incentives of G.S. 62-133.7(h) will ordinarily provide them with sufficient motivation to meet the percentage requirements of subsections (b) through (f). If, however, in a particular year a utility finds that compliance with the applicable percentage requirements would be too costly, or would interfere with the utility's overriding obligation to provide an adequate supply of power to customers at the lowest cost, the utility should have the option not to meet the requirements. The Public Staff strongly disagreed with this position. Subdivisions (h)(3) and (4) of G.S. 62-133.7 protect the utilities from having to spend too much on renewable energy, and subdivision (i)(2) enables the Commission to modify or delay the percentage requirements when the public interest requires it. Unless the utilities request and obtain a modification or delay under subdivision (i)(2), the Public Staff believes that the percentage requirements of subsections (b) through (f) should be as fully binding as any other obligations imposed upon electric utilities under North Carolina law. In order to clarify that the requirements of G.S. 62-133.7 are not subordinate to but, on the contrary, are on an equal footing with all other duties imposed on electric utilities, the Public Staff recommended that the Commission state in its rulemaking order that, in complying with the REPS requirement, utilities are expected to use their engineering, financial, contingency planning and other capabilities to the same extent as they do in complying with other utility obligations.

The Public Staff noted that one way to ensure that the percentage requirements are met would be for the Commission to establish a specific monetary penalty for each megawatt-hour by which a utility falls short of any of the applicable percentage requirements in a given year. In their initial comments filed in late September in this docket, many environmental groups requested that the Commission establish such a penalty. However, Senate Bill 3 does not contain any penalty provisions, and if the Commission were to establish such a penalty now, it could be viewed as contrary to the compromises embodied in the REPS legislation. The Commission has tentatively concluded that its existing enforcement authority, including its authority to impose penalties, is sufficient to ensure compliance with the REPS requirement. To this end, the Public Staff stated that the Commission should maintain close oversight of REPS compliance and be prepared to impose the maximum penalty of $1,000 per day for each violation of the requirements of G.S. 62-133.7 and Rule R8-67. Neither of the two alternative versions of Proposed Rule R8-67(c), as they are currently worded, specifies whether a utility will be allowed to recover its renewable energy costs through the REPS rider if it fails to meet the REPS percentage requirement. The Public Staff stated that a utility should be allowed to recover such costs, if it can show that they were reasonable and incurred prudently and in good faith. Forfeiture of prudently incurred costs would not be a good sanction for violation of the REPS, because the closer the utility comes to meeting the requirements, the larger the forfeiture will be. The Public Staff proposed inserting the following sentence at the end of Rule R8-67(c)(16) to address this issue:

> An electric public utility shall be permitted to recover its costs incurred to comply with G.S. 62 133.7(b), (d), (e) and (f) even if the Commission finds that it has not met these requirements, to the extent that the costs were reasonable and were incurred prudently and in good faith for the purpose of complying with these requirements.

The Commission again finds good cause to reject proposals to define penalties for noncompliance. As the Public Staff stated, the electric power suppliers are expected to comply with this statute as they would any other. Similarly, the Commission finds that the Public Staff's proposed addition is unnecessary. Cost recovery will be determined in annual proceedings, with each electric public utility having the burden of proof with respect to its costs. However, as the Commission has previously stated, costs reasonably and prudently incurred in an effort to comply with the REPS requirement should generally be deemed recoverable in rates.

ISSUE 48. REPS rider to include a true-up

The REPS rider is authorized by G.S. 62-133.7(h)(4), which provides that an electric power supplier "shall be allowed to recover the incremental costs incurred to comply … and fund research …." The Commission's October 26, 2007 Order offered two alternatives for the REPS rider: Alternative 1 of proposed Rule R8-67(c) provided for a rider with a true-up; Alternative 2 provided for recovery of incremental costs actually incurred during a historical 12-month test period with no true-up. The Order requested comments on whether a true-up is permitted or appropriate.

Duke, Progress and Dominion strongly supported an REPS rider with a true-up. CUCA and NCFB also supported a rider with a true-up. The Public Staff, ED, SACE and SELC initially supported a historical rider with no true-up, but they changed positions in their reply comments to support a true-up rider. The Attorney General, CIGFUR, NCSEA, and Wal-Mart opposed an REPS true-up.

Those who opposed a true-up cited the language in G.S. 62-133.7(h) providing for recovery of "costs incurred," and they argued that this means costs which the utility has already become liable for, i.e., historical costs. They also cited State ex rel. Utilities Comm'n v. Thornburg, 84 N.C.App. 482, rev. denied, 320 N.C. 517 (1987), in which the Court of Appeals held that the fuel statute (before it was amended to include a true-up) did not authorize true-ups and that the Commission had exceeded its authority by implementing a true-up in a fuel charge adjustment case. The opponents read Thornburg as requiring specific statutory language before a true-up is permissible, and there is no such specific language in G.S. 62-133.7.

Those who supported a true-up argued that the opponents of such a mechanism are reading too much into the word "incurred" and that this word was not intended as a temporal limitation. They argued that the Commission has broad authority to establish provisional rates with true-ups, even without any specific enabling language, and they cited examples such as the Nantahala PPA, the Piedmont CUT, the gas utilities' curtailment tracking rates, Duke's DSM deferred account, and the refunds associated with the Tax Reform Act of 1986. They also cited G.S. 62-133.7(h)(5), which provides for adoption of rules "to allow for timely recovery" of all reasonable and prudent REPS costs, and argued that prospective recovery with a true-up avoids delay and is "timely." Finally, they argued that prospective cost recovery with a true-up will encourage the utilities to comply with the REPS mandate more enthusiastically and will further the goals of Senate Bill 3 more effectively.

In general, the Commission has approved a provisional or formula rate with a true-up when authorized by statute or in situations involving significant cost items that are uncertain and subject to rapid fluctuation beyond the utility's control. There is broad, though not universal, support for an REPS true-up among the parties. The Commission believes that the costs that will be subject to the proposed REPS rider are uncertain in amount, difficult to predict, and may be subject to fluctuations. Such costs are therefore appropriate for a provisional or formula rate. In addition, approval of a rider with a true-up will provide for "timely" recovery of costs, as authorized by G.S. 62-133.7(h)(5). Thus, the

Commission concludes that approval of an REPS rider with a true-up is appropriate as a legally-permissible formula rate of the type allowed pursuant to the Commission's authority under the general ratemaking provisions of Chapter 62 and under G.S. 62-133.7(h)(5).

The Commission will adopt an REPS rider with a true-up based upon Alternative 1 of proposed Rule R8-67(c) from the Commission's October 26, 2007 Order. The Public Staff proposed minor edits to Alternative 1, but the Commission does not believe that they are substantive and has not adopted these changes. Progress proposed that Alternative 1 be reworded to allow for an REPS rider based upon "projected costs." The Commission has retained the original wording on this point, but does not intend thereby to restrict either the evidence that it will consider or its flexibility to fashion a prospective rider as appropriate. At the annual hearings to determine the REPS rider, the Commission will receive and consider all relevant evidence that will help to determine an appropriate rider amount, including evidence of projected costs.

ISSUE 49. Cost allocation

In its initial comments, Progress presented three alternative proposals for language to be included in the cost recovery provisions, i.e., subsection (c) of proposed Rule R8-67. In two of the three alternative proposals, Progress included provisions that would require that the costs to be recovered through the REPS rider be allocated among customer classes based upon the single coincident peak methodology.

In its reply comments, CIGFUR supported Progress's proposed allocation methodology, stating that such an approach was reasonable and consistent with the provisions of G.S. 62-133.2(a2)(2).

In its reply comments, CUCA noted that it believed that the clarification offered by Progress with regard to the explicit adoption of a single coincident peak demand allocation methodology in Rule R8-67(c) was necessary and appropriate, but only to the extent that the Commission determines that no feasible means exist to charge actual costs to specific classes of customers.

In their reply comments, ED, SACE and SELC stated that they believed that the Commission should determine appropriate cost allocation methods in connection with its consideration of utility filings for rate riders and that a substantive rule governing the allocation methodology would be premature.

Nucor, in its reply comments, agreed that the single coincident peak methodology is an appropriate methodology for allocating REPS costs among customer classes. However, Nucor proposed that Progress's language be modified to state that costs will be allocated based on firm peak demand. According to Nucor, very often, interruptible (i.e., non-firm) load is not on the system at times of peak demand. Nucor further commented that, in fact, the value of interruptible load is that it can be curtailed at times of peak demand and that it was an important form of demand response, which was encouraged by Senate Bill 3. Finally, Nucor noted that not taking interruptible load into account when allocating REPS costs would be a reasonable and effective way to encourage interruptible load.

The Public Staff, in its reply comments, responded that "complex issues such as cost allocation are most appropriately addressed in a general rate case proceeding, not in a rulemaking proceeding." Moreover, the Public Staff stated that Progress currently uses the summer-winter peak and average allocation methodology.

Generally speaking, with respect to electric public utilities, cost allocations are typically used, among other things, to apportion joint and/or common costs among (a) a utility's regulated and non-regulated operations; (b) its various regulatory jurisdictions; and (c) its various jurisdictional customer classes, including sub-groupings, i.e., among the utility's various rate schedules within each customer class. They may also be used in apportioning costs among members of a controlled group of companies operating under the control of a common parent.

With respect to a utility's regulated operations, cost allocations are integral to the development and establishment of just and reasonable rates. In particular, they are widely used in the performance of cost of service studies.

The primary objective of a cost of service study is to identify the cost of providing service to each customer class, as well as to individual rate schedules within each class, based on load and service characteristics. Stated alternatively, the basic goal of a cost of service study is to identify the cost of providing service to the various classes of cost causers, i.e., to the various categories of customers receiving such service. The identification of costs in this manner invariably involves a myriad of cost allocations. Both the single coincident peak allocation methodology and the summer-winter peak and average allocation methodology have been used by the Commission in determining the cost of providing service by customer class, and by rate schedule within each customer class, in various proceedings in the past. However, in general, there is no one universally accepted methodology upon which all reasonably informed persons can agree to be the most appropriate approach for use in each and every instance.

In fact, cost allocation, for purposes of public utility ratemaking, is an exceedingly complex issue. It also has very significant consequences, as the methodology adopted for use by the Commission directly impacts the level of rates to be charged by the utility for the provision of service to customers within each customer class, including the allocation methodology's effect on the overall level of costs to be recovered from all customers on a jurisdictional basis. Given the high level of complexity and the gravity of the Commission's ultimate decision, the Commission is of the opinion that issues involving cost allocation, including the issue at hand, are most appropriately addressed and resolved on a case-by-case basis in the context of full evidentiary proceedings. Indeed, without the benefit of the evidence obtained in such proceedings, it would be extremely difficult, if not virtually impossible, for the Commission to appropriately resolve controversies of this nature. Simply stated, the Commission is of the opinion that the record in this rulemaking proceeding does not contain the information and data needed by the Commission to allow it to reach a fully informed, well reasoned decision with respect to the present issue.

The Commission, therefore, concludes that it should not include a requirement in the provisions of this Rule that would mandate the use of any particular cost allocation methodology.

ISSUE 50. Exclusion of certain costs from quarterly ES-1 Reports and annual cost of service filings

Rule R8-67(c) discusses cost recovery through an annual rider of the reasonable incremental costs prudently incurred to comply with the requirements of G.S. 62-133.7(b), (d), (e) and (f).

In its initial comments, Progress submitted that the impacts of the REPS rider and the REPS EMF rider should not be included in Earnings Surveillance Reporting (ES-1 Reports) and Annual Cost of Service Filings since such reports are designed to report on base rates.

In its reply comments, the Public Staff disagreed with Progress's proposal, stating that, for reporting purposes, the ES-1 Reports and the Annual Cost of Service Filings should reflect actual per book amounts that correspond to the utilities' financial statements and FERC Form 1 reports for ease of review and appropriate accounting of earnings per customer class as well as earnings for particular jurisdictions. According to the Public Staff, if the REPS costs as well as the REPS-related revenues were excluded from such reports, said filings would not provide all the cost of service information needed to review allocation factors, all costs per customer class, revenues per customer class and rates per customer class. Further, the Public Staff pointed out that the Commission has already stated in Docket No. E-2, Sub 837, regarding changes to the allocation of costs for services provided by Progress Energy Service Company, that actual operating experience is appropriate for ES-1 reporting. Finally, the Public Staff suggested that a utility could provide footnotes in its ES-1 Reports and Annual Cost of Service Filings which show the removal of the impacts of the REPS rider and the REPS EMF rider rather than completely excluding such information from the reports. The Public Staff noted that Duke currently provides such a footnote in its ES-1 Report describing the impact of weather normalization on its reported earnings.

In its reply comments, CIGFUR contended that Progress did not provide sufficient explanation or justification for its proposal to exclude the impact of the REPS from its ES-1 Reports or Annual Cost of Service Filings; consequently, such treatment did not appear warranted.

The Commission agrees with the Public Staff and concludes that Rule R8-67(c)(4) and (6) should not include the additional language requested by Progress.

ISSUE 51. Recovering the costs of RECs in the REPS rider

Proposed Rule R8-67(c)(1) speaks to this issue indirectly by establishing a process for reviewing REPS compliance costs prior to their recovery via an annual rider.

NCSEA stated that G.S. 62-133.7(h) allows electric power suppliers to recover the incremental costs incurred to purchase RECs to comply with the REPS requirement. Electric public utilities should be able to recover costs incurred to purchase RECs that have been retired toward compliance. Purchased RECs that are not retired for compliance in a designated year, or which have expired or have been sold as excess, should not be eligible for cost recovery.

The Public Staff asserted that the entire cost of the REC should be treated as incremental cost and recovered through the REPS rider. The Public Staff proposed language to make this clear: “The cost of a renewable energy certificate, to the extent that it is reasonable and prudently incurred, is an incremental cost and has no avoided cost component.”

The Commission finds good cause to include in Rule R8-67(c)(2) the Public Staff’s proposed language, which the Public Staff proposed for inclusion in the definition of “incremental costs.”

ISSUE 52. Timing of cost recovery

Proposed R8-67(c)(10) states:

> The costs associated with the electric power supplied by a new renewable energy facility that are carried over to a future period may be recovered in the year such costs are incurred if the electric public utility’s total annual incremental costs incurred in that year do not exceed the per-account annual charges provided in G.S. 62-133.7(h)(4). Such costs not recovered in the year incurred may be recovered in any subsequent year up to the year of retirement of the associated renewable energy certificates as long as total costs charged in such future year are below the annual cap for that year.

CIGFUR argued that the statute does not provide for the carry-over of costs. Similarly, CUCA argued that carrying over excessive charges from year to year is plainly inconsistent with the spirit and intent of the annual caps imposed by Senate Bill 3 and creates inter-generational inequities.

Progress, Duke and Dominion asserted that Rule R8-67 should make explicit that REPS credits and associated RECs do not expire, that they may be carried forward for use in compliance in future years, and that costs may similarly be carried forward for recovery in future years. They argued that the utility has no control over the amount of energy it will receive on its system from renewable resources under contract because solar and wind are not dispatchable. In its initial comments, Progress proposed that

Rule R8-67 be amended to clarify that the cost associated with REPS credits that are carried over to a future period may be recovered in the test year in which the costs are incurred if the cost caps are not exceeded.

The Public Staff argued that electric power suppliers should be allowed to bank REPS credits to a certain extent, but not indefinitely. Some carry-over of incremental costs from one year to the next should be allowed, but it should be limited. The normal practice should be for incremental costs to be included in the REPS rider test period for the same year the associated REPS credits are used for compliance. Utilities might need to purchase renewable energy so far in advance of 2012, however, that they have no opportunity to use the REPS credits for compliance in earlier years. In that event, they should be permitted to include the incremental costs, less the revenues received from the sale of the RECs associated with the REPS credits, in the rider test period in the same year they are incurred. The Public Staff proposed these amendments:

> In the event an electric public utility incurs reasonable and prudent incremental costs for REPS Credits to comply with G.S. 62-133.7(b), (d), (e), and (f) in a calendar year, and those costs (together with other incremental costs for such year) exceed the revenues the electric public utility is permitted to recover from its customers pursuant to G.S. 62-133.7(h)(4) in such calendar year, the electric utility shall be permitted to carry those costs over. The costs associated with the electric power supplied by a new renewable energy facility that are carried over to a future year may be recovered through the rider proceeding in such future year if the electric public utility's total annual incremental costs incurred in that year do not exceed the per-account annual charges provided in G.S. 62-133.7(h)(4). Such costs not recovered in the year incurred may be recovered in either of the next two years as long as total costs charged in that year are below the annual cap for that year, but shall not be recovered in any subsequent year.

G.S. 62-133.7(h)(5) states that:

> The Commission shall adopt rules to establish a procedure for the annual assessment of the per-account charges set out in this subsection to an electric public utility's customers to allow for timely recovery of all reasonable and prudent costs of compliance with the requirements of subsections (b), (c), (d), (e), and (f) of this section and to fund research as provided in subdivision (1) of this subsection.

G.S. 62-133.7(h)(4) allows an electric power supplier to recover incremental costs beginning in 2008. The intent of Rule R8-67(b)(10) was to allow an electric public utility to recover, subject to true-up, the costs associated with REPS compliance during the year in which the cost was expected to be incurred or in any subsequent year up until the time the REC was claimed for REPS compliance, subject to the cost cap in G.S. 62-133.7(h)(4). For example, if an electric public utility purchases renewable energy and associated RECs in 2008 for compliance in 2012, the utility may seek to recover the incremental cost associated with that energy in any year between 2008 and 2012. If, however, the incremental cost associated with that energy would cause the utility to exceed the cost cap in any year and the REC was not necessary for REPS compliance in that year, both the REC and the incremental cost could be “carried over” to the next year. Costs may not be carried over beyond the year for which the associated REC is claimed for REPS compliance. Incremental costs that exceed the cost cap in the year in which the associated REC is claimed for REPS compliance may not be recovered.

Senate Bill 3 establishes new, multi-faceted obligations. Electric power suppliers must secure an ever-increasing amount of their customers’ electricity via renewable energy and efficiency, with set-asides for solar, poultry and swine resources. They are to accomplish this result via a rigid schedule of time lines and price caps. The Commission concludes that, to assure success, electric power suppliers must have some flexibility in timing the acquisition, use for compliance (retirement) and cost recovery for these resources.

With regard to cost recovery for an electric public utility, therefore, the Commission concludes that R8-67(c)(10) should be clarified such that, if the utility carries RECs forward into the next year, it has the option of recovering the costs in the year they were incurred or in the year the associated RECs are used for compliance, unless any such recovery would go beyond the cost caps established by Senate Bill 3. However, the Commission is concerned that a utility could recover the costs associated with a REC and “bank” it for compliance indefinitely, thereby creating an inter-generational mismatch between the customers who paid for the REC and the customers who benefit. Therefore, the Commission concludes that a specific REC should be used for compliance (retired) within seven years of the year in which its costs are recovered from customers. If the electric public utility does not retire a REC within seven years of cost recovery, it shall refund the associated costs to customers with accrued interest.

ISSUE 53. Requirement for long-term contracts

G.S. 62-133.7(d) provides:

> 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.

As proposed, R8-67(d)(1) states:

> 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.

The Public Staff proposed amendments that would require contracts between electric power suppliers and solar or solar thermal facilities to be at least 15 years long if desired by the renewable energy facility. Without this requirement, solar operators and electric power suppliers will litigate the issue of whether the contract term the supplier has offered is long enough. The Public Staff stated that the Commission held in its last avoided cost order, Docket No. E-100, Sub 100, that the State's electric utilities should offer contracts of up to 15 years to solar QFs, which many have found to be helpful in obtaining financing.

CPV argued that, while the statute only contains language relating to solar power facilities, the existence of the statute itself provides reasonable grounds for the Commission to place a similar requirement on contracts between an electric power supplier and any new renewable energy facility. Absent such a requirement, suppliers are free to offer contracts with terms that are patently too short to permit the financing of renewable energy facilities in a cost-effective manner. Such behavior could discourage the development of renewable energy facilities, and lead to a failure of the program. At a minimum, wind projects with a ten year tax credit and corresponding tax investment need contracts of at least ten years to provide the certainty needed by investors.

Similarly, NCSEA urged the Commission to encourage regulated utilities to enter into long-term RECs contracts for all renewable energy resources or, at a minimum, those established through a set-aside. NCSEA supported CPV's recommendation that contract terms with any new renewable energy facility should be of sufficient length to stimulate development of renewable energy. A long-term contract often enables a renewable energy generator to deliver RECs and electricity to a regulated utility for REPS compliance at a lower cost than a short-term contract. This happens because non-capital project costs are significantly affected by the terms of the REC purchase contract. As a result, long-term RECs contracts between regulated utilities and renewable energy generators can have a dampening effect on the aggregate compliance cost of a state renewable energy mandate while still delivering the same amount of reliable, renewable electricity to the grid. Several states have acknowledged the significant cost savings to ratepayers of explicitly requiring long-term contracts in law or in rules. For example, Maryland and Delaware both require 15-year contracts for the purchase of solar RECs, and Colorado requires a 20-year contract term. NCSEA recommended that the Commission modify proposed Rule R8-67(d)(1) to establish a 15-year or greater contract duration requirement.

In their reply comments, ED, SACE and SELC supported both the Public Staff's and NCSEA's proposals.

SunEdison and Solar Alliance also recommended 15-year contracts for solar facilities, citing similar requirements in Maryland. Contracts of this length are adequate to capture the majority of the RECs value stream and reduce the risk premium paid by ratepayers for shorter contracts.

Small Hydro noted that many hydro operators have existing contracts for the sale of electric power to the interconnected electric utility. The existing power purchase agreements between those hydro operators and the electric utilities relate only to the purchase of electric power, and do not include the RECs. To facilitate the initial REC transactions between existing renewable generators and electric power suppliers, Small Hydro stated that the electric power suppliers should offer contracts which match the terms of their existing energy contracts, i.e., the expiration date of the REC contracts would be co-extensive with the expiration date of the existing power purchase agreements. In addition, all renewable electric generators should have the choice of long-term contracts for REPS Credits and RECs in order to provide revenue certainty and fund the development of their facilities. Small Hydro proposed that electric power suppliers be required to offer REPS Credit and REC contract terms which match the contract terms offered to Qualifying Facilities and small power producers.

Duke, Progress and Dominion opposed mandatory contract duration terms. Mandated, long-term contracts for renewable energy generation could lead to imprudent financial terms and undermine long-term compliance with the requirements of Senate Bill 3. With unproven entrants and constantly evolving technology, long-term contracts subject utilities, ratepayers and the public to significant risk. Senate Bill 3 has already made the economic policy decision to create a market for renewable energy by setting compliance levels. The Commission should not go further than the General Assembly in creating demand for renewable resources.

ElectriCities and NCEMC also opposed the Public Staff's proposal, arguing that it would eliminate needed flexibility in contract negotiations and unnecessarily interfere with the contracting parties' ability to negotiate at arms length. They asserted that the market will dictate the appropriate terms and conditions.

The Commission finds good cause to reject proposals that would require electric power suppliers to enter into long-term contracts with any renewable energy facility or that would dictate specific contract duration provisions. Such a requirement would limit the electric power suppliers in their negotiations for renewable energy. However, a decision by an electric power supplier not to enter into long-term contracts will not be allowed as an excuse for failing to meet the REPS requirement if sufficient resources are otherwise available.

ISSUE 54. Relief from solar default

As a proviso to the requirement for contracts "of sufficient length" with solar facilities, G.S. 62-133.7(d) requires the Commission to

> develop a procedure to determine if an electric power supplier is in compliance [with the solar set-aside] if a new solar electric facility or a new metered solar thermal energy facility fails to meet the terms of its contract with the electric power supplier.

As proposed, the rules do not explicitly address this issue.

The Public Staff proposed the addition of the following as Rule R8-67(d)(3):

> The failure of a new solar electric facility or new metered solar thermal energy facility to meet the terms of its contract with an electric power supplier shall not relieve the electric power supplier of its obligations under G.S. 62-133.7(d), unless the electric power supplier petitions the Commission for, and is granted, full or partial relief from such obligation. Relief shall not be granted to an electric public utility except in extraordinary circumstances.

The Public Staff argued that a contractual default by a solar operator should not ordinarily relieve an electric power supplier from its obligations under the REPS. A utility should turn to a backup supplier or purchase power on the open market in the event of a default on the part of a supplier. If the utility cannot find a new supplier in time, it can purchase solar RECs on the market.

ElectriCities and NCEMC opposed the Public Staff's proposal, arguing that the solar resource market is new and emerging and may not be as reliable as the mature power supply market, with which electric power suppliers have extensive experience. The market for solar RECs has not yet developed and may never develop to the extent necessary to impose such a burden on electric power suppliers. Nothing in the rules should require electric power suppliers to engage in redundant solar purchases. An electric power supplier should only have to indicate in its annual compliance report if a default occurred and the resulting effect on its ability to satisfy the solar REPS requirement. So long as the electric power supplier includes reasonable and customary contract provisions to protect itself from default, it should not be penalized in the event default occurs.

The Commission finds good cause not to adopt the Public Staff's proposal. G.S. 62-133.7 only requires the Commission to develop a "procedure" for determining compliance. The procedure for determining compliance adopted in the rules is through the review of an electric power supplier's REPS compliance report. An electric power supplier may petition the Commission to modify or delay the provisions of G.S. 62-133.7(d) and Rule R8-67(c)(5). The Commission concludes that no further language is necessary in the rules to address this issue.

ISSUE 55. Aggregation or brokering of RECs

Small Hydro took the position that aggregation and brokering will make the North Carolina renewables market more efficient. Aggregators can serve a significant need for renewable generators by reducing the transaction cost of getting RECs to market . This is important for small generators, whose transaction costs are high relative to the value of the RECs the generator might have to offer. An aggregator should be allowed to buy RECs from generators for resale to electric power suppliers, and aggregators and brokers should be allowed to market RECs to electric power suppliers. Further, where an aggregator is qualified and registered with the Commission to do so, it should be allowed to issue, trade, track and retire REPS credits and RECs.

Nothing in the proposed rules is intended to prevent a generator from selling its RECs to an aggregator or broker. It is up to an electric power supplier to decide whether to purchase RECs from an aggregator or broker for REPS compliance.

The Commission concludes it is not necessary for the Commission to amend the proposed rules to encourage aggregation or brokering of RECs. The Commission finds that aggregators and brokers may serve a useful role in North Carolina. That role is not one of issuing or retiring RECs, but of facilitating the sale of RECs to electric power suppliers.

ISSUE 56. Existing power purchase agreements

In its reply comments, Small Hydro first asserted that existing power purchase agreements relate only to the purchase of electric power and do not include RECs. Electric power suppliers should offer REC contracts that match the terms of their existing energy contracts – i.e., the expiration date of the REC contracts would be coextensive with the expiration date of the existing power purchase agreements. Electric power suppliers should be required to offer REPS Credit and REC contract terms which match the contract terms offered to QFs and small power producers. Electric power suppliers should be required to offer renewable generators the option of selling a bundled energy and REPS credit contract, or an energy only contract and a separate REC contract.

SunEdison proposed that all power contracts entered into after the effective date of these rules should clearly specify the entity that owns the RECs associated with the energy generated by the facility.

In its recent avoided cost dockets, the Commission has found and concluded that a power purchase agreement does not transfer ownership of the environmental attributes associated with the purchased energy unless otherwise specifically stated in the contract. In its Order issued December 19, 2007, in Docket E-100, Sub 106, establishing standard rates and terms for avoided cost contracts with qualifying facilities, the Commission reaffirmed its decision in Docket E-100, Sub 100 that “the sale of power by QFs at avoided cost rates does not convey the renewable energy credits (RECs) or green tags associated with such generation.” The Commission concludes that there is no reason for the Commission to disrupt the equities in existing contracts by requiring renegotiation. However, if an electric power supplier needs the RECs associated with power that it is already purchasing, it can re-negotiate those contracts as necessary. Electric power suppliers are not obligated to purchase any and all RECs that are offered for sale. This would include RECs associated with power that is already the subject of a power purchase agreement. However, electric power suppliers are obligated to comply with Senate Bill 3, and the Commission expects them to enter into new or amended contracts as necessary in order to comply. The Commission concludes that, since it will focus on overall compliance with Senate Bill 3, it is not necessary for the Commission to prescribe the terms and timing of contracts electric power suppliers enter into with QFs and small power producers beyond what is already required by law and regulation.

ISSUE 57. Restrict fossil fuel use in renewable energy facilities

In his reply comments, the Attorney General recommended that the Commission clarify the extent to which fossil fuels can be used by renewable energy facilities. Neither Senate Bill 3 nor the proposed rules address this issue.

The Attorney General noted that the proposed rules do not define the various renewable energy resources. Since the use of fossil fuels in renewable energy facilities for start-up or stabilization purposes is not specifically authorized in the rules, the Attorney General argued that a renewable energy facility may not use them unless an exception is approved by the Commission. The Attorney General noted that the FERC rules for qualifying small power production facilities explicitly limit the use of fossil fuels to certain purposes and cap the allowed percentage of fossil fuel use. See 18 C.F.R. 292.204.

The Commission notes that the purpose of the REPS and the rules implementing Senate Bill 3 are fundamentally different from the FERC rules implementing PURPA. In establishing rules to implement PURPA, the FERC was required to set a limit on fossil fuel use for qualifying facilities (QF) whose primary energy source is a renewable resource. Under Senate Bill 3, a renewable energy facility is not required to qualify as a QF under PURPA. In other words, a facility's QF status is independent of its entitlement to RECs for the renewable energy it produces. However, RECs may be earned only for that portion of a facility's energy output that is derived from a renewable energy resource.

The Commission, therefore, finds good cause to add a provision to Rule R8-67 to clarify that RECs earned by a facility that uses both renewable and nonrenewable energy resources shall be determined by the percentage of the facility's output resulting from a renewable energy resource.

ISSUE 58. Metering of thermal energy

Proposed Rule R8-67(e)(4) addresses how to measure the waste heat that is recovered for useful thermal applications in combined heat and power (CHP) systems, and how to measure the thermal output of solar thermal facilities.

The Attorney General suggested two changes to the proposed rule. First, the rule should measure the thermal energy that is employed for useful purposes. The rule as currently proposed would measure the thermal energy from a CHP system or solar thermal facility by metering the thermal energy produced. Thus, as the rule now reads, a facility might be credited with all thermal energy produced, although not all thermal energy is recoverable and used for useful purposes. The second change suggested by the Attorney General concerns the requirement that the thermal energy be "metered." Metering what energy is used where in a facility (particularly measuring the lower grade thermal applications) may be difficult and overly costly. G.S. 62-133.7(a)(8) does not require that the thermal energy be metered. Instead, the measurable thermal output of the facility might be determined by assessing the amount of thermal energy that is recovered and used in the design and operation of the system or facility. Monitoring the correctness of that measurement may be challenging, but the use of such an approach would be more accurate than simply metering the total thermal energy available for thermal applications. To address these two points, the Attorney General suggested the inclusion of the following modified language in Rule R8-67(e)(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 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 kilowatt-hour for every 3,413 of British thermal units (Btus) of thermal energy produced.

The Public Staff supported the Attorney General's proposal. The Public Staff incorporated the changes into its proposed rule with minor modifications to which it stated the Attorney General had agreed.

The Commission finds good cause to adopt the Attorney General's proposal as modified by the Public Staff, with the exception that, as indicated by earlier commenters and available scientific literature, one kilowatt-hour is equal to approximately 3,412 Btus.

ISSUE 59. Metering of other renewable energy facilities

Proposed Rule R8-67(e)(1) requires that power generated by a renewable facility be measured by a meter supplied and read by an electric power supplier.

CIGFUR argued that this may not be the most practical approach in all situations, particularly when sales are to be made in more than one jurisdiction. CIGFUR recommended revising this subsection to require a meter mutually satisfactory to buyer and seller.

Wal-Mart argued that Rule R8-67(e)(3) would impose a 1 MW capacity limit on renewable energy facilities interconnected behind the utility meter at a customer's location. Facilities larger than 1 MW would not receive renewable energy certificates unless measured by an electric meter supplied by and read by the electric utility pursuant to subsection (e)(1). Wal-Mart argued that Senate Bill 3 imposes no such limitations, nor are they necessary. G.S. 62-133.7(i)(4) requires the Commission to adopt rules for interconnecting renewable energy facilities with a capacity of up to 10 MW. The 1 MW limitation of subparagraph (e)(3) appears to be arbitrary and unsupported by the language of SB 3. Furthermore, the requirement that renewable energy facilities larger than 1 MW must be measured by an electric meter supplied by and read by the electric utility does not appear to be supported by the language of SB 3. In addition, as proposed, subparagraph (e)(3) would require only ANSI-certified electric meters. Wal-Mart suggested that the rule be broadened to allow the use of non-ANSI-certified meters, provided that they meet the accuracy requirements of the

Commission's rules. Wal-Mart argued that the Commission's existing rules do not require ANSI-certified meters. Further, the proposed subsection (e)(3) requires the owner of customer-supplied meters to comply with the meter testing requirements of Rule R8-13. This requirement should provide adequate protection for utilities and other customers.

The Public Staff opposed CIGFUR's proposal to allow metering of renewable energy by any method agreeable to the buyer and seller. There is a need for a standard metering method to ensure that the Public Staff and Commission can adequately audit claimed REPS Credits and the associated costs in connection with an REPS compliance proceeding or rider proceeding.

The Public Staff also disagreed with Wal-Mart's proposal to amend Rule R8-67(e) to allow a renewable energy facility with a nameplate capacity of up to 10 MW to interconnect behind the utility meter, install its own meter and self-report the meter data. In addressing proposals for self-reporting, the Commission must balance the reduced administrative burden resulting from self-reporting against the risk of inaccurate self-reporting. It is up to the Commission to draw a line separating facilities that will be allowed to self-report from those that will not, and the Public Staff believes that the Commission has appropriately drawn the line at a 1 MW rather than a 10 MW nameplate capacity. The Public Staff also disagreed with Wal-Mart's proposal that renewable energy facilities interconnecting behind the utility meter be relieved of the obligation to use an ANSI-certified meter. The Public Staff and Commission should not have to bear the burden of familiarizing themselves with meters that are neither ANSI-certified nor purchased by a utility under Commission supervision, determining whether these non-certified meters are accurate, and addressing any problems that arise as a result of meter inaccuracy.

The Commission finds good cause not to adopt CIGFUR's and Wal-Mart's proposals to amend Rule R8-67(e). In drafting the proposed rules for comment, the Commission reviewed and incorporated best practices from other jurisdictions with respect to this issue and as suggested by several commenters. After reviewing the record, the Commission continues to believe that requiring metering of the type suggested in the proposed rule is appropriate.

RULES R6-95 & R8-68

ISSUE 60. Definition of least cost mix

ED, SACE and SELC first noted in their comments that the Commission's proposed rules do not adhere to G.S. 62-133.8(b), which states:

> Each electric power supplier shall implement demand-side management and energy efficiency measures to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of its customers.

They urged the Commission to define least cost mix as

> that combination of demand-side initiatives (DSM and EE) and generation resources which minimizes the present value of the revenue requirements of the electric power supplier plus the incremental costs incurred by customers to participate in DSM and EE initiatives.

This definition, they argued, corresponds to the total resource cost (TRC) test. In the alternative, they recommended that the Commission define least cost mix as that combination of DSM and generation resources that minimizes the present value of the revenue requirements of the electric power supplier. Since the cost and performance characteristics of DSM and generation resources fluctuate, ED, SACE and SELC also recommended a regular process whereby the electric power suppliers assess these options to define least cost mix. ED, SACE and SELC indicated that past IRPs failed to require the electric power suppliers to regularly identify the achievable cost-effective DSM and EE.

The Public Staff did not support the incorporation of either definition of least cost into the Commission's rules at this time. The proposed rules provide that the electric power suppliers will submit a great deal of information regarding their analysis of DSM and EE programs and measures for the Commission's consideration. In addition, the new IRP rules require the electric power suppliers to submit additional information regarding their analysis of DSM and EE programs as incorporated into their planning and forecasting processes. Both these proposed rules and the new IRP rule should leave the Commission and other interested parties better informed on how electric power suppliers analyze and evaluate DSM and EE measures and programs. Additional rules are not necessary at this time.

In their joint reply comments, Duke, Progress and Dominion also argued that this proposal is incorrect and should be rejected in light of the Commission's approval of revised IRP rules on July 11, 2007. These revised rules require:

> <u>Alternate Supply-Side Energy Resources</u>. As a 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.
>
> <u>Demand-Side Management</u>. As a 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.
>
> <u>Evaluation of Resource Options</u>. As a 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.

Further, Rules R8-60(i)(6) and (7) require extensive reporting on the results of the utility's assessment of demand side management and alternative supply-side energy resources. Duke, Progress and Dominion asserted that there is no basis for ED, SACE and SELC's recommendation, and it should be rejected.

The Commission agrees with the Public Staff and the utilities that additional rules on this issue are not necessary. The Commission expects the utilities' IRP filings, including REPS compliance plans pursuant to Rule R8-67(b), to fully consider DSM and EE options and to explain the reasons that a utility chose to either include or decline to include specific programs in its resource plan.

ISSUE 61. "Combined heat and power system" in the definition of "energy efficiency measure"

Proposed Rules R8-67(a)(4) and R8-68(b)(4) both define "energy efficiency measures." They include language that restricts the circumstances under which a combined heat and power (CHP) system using nonrenewable fuels can qualify as an EE measure.

The Public Staff proposed language to prevent the "gaming" of the REPS by CHP systems using nonrenewable fuels. Senate Bill 3 allows an electric utility to meet some of its REPS obligations with EE measures. CHP systems using nonrenewable fuels are included in the definition of "energy efficiency measures." The Public Staff contended that, without restrictive language, an electric power supplier could build a large cogeneration plant using nonrenewable fuels on an industrial customer's premises, use some of the steam produced at the plant to heat the industrial customer's facilities, and then use the power produced by the CHP system to meet the EE component of the electric utility's REPS requirement. The Public Staff supported language in proposed Rules R8-67(a) and R8-68(b) that purportedly closes off what it characterizes as this "gaming" opportunity by stating that, to qualify as an "energy efficiency measure," a CHP system that uses nonrenewable resources would have to produce electricity or useful, measurable thermal or mechanical energy for the retail customer's use that results in less energy being used at the retail customer's facility. In proposing changes to the rule, the Public Staff used language that differed from the language of G.S. 62-133.7(a)(1). A phrase in the statute that reads "at a retail electric customer's facility" was changed to "for the retail customer's use" in the Public Staff's proposed rule. The Public Staff also proposed to transfer the definition of "energy efficiency measure" from Rule R8-68(b)(4) to Rule R8-67(a)(4) and to cross-reference it in Rule R8-68(b)(4).

CHPA supported the Public Staff's proposal.

The Attorney General stated that if a utility seeks approval of an EE program pursuant to proposed Rule R8-68 involving a CHP system that uses fossil fuels, the Commission should determine what EE standard applies. The Attorney General also stated that the Commission may find it necessary to review the design of such facilities to determine what produces the "waste heat" that is used in the CHP system to produce electricity or useful measurable thermal or mechanical energy.

No other party opposed the Public Staff's proposed definition of a CHP system to qualify as an EE measure.

On a careful reading of the law, the Commission does not agree with the Public Staff that there is a danger of gaming resulting from reliance on CHP systems. G.S. 62-133.7(b)(2)c explicitly states that, to meet its REPS obligations, an electric public utility may "[r]educe energy consumption through the implementation of an energy efficiency measure." Therefore, as an EE measure for REPS compliance, the electric public utility must "reduce energy consumption." The use of some measure of waste heat recovery in a CHP system would not allow all of the <u>power</u> generated by that system to qualify for REPS compliance unless the power were generated through the use of a renewable energy resource. The only benefit that can be claimed in the EE part of REPS is energy actually saved.

While the Commission is not convinced that the Public Staff's CHP language is necessary, it concludes that the Public Staff's language should be adopted, with a modification. The phrase in proposed Rule R8-67(a)(4)(i) that states "for the retail customer's use" should be revised to conform to the statutory reference to "at a retail electric customer's facility." The Commission also agrees that the definition of "energy efficiency measure" should be defined in Rule R8-67(a) and referenced in R8-68(b).

With regard to the Attorney General's suggestions, the Commission concludes that it should not attempt to determine energy efficiency standards for CHP systems. As stated with regard to fossil fuel use for renewable energy facilities, energy efficiency standards are only applicable in determining whether a CHP system meets the requirements of a QF under PURPA. A CHP system's status as a QF is independent of its entitlement to RECs under Senate Bill 3. The Commission further concludes that, while examination of a CHP's design to determine what produces "waste heat" may be worthwhile, such inquiry should be pursued on a case-by-case basis when a facility registers under Rule R8-66.

ISSUE 62. Use of incentive programs for utility load-building

Proposed Rule R8-68(b)(4) defines "energy efficiency measure" as a change that results in less use of energy.

Several parties argued that the definition of "energy efficiency measure" should include the use of non-electric fuels such as natural gas and that EE measures should be evaluated on a total cycle basis. PSNC argued that Senate Bill 3 prohibits an EE measure which results in building electric demand. ED, SACE, SELC, Piedmont and PSNC requested that the definition of "energy efficiency measure" be revised to explicitly include measures that save electricity by installing technologies that use non-electric fuels to perform the same function more efficiently. They asked that this sentence be added to the definition in Rule R8-68(b)(4): "'Energy efficiency measure' includes technologies that use non-electric fuels in lieu of technologies that use electricity, to perform the same function."

Chapel Hill advocated the creation of a single "Energy Efficiency Opportunity Fund" to decide how funds can best be spent, perhaps to be managed by the State Energy Office. Piedmont endorsed Chapel Hill's idea and further argued that programs should be evaluated on a total fuel efficiency basis (i.e., source-to-site efficiency plus appliance efficiency).

The electric utilities generally responded that the same arguments were considered in a series of dockets, including Docket No. M-100, Sub 124, which produced the current incentive program rule, R1-38, and the Commission did not accept them then.

The Public Staff stated that the resolution of these issues is beyond the scope of this rulemaking. Senate Bill 3 pertained solely to electric power suppliers and not to natural gas suppliers. The Commission has previously considered destructive competition in incentive programs in the rulemaking leading to the adoption of Rule R1-38. The Public Staff attempted to preserve as much of the rationale behind Rule R1-38 as possible in this rulemaking. The Public Staff did acknowledge that it may be productive to revisit this question in the future.

Historically, the Commission's role has been to prevent the unfair use of participation incentives to build market share by any utility – gas or electric. Arguably, Senate Bill 3 emphasizes the reduction of electric demand. It is clear that both gas and electric utilities see the new statute as potentially enabling them to build market share; however, the statute that forbade destructive competition has not been repealed.

While there may be some merit to the argument that Senate Bill 3 was intended to reduce electric demand, that issue was not fully developed in this electric rulemaking. In addition, the questions of the impact of incentives on inter-fuel competition and total-cycle fuel efficiency are beyond the scope of this rulemaking. Therefore, while the Commission acknowledges the Public Staff's assertion that it may be productive to revisit these issues in the future, the Commission finds good cause to reject proposals to mandate the consideration of other fuels, to create a single efficiency fund and to consider efficiency on a total-cycle basis on the basis that they are beyond the scope of this rulemaking.

ISSUE 63. Definition of "net lost revenues"

Proposed Rule R8-68(b)(5) defines "net lost revenues" as follows:

> "Net lost revenues" means the revenue losses, net of avoided costs, 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 that

> increases customer demand or energy consumption, whether or not that activity has been approved pursuant to this Rule R8-68.

Progress, in its initial comments, proposed that the definition for "net lost revenues" in Rule R8-68(b)(5) should be modified as follows:

> "Net lost revenues" means the non-fuel and fuel related revenue losses~~, net of avoided costs, incurred~~ experienced 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~~ minus any increases in revenues resulting from any activity by the electric public utility that ~~increases~~ causes a customer to increase demand or energy consumption, whether or not that activity has been approved pursuant to this Rule R8-68.

Progress stated that its revisions more clearly reflect the intent of this section, which is to offset lost revenues by revenues the utility realizes from programs that cause customers to increase their use of electricity and to reflect that a utility is not allowed to recover lost revenues associated with costs that the utility avoids due to the DSM and EE program(s).

Duke, in its initial comments, recommended that the definition of "net lost revenues" be changed as follows:

> "Net lost revenues" means the total revenue losses experienced, ~~net of avoided costs, incurred~~ by the electric public utility as a result of a new demand side management or energy efficiency measure, minus~~. Net lost revenues shall also be net of~~ any increases in revenues resulting from specific programs or ~~any activity~~ activities by the electric public utility that causes customers to ~~that~~ increase~~s customer~~ demand or energy consumption, whether or not ~~that~~ the program or activity has been approved pursuant to this Rule R8-68.

Duke remarked that this change is necessary to clarify the intent of this section, which is to offset lost revenues by revenues that the utility realizes from programs that cause customers to increase their use of electricity. Further, Duke commented that it is necessary to delete the language regarding subtracting avoided costs from lost revenue because it incorrectly assumes that avoided costs actually result in cash to the utility. Duke asserted that it does not. Duke explained that avoided cost is a future concept that represents money the utility does not spend, not money it collects. Additionally, Duke contended that, to the extent an electric public utility applies for a recovery mechanism based upon cost, the EE and DSM recovery rule adopted by the Commission should recognize that net lost revenues are a cost incurred by the utility, rather than an incentive.

ED, SACE and SELC, in their initial comments, stated that as identified in subsection (b)(5), net lost revenue calculations must take account of any revenue increases flowing from utility activities that increase electricity consumption (and thus revenues). According to ED, SACE and SELC, this is an appropriate offset.

Wal-Mart, in its initial comments, observed that the definition of “net lost revenues,” as proposed in the October 26, 2007 Order, could allow electric utilities to recover for lost revenues having nothing to do with DSM and EE measures and that was certainly not the intent of Senate Bill 3. Consequently, Wal-Mart proposed that the definition of “net lost revenues” in Rule R8-68(b)(5) be modified as follows:

> “Net lost revenues” means the revenue losses, net of avoided costs, directly incurred by the electric public utility as the result of a new demand-side management or an energy efficiency measure that would not have been made except for said utility efforts. “Net lost revenues” does not mean any other loss in revenues including, but not limited to, losses resulting from individual customer actions, weather variations, general economic conditions, force majeure events, or any other revenue losses that are not the direct 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 that increases customer demand or energy consumption, whether or not that activity has been approved pursuant to this Rule R8-68.

The Public Staff, in its initial comments, suggested that the definition of “net lost revenues” should be clarified to mean 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. Therefore, the Public Staff proposed that the definition for “net lost revenues” in Rule R8-68(b)(5) be modified as follows:

> “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, ~~costs,~~ 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 that increases customer demand or energy consumption, whether or not that activity has been approved pursuant to this Rule R8-68.

ED, SACE and SELC, in their reply comments, agreed that the Public Staff’s proposed modifications make the definition of “net lost revenues” more precise; however, they suggested that the Public Staff’s new phrase “at the time of” might more precisely be rendered by “as a result of.” Conversely, ED, SACE and SELC stated that they do not believe that the rewrite of this same definition, as suggested by Progress, succeeds because it may eliminate the essential step of deducting utility cost savings due to sales losses. According to ED, SACE and SELC, without this deduction, as reflected in the Public Staff’s proposed language, lost revenues would not necessarily be “net.”

ElectriCities, in its reply comments, opposed the Public Staff's proposed modification to the definition of "net lost revenues" and stated that it does not understand what the Public Staff means by marginal costs avoided. ElectriCities supported the initial comments of Duke regarding Duke's modification to the definition of "net lost revenues."

Duke, Dominion and Progress jointly filed reply comments stating that, in considering the proposed EE and DSM rules, the Commission should recognize that as energy savings increase, electricity sales will diminish (as will generation additions). Thus, Duke, Dominion and Progress took the position that it is important that the regulatory models mitigate or neutralize the financial consequences resulting from the successful implementation of EE programs that reduce energy. Duke, Dominion and Progress remarked that the Commission's proposed Rules R8-68 and R8-69 do so by providing recovery of "net lost revenues." However, to properly address the impact of energy savings on utility revenues, Duke, Dominion and Progress asserted that the definition of net lost revenues must be appropriate.

Duke, Dominion and Progress stated that the definition of "net lost revenues" proposed by Duke and Progress is the most accurate and clear definition, whereas, other proposed definitions attempt to introduce the concept of the utility's avoided cost. However, Duke, Dominion and Progress remarked that the costs that a utility avoids are predominantly fuel costs. Duke, Dominion and Progress opined that, if a fuel cost is not incurred, then it is not reflected in the utility's fuel cost recovery rider and there is no reason to address this issue in the definition of "net loss revenues" if the definition is based upon lost non-fuel revenues, as proposed by Duke and Progress.

CIGFUR, in its reply comments, agreed with the Public Staff's proposal to revise the definition of "net lost revenues." CIGFUR stated that the Public Staff's definition appears to add clarity, whereas the proposal by Progress appears to increase potential lost revenues.

CPV, in its reply comments, addressed the issue of how it thought the calculation of avoided costs under proposed Rule R8-67 should be performed and, within that discussion, CPV mentioned the Public Staff's proposed change in the definition of "net lost revenues." CPV observed that in the definition of "net lost revenues" the Public Staff proposes the use 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." CPV opined that the degree of complexity involved in calculating the marginal cost of a kilowatt-hour not sold does not appear to be so great as to prevent the use of real time marginal avoided costs or billing period avoided costs to calculate incentive payments due to utilities.

Nucor, in its reply comments, stated that the Commission should reject the proposal of Progress to modify Rule R8-68(b)(5) to remove the reference to net avoided costs. Nucor asserted that, in measuring net lost revenue, the Commission must take into account the utility's avoided costs, or the utility is likely to be substantially overcompensated for its lost revenues.

Nucor stated that the Commission's proposed Rule R8-68(b)(5) defines "net lost revenues" as "the revenue losses, net of avoided costs, incurred by the electric public utility as the result of a new demand-side management or energy efficiency measure." Nucor observed that, under the Commission's proposed Rule R8-69(c)(1), a public utility may apply for recovery of net lost revenues related to new DSM or EE measures in its annual rider proceeding, and the utility bears the burden of proof, as to the amount of net lost revenues and the reasonableness and prudence of the inclusion of a particular amount of net lost revenues in the rider. In regard to the Commission's proposed Rule R8-69(c)(2), Nucor stated that, under that subsection, an electric public utility shall not be permitted to earn a return on net lost revenues unless the Commission approves an annual rider that provides for recovery of an integrated amount of recoverable costs and net lost revenues.

Nucor explained that Progress has proposed to eliminate proposed Rule R8-69(c) in its entirety and to modify proposed Rule R8-69(b)(1) to require the Commission to allow utilities to recover net lost revenues. Nucor opined that Progress has revised the rules to make approval of the recovery of net lost revenues mandatory rather than discretionary. In addition, Nucor stated that recovery of a return on net lost revenues would be mandatory under Progress's proposed changes, rather than discretionary under Rule R8-69(c).

Nucor requested that the Commission reject Progress's proposed changes. Nucor pointed out that Progress assumes utilities are entitled to recover net lost revenues as a result of DSM and EE. However, Nucor asserted that it is part of the regulatory compact that utilities should keep their costs as low as reasonably possible. Also, Nucor observed that, from a customer's perspective, these net lost revenues are actually savings brought about by the actions of customers, such as altering their electricity consumption patterns or installing more energy efficient equipment. Thus, Nucor maintained that it should not be a "given" that a utility is allowed to recover net lost revenues (not to mention a return on such net lost revenues). Instead, Nucor contended that the Commission should consider how net lost revenues ought to be treated on a case-by-case basis to ensure that both utilities and their customers are treated fairly.

Further, Nucor observed that, unlike Progress's proposed revisions, the Commission's proposed Rule R8-69(c), as currently drafted, provides for a balanced approach to net lost revenues by allowing utilities to request cost recovery for net lost revenues, including a return on net lost revenues, but leaving it up to the Commission to decide whether and how to allow recovery of net lost revenues through the utility's DSM and EE rider. Nucor explained that, under the Commission's approach, the utility will bear the burden of proof to show the reasonableness and prudence of the inclusion of net lost revenues in the amount to be recovered through the rider, and the Commission and all parties will have the opportunity to challenge the inclusion of net lost revenues in the utility's annual DSM and EE proceeding. Nucor maintained that this will allow the Commission to balance the interests of the utilities and the customers with respect to the recovery of net lost revenues.

PSNC, in its reply comments, stated that Duke is interpreting "net lost revenues" under the existing regulatory paradigm, which does not comply with the requirements of Senate Bill 3. PSNC contended that, under the new statutory provisions, electric power providers may not file under R8-68 and R8-69 for Commission approval of and cost recovery for incentives which increase electric demand. Thus, PSNC asserted that Duke's interpretation assumes the inclusion of load building measures that are not permissible under the new statutory provisions.

The Attorney General, in his reply comments concerning Rules R8-68 and R8-69, observed that the Commission may allow utilities to recover an amount in the annual rider for net lost revenues experienced by utilities in order to encourage DSM and EE programs, but net lost revenues are incentives, not costs.

The Attorney General stated that Duke's position is that the Commission's rules governing a utility's recovery of costs associated with DSM and EE programs should treat net lost revenues as a cost incurred by the utility rather than as an incentive. The Attorney General pointed out that Duke contends that, under Senate Bill 3, "costs" shall be recoverable unless they are found by the Commission to have been unreasonably and imprudently incurred, and Progress agreed with Duke. While the Attorney General does not oppose provisions in the proposed rules that allow utilities to apply for recovery of net lost revenues when particular new DSM or EE programs are proposed, the Attorney General believes that net lost revenues are not costs; instead, they are incentives, with the appropriateness of allowing their recovery in the annual rider being a matter that is left to the Commission's discretion. If the proposed rules suggest otherwise, the Attorney General remarked that they should be clarified on this point.

The Attorney General observed that Senate Bill 3 states, in language codified at G.S. 62-133.8(d), that the Commission shall, upon petition, approve a rider for recovery of reasonable and prudent costs and, in determining the amount of the rider, may approve incentives for utilities to pursue new DSM and EE measures. G.S. 62-133.8(d) also states that recoverable costs "include, but are not limited to, all capital costs, including cost of capital and depreciation expenses, administrative costs, implementation costs, incentive payments to program participants and operating costs."

The Attorney General also observed that the term "net lost revenues" is not mentioned in the statute as a recoverable cost and is not an expense or investment item comparable to those that are mentioned. The Attorney General argued that net lost revenues are better characterized as missed sales opportunities associated with DSM and EE programs that may discourage utilities from undertaking ambitious measures to promote EE and other DSM options. The Attorney General reasoned that, by allowing recovery of net lost revenues in conjunction with particular EE programs, the utility would be allowed to take back some of the benefit of energy savings that are brought about by the utility's measures as an incentive to promote wise rather than wasteful use of energy. The Attorney General explained that, likewise, if net lost revenues occur in conjunction with DSM programs, there might be a justification for allowing their recovery to encourage development of DSM programs.

Next, the Attorney General asserted that the treatment of net lost revenues as incentives rather than costs is consistent with what the Commission has done historically. The Attorney General explained that the history of DSM programs that have been funded in the past was discussed in the Order Approving Integrated Resource Plans and Requiring Additional Information in Future Reports, issued August 31, 2006, in the 2005 IRP Proceeding, Docket No. E-100, Sub 103, which drew mainly from testimony presented by former Commissioner Dr. Julius Wright on behalf of Duke, Progress and Dominion. According to the Attorney General, Dr. Wright characterized the recovery of lost sales revenues as a type of incentive mechanism that has been allowed by the Commission. (Direct Testimony of Julius A. Wright, Ph.D. filed June 5, 2006 at Page 22.) The Attorney General also noted that Dr. Wright described the DSM funding mechanism proposed in a stipulation in Duke's 1991 rate case in Docket No. E-2, Sub 487, which allowed Duke to seek deferral of net lost revenues associated with particular programs for recovery in its next rate case.

Further, the Attorney General stated that the notion that utilities are entitled to "lost revenues" as costs has the potential to add increments to rates that are unjustified and overly burdensome. The Attorney General suggested that the Commission should consider the impact if utilities had been found to be entitled to hypothetical "lost revenues" for providing peak shaving DSM programs and time-of-use rates over the past decades. The Attorney General observed that the utilities have avoided construction of peaking plants by encouraging customers to shift load to off-peak times without any reduction in energy consumption. The Attorney General noted that such measures have encouraged the efficient use of facilities and that consumers might pay significantly higher rates if utilities had been found to be entitled to recovery for "lost revenues" resulting from the adoption of such measures. The Attorney General explained that, if utilities seek recovery of an increment in the annual rider for "net lost revenues" associated with new peak shaving programs pursuant to G.S. 62-133.8(d), the justification for that incentive should be considered by the Commission when the program is proposed. The Attorney General asserted that the utilities are not entitled to such recovery pursuant to Senate Bill 3.

Moreover, the Attorney General observed that no one contends that there is a need for utilities to recover net lost revenues in the annual rider because consumption is expected to decline so much and so quickly that utilities will not otherwise have an opportunity to recover their revenue requirement. The Attorney General pointed out that, while decreased sales that result from EE programs could reduce gross revenues, the decrease can be expected to be offset fully or in part by continued growth trends in customer count and per customer usage in North Carolina. Moreover, the Attorney General remarked that, if a utility anticipates that EE and DSM programs combined with other developments affecting cost of service will cause an under-recovery of revenues, it can file a rate case.

The Attorney General suggested that the impact of new DSM and EE programs and measures on revenues can be expected to be short term, given that any longer term reduction in consumption brought about by such programs will be taken into account when costs are spread over fewer kilowatt-hours in subsequent rate cases. To the extent that consumption is reduced through utility programs, the Attorney General noted that most savings would eventually be achieved through other means; and gains in EE would likely have a useful life (e.g., energy star appliances wear out eventually, and caulking must be redone over time).

Furthermore, the Attorney General acknowledged that defining and quantifying net lost revenues will not be a straightforward determination and may be contentious. The Attorney General noted that it is not clear from the definition of "net lost revenues" how much a utility will be allowed to reflect in the annual rider and for how long. For example, the Attorney General queried that, if an EE program results in savings of 10,000 kilowatt-hours in one year because 100 customers caulk their windows and add insulation three years sooner than they would have without the utility program, would the associated net lost revenues be counted for all three years and recovered over three years? The Attorney General also queried how much of the savings would be attributed to the utility program and how much to the customer if the program splits the cost of efficiency improvements by providing a 25% rebate?

Additionally, the Attorney General observed that it is also unclear from the definition of net lost revenues what costs must be netted out to determine the recoverable amount. However, the Attorney General agreed with the Public Staff that two sorts of netting out should occur to avoid over-recovery by utilities for net lost revenues. The Attorney General explained that, first, any costs that are avoided by the utility as a result of missed sales of kilowatt-hours related to utility programs, such as reduced marginal fuel costs and uncollectible expenses, would produce a windfall if the utility were allowed to recover lost revenues without netting out such avoided expenses; and second, increases in consumption encouraged by utility programs, such as a customer's switch from a natural gas furnace or water heater to a high efficiency electric heat pump or water heater, should be reflected as an offset.

For the foregoing reasons, the Attorney General recommended that the proposed rules allow the recovery of net lost revenues as an incentive, but not as a cost. The Attorney General suggested that the rules should be clarified to characterize net lost revenues as a type of incentive that may be recovered pursuant to G.S. 62-133.8(d)(2), assuming that recovery is found to be appropriate. The Attorney General stated that the utility should have the burden of proof on the amount of "net lost revenues," with respect to the public interest issue, and with respect to the reasonableness and prudence of including net lost revenues in the rider. The Attorney General suggested modifications to make these points clearer in proposed Rules R8-68(c)(2)(iii)(c), R8-68(c)(vi), R8-69(c)(1), R8-69(d), and R8-69(g)(1)(iv).[6]

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[6] In referring to proposed Rule R8-68(c)(2)(iii)(c), the Attorney General actually appears to be referring to proposed Rule R8-68(c)(3)(ii)(b) in the October 26, 2007 Order or Rule R8-68(c)(3)(ii)(c) in Appendix A of the Public Staff's November 14, 2007 initial comments. Similarly, in referring to proposed Rule R8-68(c)(vi), the Attorney General actually appears to be referring to R8-68(c)(3)(vi) in the Commission's October 26, 2007 Order.

The Public Staff, in its reply comments, noted that both Duke and Progress proposed to revise the definition of "net lost revenues" to essentially read as follows:

> "Net lost revenues" means the total revenue losses experienced by the electric public utility as a result of a new demand side management or energy efficiency measure, minus any increases in revenues resulting from specific programs or activities by the electric public utility that causes customers to increase demand or energy consumption, whether or not that activity has been approved pursuant to this Rule R8-68.

The Public Staff argued that its proposed definition for net lost revenues is appropriate, as follows:

> "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 that increases customer demand or energy consumption, whether or not that activity has been approved pursuant to this Rule R8-68.

The Public Staff stated that it is not disputing that the utility should be allowed to recover net lost revenues, provided that the utility demonstrates the amount, as well as the reasonableness and prudence, of the inclusion of such an amount in the rider. The Public Staff agreed that net lost revenues are not a utility incentive by definition. However, the Public Staff also stated that it does not believe that recovery of net lost revenues is automatic. The Public Staff maintained that its proposed definition of "net lost revenues" is reasonable and appropriate.

For the reasons generally given by the Attorney General, the Commission concludes that net lost revenues are not a cost but, instead, a type of utility incentive that may be recovered in an annual rider pursuant to G.S. 62-133.8 (d)(2), assuming that recovery is found to be appropriate by the Commission. The Commission believes that it is clearly appropriate for the Commission to retain the discretion to determine the appropriate level of net lost revenues that may be recovered in an annual rider. The Attorney General did not propose any clarification in the proposed definition of net lost revenues. However, the Commission is of the opinion that the definition should be modified to include, in part, certain changes proposed by the Public Staff, Progress, and Duke.

Regarding the Public Staff's proposed modification to the first sentence of the definition, the Commission agrees with its proposal to change the phrase "net of avoided costs" such that the definition of "net lost revenues" would mean 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". Regarding Progress and Duke's proposed modification in the second sentence, only as it relates to a clarification of the phrase “any activity that increases customer demand or energy consumption”, the Commission concludes that this phrase should be changed to refer to “any activity by the electric public utility that causes a customer to increase demand or energy consumption”. The Commission is of the opinion that these modifications more clearly and appropriately describe what should be netted out in developing the amount of net lost revenues that may be recoverable.

Accordingly, the Commission finds that the definition of “net lost revenues”, which should be adopted for inclusion in Rule R8-68(b)(5), is as follows:

> “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.

ISSUE 64. Definition of “participation incentive”

Rule R8-68(b)(7) provides the definition of “participation incentive.”

Dominion observed that the definition of “participation incentive” in Rule R8-68(b)(7) did not include studies on energy usage. Dominion considers a follow-up report from an audit program to be a participation incentive.

The Public Staff expressed concern that “studies on energy usage” is an overly broad term that could encompass mere customer surveys on energy usage as well as predominantly promotional or comparative materials that also contain a “study” component. The Public Staff maintained that costs for such activities should not be recoverable through the annual rider because they do not constitute a DSM or EE measure as defined in G.S. 62-133.8. However, the Public Staff pointed out that the type of follow-up from an audit that Dominion cites as an example of an energy study could be tailored to further specific new EE or DSM activities. If so, the Public Staff would not oppose the recovery of costs associated with such programs in the rider. The Public Staff proposed the following addition to Rule R8-68(b)(7):

> Studies on energy usage are not “participation incentives” unless they result from an audit of energy usage by a customer or customers and are designed to result in new energy efficiency or demand-side management measures. Energy usage studies that are promotional shall not be considered participation incentives. The burden of showing that an energy usage study should be considered a participation incentive is on the electric power supplier.

The Commission acknowledges that some types of studies or audits may qualify as a participation incentive. Specific decisions would need to be made on a case-by-case basis. Therefore, the Commission concludes that the sentence, "'Participation incentive' does not include studies on energy usage," should be removed from Rule R8-68-(b)(7).

ISSUE 65. Costs and benefits provision

Rule R8-68(c)(2)(iii) discusses the "costs and benefits" subsection of the filing requirements.

In their comments, ED, SACE and SELC stated that "costs" should be listed in more detail in subsection (c)(2)(iii)(a). In order to focus subsection (a) more fully on costs, the terms "benefit" and "benefits" should be removed. As used in proposed subsection (c)(2)(iii), "benefit" has the same meaning as "consideration." Therefore, if it is used, the term "benefit" should be used in subsection (b) only. The resulting paragraph proposed by ED, SACE and SELC would read:

> (iii) 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 of the measure or program to the electric public utility or electric membership corporation, reported by type of cost (<u>e.g.</u>, capital cost expenditures, administrative costs, operating costs, and participation incentives, including rebates and direct payments, and advertising) and the planned accounting treatment for those costs, (b) the type, amount, and reason for any participation incentives and other consideration and to whom these benefits will be offered, including schedules listing participation incentives or other consideration to be offered, and (c) service limitations or conditions planned to be imposed on customers who do not participate in the measure.

The Public Staff did not object to a fuller listing of the types of costs involved and proposed a revision to the proposed rule in its reply comments. The Public Staff's revision adds the following wording to subsection (a) after type of benefit and expenditure: "capital cost expenditures, administrative costs, operating costs." The Public Staff argued that no other changes to this section are necessary. Rule R8-68(a)(7) defines "participation incentives" to be the same as "consideration" (with the exception of studies on energy usage), not benefits, for purposes of program approval. The rule does not define "benefit." The Public Staff asserted that the rule refers to the "benefit" that a customer may derive as a result of an EE measure. For example, the deferral of the building of a base load plant is a benefit that customers may derive from an EE or DSM measure. Benefits, therefore, can be broader than the "participation incentives" that a participant receives to participate in a program.

The Commission finds good cause to accept the Public Staff's additional clarifying language and reject the additional wording of ED, SACE and SELC for the reasons advanced by the Public Staff.

ISSUE 66. Cost-effectiveness tests

Rule R8-68(c)(2)(iv) describes the cost-effectiveness evaluation portion of the filing requirements.

ED, SACE and SELC suggested that care should be taken in applying the TRC test to comprehensively identify the avoided cost benefits of EE and DSM. Specifically, avoided cost benefits that may also be external to the utility system but are real should be identified and accounted for, an approach sometimes called the "societal" variant of the TRC test. ED, SACE and SELC argued for adding the following sentence at the end of (c)(2)(iv):

> In applying the TRC test, consideration should be given to quantifying, to the extent feasible, avoided resource benefits that lie outside the electric utility system, such as collateral reductions in non-electric energy use, water resources, or environmental impacts.

The Public Staff asserted that, by requiring consideration "to the extent feasible," this sentence tends to conflict with the preceding requirement that cost effectiveness evaluations be based on direct and quantifiable costs and benefits. Therefore, the Public Staff did not support the addition of this sentence to Rule R8-68(c)(2)(iv).

The Commission agrees with the Public Staff that the additional language requested by ED, SACE and SELC should not be inserted in the Rule. These types of issues may be argued in specific incentive program proceedings, if warranted.

According to the Attorney General, proposed Rule R8-68(c)(2)(iv) states that the utilities must, at a minimum, use the Total Resource Cost (TRC) test and Ratepayer Impact Measure (RIM) test to evaluate the cost-effectiveness of EE programs. However, the proposed rule does not specify how the tests should be used, such as whether the results of the various tests should be given equal weight or whether an EE program's failure to pass a particular test eliminates it from consideration.

The Attorney General maintained that there is no consistency in the manner in which North Carolina's electric utilities assess the cost-effectiveness of EE measures. This lack of consistency makes it difficult for consumers and other analysts to understand why utilities choose certain EE programs and reject others. Yet, the more that consumers understand EE program choices and have confidence that they are made on some rational basis, the more consumers will support EE programs. The Attorney General argued that, given the heightened importance of EE under Senate Bill 3, the Commission should correct this lack of consistency in the selection and implementation of EE measures.

The Attorney General further observed that the Commission has accepted use of the RIM test in past proceedings, but has not expressly approved the RIM test, or any other cost-benefit test, as the best means to measure cost-effectiveness. The Commission should provide specific direction on which tests to use and how to use them. In doing so, it should be guided by three fundamental principles. First, the tests should be uniform and applied consistently by all companies. Second, the tests should measure the relevant factors, which are the costs and benefits of the particular program. Third, to the extent that a test allocates costs and benefits among customer classes, it should include full recognition of the benefits received by all customer classes.

In conclusion, the Attorney General explained that, to establish guidelines for use of the various tests, the Commission may need more information than can be provided in comments and reply comments. If so, the Attorney General would welcome the opportunity to participate in a collaborative workshop or evidentiary hearing concerning these issues.

Nucor agreed with the Attorney General that guidelines concerning how the tests should be used are necessary. No one test listed in Rule R8-68(c)(2)(iv) tells the whole story. The rule should also be clear that the Commission will consider other facts and circumstances in determining the cost effectiveness of a DSM or EE measure instead of focusing only on the results of the various tests. Nucor stated that, in addition to establishing guidelines as the Attorney General suggests, the Commission should also modify Rule R8-68(c)(2)(iv) by adding the following language at the end of the rule: “The Commission will consider the results of these tests, in addition to all facts and circumstances regarding a particular incentive program, in determining the cost-effectiveness of the incentive program.”

The Public Staff did not support a revision to the proposed Rule R8-68(c)(2)(iv). Additional information, as well as increased experience with the cost-effectiveness tests will undoubtedly assist the Commission in its upcoming review of DSM and EE programs. The Public Staff further notes that the IRP plans will contain information regarding the electric utility’s “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.” These overall assessments should provide the Commission and the parties with further information concerning the application of the cost-effectiveness tests. Therefore, the Public Staff took the position that a revision to Rule R8-68 regarding application of the tests is unnecessary at this time.

The Public Staff agreed with Nucor’s position that the Commission should exercise its own judgment in reviewing the cost-effectiveness of the programs, but did not believe that such language needs to be included in the rules for the Commission to do so. The totality of the information required for approval of a DSM or EE program shows that the Commission will consider a great deal of information in addition to simply the results of cost-effectiveness tests in determining whether to approve a DSM or EE program.

For the reasons noted by the Public Staff, the Commission concludes that no additional language or guidelines should be added to Rule R8-68(c)(2)(iv) at this time. The Commission continues to uphold its traditional position on this issue, which is that utilities are obligated to consider the results of multiple cost-effectiveness tests and that any needed cost-effectiveness determinations will be based on the totality of the relevant circumstances.

ISSUE 67. Spending on communications materials

Rule R8-68(c)(2)(v) discusses cost information for communications materials related to each proposed measure or program.

Dominion stated that it will use market research to evaluate DSM programs and to prepare load forecasts for its IRP model. It would like clarification that "communication materials" for which recovery will be permitted includes, but is not limited to, market research, advertising, direct mail, bill inserts, and surveys by mail or phone.

The Commission concludes that the issue of what specific communications-related costs are recoverable under the DSM/EE rider is not appropriately addressed in this rulemaking proceeding but rather in the context of a request for approval of a specific EE measure or DSM/EE rider. Therefore the Commission finds it appropriate to retain the original wording of subsection (c)(2)(v).

ISSUE 68. Add guidelines as appendix to Chapter 8 of Commission's rules

Proposed Rule R8-68(c)(2)(vi) references the Revised Guidelines for Resolution of Issues Regarding Incentive Programs issued by Commission Order on March 27, 1996, in Docket No. E-100, Sub 71.

In its reply comments, the Public Staff stated that it had learned through discussions with the parties that it would eliminate some confusion if the "Revised Guidelines Regarding Incentive Programs" referred to in Rule R8-68(c)(2)(vi) are attached as an Appendix to Chapter 8 for the parties' convenience. The Public Staff had no objection to this proposal. It requested that the Commission attach the Revised Guidelines Regarding Incentive Programs as an Appendix to Chapter 8 of the Commission's rules.

In their joint reply comments, Duke, Progress and Dominion similarly stated that, if proposed Rule R8-68(c)(2)(vi) is going to require compliance with the Incentive Program Guidelines, the utilities believed that they should be published and attached to the Rule itself. They argued that the best way to ensure compliance with the law is to ensure it is clearly presented for all to read.

The Commission concludes that it would be beneficial, in light of the State's renewed emphasis on energy efficiency, to include the Guidelines in Chapter 8 of the Commission's rules for ease of reference by all parties and to revise

Rule R8-68(c)(2)(vi) accordingly. The Commission further finds good cause to revise the Guidelines consistent with the other rules adopted herein.

The Commission's March 27, 1996 Order was, in fact, issued in both Docket Nos. E-100, Sub 71 and M-100, Sub 124, and the Guidelines were made applicable to both electric and to natural gas utilities. The Commission, therefore, finds it appropriate to also add a reference to the Guidelines and the Appendix to Chapter 8 in Rule R6-95.

ISSUE 69. Approval of "modified" DSM or EE programs and two additional subparagraphs

Rule R8-68(c)(3) describes additional filing requirements relating to an application for approval of a DSM or EE program.

In Rule R8-68(c)(3), the Public Staff argued that an electric public utility filing for approval of new DSM or EE programs should also file for approval of "modified" DSM or EE programs. While only "new" programs qualify for cost-recovery pursuant to G.S. 62-133.8, the Public Staff maintained that it would be helpful to review proposals to modify programs to determine the degree of modification.

Additionally, the Public Staff requested the addition of subparagraphs k. and l. to Rule R8-68(c)(3)(i) to reflect some best practices approved by the North American Energy Standards Board (NAESB) with regard to measurement and verification.

The Commission finds good cause to accept the Public Staff's proposed additions. In addition, the Commission concludes that the words "or modified" should be added to section (c)(1)(i) for consistency.

ISSUE 70. Clear demonstration of customer class costs

Rule R8-68(c)(3) discusses additional filing requirements associated with an application for approval of a DSM or EE program.

CUCA argued that the "additional filing requirements" need to include information about customer class-specific costs and benefits to allow the parties to assess the utility's compliance with G.S. 62-133.8(e). In its reply comments, CIGFUR offered support for CUCA's proposal.

NCFB also asserted that the application should require a clear demonstration of the costs and benefits for each customer class. G.S. 62-133.8(e) allows cost assignment only to the affected class or classes of customers. "Customer class" should be clearly defined either by Commission rule or by the utility. Agricultural customers are spread throughout the traditionally defined customer classes (i.e., residential, commercial, industrial). Without a clear definition of "customer class," agricultural customers cannot accurately assess whether they directly benefit from a specific DSM or EE program.

The Public Staff did not support either of the above recommendations. Proposed Rule R8-68(c)(3) already provides that, with regard to costs and benefits, the electric utility filing for approval of a DSM or EE program shall additionally show "how [it] proposes to allocate the costs and benefits of the measure among the customer classes and the jurisdictions it serves." It requires the electric utilities to provide a great deal of information in applying for approval of new DSM and EE programs and measures. The Public Staff maintained that the required information is sufficient to comply with G.S. 62-133.8. Moreover, the proposed rule allows the Commission to determine these issues on a case-by-case basis. It appears difficult to craft an overarching rule that will satisfy all parties and apply in all cases.

While the Commission understands the concerns of CUCA and NCFB on this issue of customer class-specific costs and benefits, it will not add additional wording to the Rule at this time. If the filings do not contain enough specific information, the parties, as well as the Commission, can request additional information relating to customer class-specific costs and benefits.

ISSUE 71. Documenting net environmental emissions impacts

Rule R8-68(c)(3)(i) describes additional filing requirements relating to an application for approval of a DSM or EE program.

ED, SACE and SELC asked that the rules require the documenting of net environmental emissions impacts and, in support of that request, noted that carbon emissions may at some near point have a monetary cost. The Public Staff responded that amendment of the rules is appropriate if that occurs, but is not necessary at this point.

The Commission finds good cause to conclude that the rules do not need to address the issue of net environmental emission impacts at this time. The Commission finds that the goals of Senate Bill 3 can best be fulfilled by focusing on the development of renewable energy technologies and energy efficiency within the cost constraints set out by the statute.

ISSUE 72. Additional filing requirement to include information on costs incurred or expected to be incurred

Rule R8-68(c)(3)(ii) sets forth filing requirements, specifically with regard to costs and benefits, relating to an application for approval of a DSM or EE program.

In its initial comments, the Public Staff stated that it proposed to add language to Rule R8-68(c)(3)(ii) requiring a utility to include in its application information regarding "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. 62-133.8." The Public Staff stated that this language was proposed "[i]n recognition that the electric public utilities may incur costs for a program prior to its approval by the Commission." This amendment would allow a utility to describe any costs it had previously incurred in adopting and implementing the program that it planned to seek to recover under Rule R8-69 and G.S. 62-133.8. The Public Staff stated that it understood that the electric public utilities potentially may want to begin to defer costs prior to Commission approval of a measure or program.

In their reply comments, ED, SACE and SELC noted that both the Public Staff and Progress recognized that some EE and DSM program development costs may be incurred prior to program approval. In its new R8-68(c)(3)(ii)a, the Public Staff only proposed that utilities may identify such costs. By contrast, Progress would add broad language to Rule R8-69(b)(4) to permit deferred accounting for both specific program development costs and very general EE and DSM activity costs. ED, SACE and SELC stated that it is important that utilities not be discouraged from developing robust and well-founded EE and DSM program proposals to submit to the Commission for potential approval. For this reason, they cautiously supported Progress's proposal here, provided that it can be limited to costs that are directly linked to programs that are subsequently approved.

The Commission concludes that the additional information sought by the Public Staff will be helpful and that it should be included in Rule R8-68(c)(3)(ii).

ISSUE 73. Filing requirement to describe costs and benefits, including net lost revenues

Proposed Rule R8-68(c)(3)(ii) concerns the "Costs and Benefits" an electric public utility shall describe in its application. The Attorney General, in his reply comments, recommended that Rule R8-68(c)(3)(ii)(b)[7] be modified as follows:

> estimated <u>utility incentives, e.g., estimated</u> net lost revenues by appropriate capacity, energy and measure unit metric and in the aggregate by year;

No other party explicitly commented on this issue.

Consistent with the Commission's prior discussion and conclusions regarding the proper definition of "net lost revenues" in Rule R8-68(b)(5), wherein it concluded that net lost revenues are a type of utility incentive that may be recovered in an annual rider, if appropriate, the Commission concludes that proposed Rule R8-68(c)(3)(ii)(b) should be deleted rather than modified as proposed by the Attorney General. However, the Commission finds good cause to incorporate the substance of the Attorney General's

[7] The Attorney General, in his reply comments, referenced this rule as R8-68(c)(2)(iii)(c); however, the Attorney General appears to be actually referring to proposed Rule R8-68(c)(3)(ii)(b) in the October 26, 2007 Order or Rule R8-68(c)(3)(ii)(c) in the Public Staff's Appendix A attached to its initial comments filed November 14, 2007.

proposal in Rule R8-68(c)(3)(vi), which concerns additional filing requirements regarding requested utility incentives that must be provided by an electric public utility filing for approval of a new or modified DSM or EE measure. The Commission, therefore, finds that proposed Rule R8-68(c)(3)(vi) should be modified to include as a new last sentence the following:

> 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.

ISSUE 74. Requirement for all models for measuring and charging for efficiency to be routinely verified and audited

Proposed R8-68(c)(3)(iii) states in part:

> 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. If the electric public utility plans to utilize an independent third-party for purposes of measurement and verification, an identification of the third-party and all of the costs of that third-party should be included. The costs of implementing the measurement and verification process may be considered as operating costs.

NC WARN noted that R8-68(c)(3)(iii) entrusts the utility companies with responsibility for devising models to measure and charge for efficiency. It argued that the proposed rule does not require the companies' calculations to be verified or audited by independent third parties. At least initially, the Commission should carefully scrutinize all models and have them routinely verified and audited.

The Commission concludes that it is reasonable to expect that the Public Staff and other parties will review the effectiveness of utilities' methodologies for measuring and verifying energy and demand savings. The Commission finds that the rules do not need to direct how the necessary review should be conducted.

ISSUE 75. Measurement and verification for utility incentives; third party audits

Rule R8-68(c)(3)(iii) and (vi) describe measurement and verification procedures for new DSM and EE measures.

In NC WARN's comments, it noted that the Commission entrusts the utility companies with responsibility for devising models to measure and charge for efficiency. It does not require the utility companies' calculations to be verified or audited by independent parties, but rather assumes that other parties will work from the utility companies' models in order to reach a decision. As the Commission stated elsewhere, the rules can be amended, but at least initially as the programs develop, the Commission should carefully scrutinize all models and have them routinely verified and audited. NC WARN's underlying concern is that the energy efficiency models may be similar to the "black box" models used in the IRP proceedings that may be subject to manipulation to achieve various outcomes.

ED, SACE and SELC responded that measurement and verification (M&V) of the effects of EE and DSM are important, as appropriately recognized by proposed R8-68(c)(3)(iii). They argued that if a utility wishes to file and receive approval for an incentive in addition to its costs, the importance of M&V increases further. Specifically, they suggest that, when a utility files for an incentive, the Public Staff should retain an independent third party to either establish the results of EE or DSM for the utility or to independently assess the utility's claimed results. This requirement could be included in Rule R8-68 or R8-69. If included in R8-68(c)(3)(vi), it could read as follows:

> (vi) 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 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 is required to describe the incentives it desires to recover and describe how its measurement and verification plan will demonstrate the results achieved by the proposed measure. If the electric public utility proposes recovery of utility incentives, its measurement and verification plan must include provision for the Public Staff to procure independent third party measurement and verification services, at the expense of the electric public utility, in lieu of or in addition to measurement and verification the utility proposes to conduct itself.

The Public Staff wholeheartedly supported the suggestion that it have the authority to procure independent third-party M&V services. Nevertheless, it did not read the proposed rules to preclude its retention of an independent third party, and it took the position that the Commission and the parties involved could better address this question on a case-by-case basis. The Public Staff, therefore, supported the retention of a third party to assist in the evaluation of program measurement and verification, but does not support the proposed addition to Rule R8-68(c)(3)(vi).

The Commission concludes that this issue should be addressed on a case-by-case basis and that no change should be made to the rules. The Public Staff already has authority under G.S. 62-15(h) to hire expert assistance and to have the affected electric public utility pay the costs.

ISSUE 76. Description of utility incentives to include net lost revenues

Progress, in its initial comments, proposed that the additional filing requirements relating to utility incentives, Rule R8-68(c)(3)(vi), should be modified as follows:

> 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 in addition to its costs <u>and net lost revenues</u>. If the electric public utility proposes recovery of utility incentives related to the proposed new demand-side management or energy efficiency measure, it is encouraged, but not required, to describe the incentives it desires to recover and describe how its measurement and verification reporting plan will demonstrate the results achieved by the proposed measure.

Progress stated that the net lost revenues are not considered an incentive.

The Attorney General, in his reply comments, recommended that Rule R8-68(c)(3)(vi) be modified as follows:

> 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 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 ~~is encouraged, but not required, to~~ <u>shall</u> describe the incentives it desires to recover and describe how its measurement and verification reporting plan will demonstrate the results achieved by the proposed measure.

The Public Staff, in its reply comments, noted that Progress also argued that “net lost revenues” should be added to Rule R8-68(c)(3)(vi) because that section discusses what a utility may recover in addition to utility incentives, and net lost revenues are not a utility incentive. The Public Staff agrees that net lost revenues are not a utility incentive by definition. However, the Public Staff stated that it does not believe that recovery of net lost revenues is automatic. Nevertheless, the Public Staff observed that the purpose of this subsection is not to define what a utility may recover, but instead to require the utility to indicate whether it will subsequently seek recovery of utility incentives. Therefore, the Public Staff stated that it would agree that Rule R8-68(c)(3)(vi) could be modified to read in pertinent part:

> 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 in addition to its costs <u>and, if appropriate, net lost revenues</u>.

Consistent with the Commission’s prior discussion and conclusions regarding the proper definition of “net lost revenues” in Rule R8-68(b)(5), in which it concluded that net lost revenues are a type of utility incentive that may be recovered in an annual rider, if appropriate, the Commission rejects Progress’s and the Public Staff’s proposed modifications. The Commission agrees with the Attorney General’s proposed recommendation to the effect that, if the electric public utility proposes recovery of utility incentives related to a proposed new DSM or EE measure, it <u>shall</u> describe the incentives it desires to recover. Furthermore, as discussed previously, the Commission has also found that an additional sentence should be added to this rule requiring the utility to describe estimated net lost revenues by appropriate capacity, energy and measure unit metric and in the aggregate by year. Accordingly, the Commission finds that Rule R8-68(c)(3)(vi) should be modified such that it is worded, in its entirety, as follows:

> 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.

ISSUE 77. Filing of alternative DSM or EE programs

Rule R8-68(d) describes the procedure for filing DSM and EE measures and programs for approval.

The Public Staff proposed to revise R8-68(d) to allow for a broader scope of involvement by interested parties in the approval process for DSM and EE measures and programs. Under the Public Staff's proposal, if an electric public utility submits a DSM or EE program or measure for approval, any person may file an alternative DSM or EE program or measure or an evaluation of the electric public utility's proposed DSM or EE measure in addition to a protest pursuant to Commission Rule R1-6. In this respect, this proposed rule is similar to the IRP rule, Rule R8-60, which allows intervenors to file their own IRPs in response to the electric utilities' IRPs.

ED, SACE and SELC replied that, all else being equal, broader involvement of interested parties in EE and DSM approval processes should strengthen the effectiveness of the measures and programs ultimately approved and implemented. Therefore, they supported the Public Staff's proposal.

The purpose of a proceeding pursuant to Rule R8-68 is to determine whether to approve a specific DSM or EE measure or program proposed by the utility. Participation by other parties in this proceeding should be limited to whether or not the Commission should approve the proposed program. A party may offer comments or objections to the DSM or EE measure or program proposed by the utility for approval. In addition, a party may suggest the adoption of a different DSM or EE measure or program as a reason for the Commission to decide not to approve the utility's proposal. A proceeding pursuant to Rule R8-68 is not, however, the proper forum for a party to request that the Commission require the utility to implement a DSM or EE measure or program other than the one proposed by the utility. A party may argue during consideration the utility's IRP plan that it should consider the adoption of additional DSM or EE measures or programs. In addition, a person may initiate a complaint proceeding to request the Commission to require a utility to adopt a specific DSM or EE measure or program. The Commission, therefore, concludes that Rule R8-68 should not be revised to include the language proposed by the Public Staff.

ISSUE 78. Serving copies of filings

Rule R8-68(d)(1) discusses the procedure for serving copies of filings.

Progress contended that serving copies of all filings for DSM and EE program or measure approval on any party requesting service is burdensome and unnecessary because any interested party can easily monitor the Commission's web site for filings of interest. The Public Staff opposed removal of this requirement from Rule R8-68(d). This requirement is essentially taken from Rule R1-38. To reduce the amount of paper used by the utility to meet the service requirement, however, the Public Staff proposed that Rule R8-68(d) provide that the utility may serve parties electronically if possible.

NC WARN, in its comments, noted that the requirement that any interested person can sign up to receive notice and copies of the utility companies' petitions for approval of energy efficiency programs, without the requirement of being an intervenor or even a participant in any Commission proceeding, will assist in promoting energy efficiency measures.

The Commission concludes that it is appropriate to add the Public Staff's language to (d)(1), as follows: "If a party consents, the electric public utility or electric membership corporation may serve it with electronic copies of all filings." The Commission does not, however, believe that the requirement that filings for approval of DSM and EE programs be served on interested parties should be eliminated, since the retention of this requirement will facilitate public involvement in the program review process.

ISSUE 79. Cost recovery for new measures

Rule R8-68(f) discusses the costs that shall be considered for recovery through the annual rider described in Rule R8-69.

Progress proposed that Rule R8-68(f) be revised as follows:

> Except for those costs found by the Commission to be unreasonably and imprudently incurred, the costs of new demand-side management or energy efficiency measures approved by application of this rule shall be recovered through the annual rider described in G.S. 62-133.8 and Rule R8-69.

Duke also requested the inclusion of this same revised language.

The Public Staff asserted that Progress's proposal requires the Commission to approve cost recovery when approving a DSM or EE program. Rule R8-69 provides adequate opportunity for approval of the recovery of costs. Rule R8-68(f) is only intended to allow the Commission to identify, if appropriate, any costs that obviously could not be considered for recovery under Rule R8-69 and G.S. 62-133.8. The Public Staff agreed, however, that the first sentence of this subsection can be clarified as follows:

> Except for those costs found by the Commission to be unreasonable or imprudently incurred, the costs of new demand-side management or energy efficiency measures approved by application of this rule shall be considered for recovery through the annual rider described in G.S. 133.8 and Rule R8-69.

The Commission finds good cause to revise Rule R8-68(f) to include the Public Staff's clarification concerning this issue.

ISSUE 80. Administrative flexibility

ED, SACE and SELC filed comments seeking to expand the flexibility of utilities to pursue cost-effective EE programs without the burden of following a Commission approval process. ED, SACE and SELC suggested that the following language be added to Rules R8-68 and R6-95:

> Administrative Flexibility – Each electric public utility shall describe the amount and type of flexibility that it proposes to have with respect to making incremental modifications to the technologies promoted, customer incentives used, and budget expended within its proposed energy efficiency programs, without explicit Commission authorization being required.

Duke noted that proposed Rule R8-68 adds additional filing requirements to what was already an onerous approval process under Rule R1-38. To foster broad, effective energy EE and DSM programs, Duke argued that the approval process should be nimble and should allow utilities the flexibility to make adjustments to programs throughout the year as needed to optimize results for both customers and the Company. Such flexibility is crucial to the success of the undertaking, particularly in the case of innovative marketing approaches such as that proposed by Duke and in view of the need to make timely and responsive changes as the utility gains experience working with customers in the energy efficiency arena.

According to Duke, Senate Bill 3 requires the Commission to implement rules that encourage investment in EE and DSM. By narrowly defining the options for program recovery, the Commission's proposed rules gut the intent of the statute. The approach for EE and DSM approval and recovery proposed by Duke provides flexibility for utilities to develop, and the Commission to consider, innovative and creative approaches to EE and DSM in order to achieve meaningful results.

While the Public Staff did not seek to impair the flexibility of the utilities to appropriately create and expand energy efficiency programs, it did not agree that Rule R8-68 needs to be amended as described above. Energy efficiency programs comprise a component of REPS compliance and are eligible for comprehensive cost recovery under Senate Bill 3. For those reasons, the Public Staff believes that the Commission ought to maintain the oversight that the proposed Commission rules currently provide. If a utility had a program for which it specifically sought the additional flexibility described above, it could request a deviation from the Commission's rules pursuant to Rule R1-30.[8] The Public Staff maintained, however, that it is more prudent at this time, with so much untested, for the Commission to allow such flexibility in special cases only and not across the board.

Proposed Rule R6-95 is simply intended to be a re-codification of existing Rule R1-38 tailored specifically to natural gas utilities. Senate Bill 3 did not modify existing law with respect to incentive programs for such utilities, and it is not within the scope of this rulemaking proceeding to modify the incentive program rules applicable to natural gas utilities.

The Commission agrees with the Public Staff and concludes that additional rule changes to address this issue are unnecessary.

RULE R8-69

ISSUE 81. DSM/EE rider to include a true-up

The DSM/EE rider is authorized by G.S. 62-133.8(d), which provides that the Commission shall "approve an annual rider to the electric public utility's rates to recover all reasonable and prudent costs incurred for adoption and implementation of new [DSM and EE] measures." The DSM/EE rider proposed in Rule R8-69(b) as set forth in the Commission's October 26, 2007 Order would operate on a historical basis with no true-up.

Duke, Progress and Dominion supported a DSM/EE rider with a true-up. The Public Staff, ED, SACE and SELC initially supported a historical rider with no true-up, but they changed positions in their reply comments to support a true-up rider. The Attorney General and Wal-Mart opposed a DSM/EE true-up.

The arguments made by the parties are similar to the arguments concerning the REPS rider as summarized above. Those who opposed a true-up cited the language in G.S. 62-133.8(d) providing for recovery of "costs incurred" and argued that this phrase means historical costs. They also cited State ex rel. Utilities Comm'n v. Thornburg, 84 N.C. App. 482, rev. denied, 320 N.C. 517 (1987), which they read as requiring specific

[8] Rule R1-30 provides that "the Commission may permit deviation from these rules insofar as it finds compliance therewith to be impossible or impracticable" in special cases.

statutory language before a true-up is permissible. There is no such specific language in G.S. 62-133.8.

Those who supported a true-up argued that true-up opponents are reading too much into the word “incurred” and that the Commission has broad authority to establish provisional rates with true-ups, even without any specific enabling language. They argued that G.S. 62-133.8(d) gives the Commission wide latitude in fashioning cost recovery for DSM and EE, including incentives. Finally, they argued that prospective cost recovery with a true-up will encourage the utilities to comply with the new legislation more enthusiastically.

As discussed above, the Commission has generally approved a provisional or formula rate with a true-up when authorized by statute or in situations involving significant cost items that are uncertain and subject to rapid fluctuation for reasons beyond the utility’s control. There is broad support for a true-up among the parties in this docket. In addition, in the recent Duke general rate case, the Commission relied upon its general ratemaking authority and the “reward” language of G.S. 62-2(a)(3a) to approve an adjustable rider, the Existing DSM Program Rider, which will true-up on an annual basis the costs associated with Duke’s existing DSM programs. <u>Order Approving Stipulation and Deciding Non-Settled Issues</u>, issued December 20, 2007, in Docket No. E-7, Sub 828 et al. The Commission concludes that it will adopt a DSM/EE rider with a true-up. The Commission believes that the costs associated with the programs eligible for collection through the proposed DSM/EE rider will be uncertain in amount and subject to unpredictable fluctuations and that they are, therefore, of the type that may be appropriately recovered using a provisional or formula rate with a true-up. In addition, a DSM/EE rider with a true-up can serve as a “reward,” as authorized by G.S. 62-2(a)(3a). Thus, approval of a DSM/EE rider with a true-up is appropriate as a legally-permissible formula rate of the type allowed pursuant to the Commission’s authority under the general ratemaking provisions of Chapter 62 of the General Statutes and as a “reward” under G.S. 62-2(a)(3a).

Proposed Rule R8-69(b) as set out in the Commission’s October 26, 2007 Order had no true-up; however, the Public Staff proposed a version of Rule R8-69(b) that included a DSM/EE rider with a true-up in its reply comments. The Commission has re-worded some provisions of this Public Staff proposal in the interest of greater consistency with other provisions of Rule R8-69 and with the language of the rules dealing with the REPS and fuel charge adjustment riders. The Commission will consider all evidence that will assist it in setting the DSM/EE rider, including evidence of prospective expenses and projections. The Commission notes that projections and true-ups may need to operate differently when programs involve utility incentives, including net lost revenues, and the Rule therefore allows for whatever ratemaking treatment the Commission finds appropriate as to utility incentives.

ISSUE 82. Reference to net lost revenues in definition of “Annual Rider”

Progress, in its initial comments, proposed that the definition of “Annual Rider” in Rule R8-69(a)(2) should be modified as follows:

> "Annual Rider" means a charge or rate established by the Commission annually pursuant to G.S. 62-133.8(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,~~ net lost revenues and, if appropriate, electric utility incentives.

Progress asserted that the net lost revenues are a cost incurred by the utility and that the utility should be entitled to recover them.

The Public Staff, in its reply comments, noted that Progress requested that net lost revenues be referred to as a utility cost in Rule R8-69. The Public Staff observed that while G.S. 62-133.8 does not define all "recoverable costs", it nevertheless does not expressly refer to "net lost revenues." The Public Staff did not dispute that a utility may recover "net lost revenues." However, the Public Staff believes that an electric utility must demonstrate the appropriateness of "net lost revenue" recovery through the procedure provided for in the proposed rules. Therefore, the Public Staff was opposed to the changes that Progress proposed to Rule R8-69 that seemed to require recovery of net lost revenues without requiring the proposed showing that the Public Staff believed the utility should have to make. The Public Staff suggested one minor edit to Rule R8-69(a)(2). The Public Staff proposed that the word Rider be changed to lower case - "Annual ~~R~~rider".

Consistent with the Commission's prior discussion and conclusions regarding the proper definition of "net lost revenues" in Rule R8-68(b)(5), wherein it concluded that net lost revenues are a type of utility incentive that may be recovered in an annual rider, if appropriate, the Commission rejects Progress's proposed modifications to Rule R8-69(a)(2). However, the Commission concludes that the proposed rule should be modified to clarify that utility incentives may include net lost revenues, so that the text after the date of August 20, 2007, should be changed to "as well as, if appropriate, utility incentives, including net lost revenues." Further, the Commission accepts the Public Staff's proposed change to replace the uppercase 'R' in the word Rider with a lowercase 'r.'

ISSUE 83. Recovery of costs to include net lost revenues

Progress, in its initial comments, proposed that Rule R8-69(b)(1), concerning recovery of costs, should be modified, in part, as follows:

> The ~~costs recoverable in each year's~~ annual rider shall allow an electric public utility to recover its demand side management and energy efficiency ~~consist of the actual expenses~~ costs ~~incurred~~, net lost revenues and any permitted incentive ~~by the electric public utility~~ during an historical 12-month period for adopting and implementing new demand-side management and energy efficiency measures approved pursuant to Rule R8-68, and found by the Commission to be reasonable and prudent.

With respect to its proposed changes in the first sentence, Progress commented that "costs" is a defined term in Rule R8-68 and this sentence appears to redefine it.

Nucor, in its reply comments, stated that the Commission should reject Progress's proposal to modify proposed Rule R8-69(b)(1) to require the Commission to allow utilities to recover net lost revenues. Nucor opined that Progress has revised the rules to make approval of the recovery of net lost revenues mandatory rather than discretionary.

The Public Staff, in its reply comments, stated that it was opposed to Progress's revisions to Rule R8-69(b)(1). The Public Staff pointed out that Progress requested that net lost revenues be referred to as a utility cost. The Public Staff observed that, while G.S. 62-133.8 does not define all "recoverable costs", it nevertheless does not expressly mention "net lost revenues." The Public Staff acknowledged that a utility may recover net lost revenues; on the other hand, the Public Staff maintained that an electric utility must demonstrate the appropriateness of the recovery of net lost revenues through the procedure provided for in the proposed rules. The Public Staff was opposed to the changes that Progress proposed to Rule R8-69 that tend to require recovery of net lost revenues without the proposed showing by the utility.

Consistent with the Commission's prior discussion and conclusions regarding the proper definition of "net lost revenues" in Rule R8-68(b)(5), in which it concluded that net lost revenues are a type of utility incentive that may be recovered in an annual rider, if appropriate, the Commission rejects Progress's proposed modifications relating to net lost revenues.

ISSUE 84. Cost allocation under DSM/EE rider

In its suggested revisions to proposed Rule R8-69(b)(1), Progress proposed, in pertinent part, the following modifications:

> Those ~~expenses~~ <u>costs</u> approved for recovery shall be <u>recovered solely from retail customers and shall be</u> allocated to the North Carolina retail jurisdiction consistent with <u>retail</u> system benefits provided by the new demand-side management and energy efficiency measures and shall be assigned to customer classes <u>based upon the one-hour peak coincident peak methodology</u> in accordance with G.S. 62-133.8(e) and (f). [Endnote omitted.]

In the endnote omitted above, Progress stated that its proposed allocation "methodology most accurately assigns costs based upon cost causation, thus sending the correct price signals to the customer. The jurisdictional allocation contemplated by this section is understood to be retail only, for example – North Carolina retail, South Carolina retail, given that these programs are solely designed for retail customers."

NCFB, in its initial comments, noted that the costs of DSM and EE measures should be assigned only to the class of customers that directly benefit from the programs and, in particular, that agricultural customers should only be responsible for such costs that directly benefit them.

In their reply comments, as noted elsewhere herein, ED, SACE and SELC have indicated that they believe that the Commission should determine appropriate cost allocation methods in connection with its consideration of utility filings for rate riders and that the adoption of a substantive rule governing the allocation methodology would be premature. Furthermore, ED, SACE and SELC commented that they were of the opinion that the coincident peak method may not be appropriate for the recovery of the costs of EE measures and programs which save energy and/or which may contribute to the deferral of the need to construct baseload generation capacity.

In its reply comments, Nucor noted that it supported using a single coincident peak methodology to allocate DSM and energy efficiency costs. However, Nucor proposed that Progress's language be modified to state that DSM and energy efficiency costs under the rider will be allocated based on <u>firm</u> peak demand. Additionally, Nucor argued that DSM and energy efficiency costs should not be allocated to interruptible load.

In its reply comments, the Public Staff stated as follows:

> The Public Staff further opposes [Progress's] proposed revisions regarding cost allocation. The Public Staff believes that DSM and EE measures have a value beyond the one-hour peak, and that the Commission should decide cost allocation as it initially proposed. While [Senate Bill 3] gives the Commission the authority to allocate the costs, it did not prescribe this particular method.

The Commission initially proposed the following language with respect to cost allocation:

> 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. 62-133.8(e) and (f).

As explained elsewhere herein, issues involving cost allocation are complex. Additionally, the manner in which such issues are ultimately resolved has important consequences. The appropriate resolution of cost allocation issues almost always requires evidentiary proceedings. The present issue is no exception to that general rule. Indeed, the Commission is of the opinion that the record in this rulemaking proceeding is plainly inadequate to allow the Commission to make an informed decision.

Therefore, based upon the foregoing logic and the entire record of this proceeding, the Commission finds and concludes that it should not include a requirement in the provisions of this Rule that would mandate the use of a particular cost allocation methodology and/or require that the costs at issue here be recovered solely from retail customers.

ISSUE 85. Implementation date for DSM and EE measures to be eligible for cost recovery under the DSM/EE rider

Section 16 of Senate Bill 3 states: "The provisions of Section 4 apply only to costs that are incurred on and after the date that this act becomes law." Section 4(a) of Senate Bill 3 adds a new Section 62-133.8, entitled "cost recovery for demand-side management and energy efficiency measures," which allows utilities to petition the Commission to recover costs incurred "for adoption and implementation of new demand-side management and new energy efficiency measures." G.S. 62-133.8(a) states, among other things, that:

> As used in this section, "new," used in connection with demand-side management or energy efficiency measure, means a demand-side management or energy efficiency measure that is adopted and implemented on or after 1 January 2007, including subsequent changes and modifications.

Progress proposed to clarify proposed R8-69(b)(3) by stating that any costs related to DSM or EE measures "implemented prior to January 1, 2007, are ineligible for recovery through the annual rider." Under its proposal, costs incurred after that date <u>would</u> be eligible for recovery.

The Public Staff opposed Progress's proposed amendment, pointing out that only costs incurred after August 20, 2007, the date Senate Bill 3 became law, are eligible. In addition, the Public Staff argued that the cost recovery provisions apply only to "new" DSM and EE measures, "which means that the programs were 'adopted and implemented on or after 1 January 2007.'" It stated that "a program or measure that is not truly 'new' is not eligible for cost recovery."

The Public Staff stated that DSM and EE costs incurred after the legislation's effective date (August 20, 2007) are eligible for recovery by means of the rider if they are associated with a new measure or program, <u>i.e.</u>, one adopted and implemented after January 1, 2007.

The Commission agrees with the Public Staff and concludes that Rule R8-69 should not be revised to include Progress's proposed language.

ISSUE 86. Adjust the DSM/EE rider regarding deferral of costs

As proposed, R8-69(b)(4) would allow an electric public utility to:

> 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 begin deferring the costs of adopting and implementing the measure. 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. This return is not subject to compounding. However, deferral accounting of costs shall not affect the Commission's authority under this rule to determine whether the deferred costs may be recovered.

Progress and Duke urged the Commission to adopt a rule that would allow for the deferral of costs that the electric utility believes to be reasonable and prudent prior to Commission approval of the measure or program. The utilities stated that the proposed rule restricts deferral of DSM and EE program costs until the programs are approved by the Commission. They argued that reasonable and prudent costs incurred prior to Commission approval should be eligible for deferral in order to encourage DSM and EE investments. They suggested the inclusion of a provision that would allow electric public utilities to defer costs incurred prior to Commission approval of a measure or program, such as program development costs, and costs incurred related to general DSM and EE activities such as studies, assessments, general promotion, and administration.

The Public Staff asserted that the utilities' proposed language was vague and overly broad and did not agree to it. Nevertheless, the Public Staff was persuaded that a "ramp-up" period prior to seeking Commission approval of a new DSM or EE program may be necessary to promote the utilities' adoption and implementation of such programs. For this reason, the Public Staff proposed that an electric public utility be allowed to begin deferring costs associated with adopting and implementing new DSM or EE measures six months prior to the filing of its application for approval. The Public Staff's proposal would specifically exclude administrative costs, general costs, or other costs not directly related to the new DSM or EE measure. According to the Public Staff's reply comments, Progress opposes the six-month period for the deferral of "ramp up" costs, preferring instead an indeterminate time period for deferral.

In its initial comments, the Public Staff proposed to clarify proposed R8-69(b)(4) regarding recovery of income taxes, as follows:

> 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. <u>The return so calculated will be adjusted in any rider calculation to reflect necessary recoveries of income taxes.</u> This return is not subject to compounding.

The Commission concludes that the Public Staff's proposal to allow electric public utilities to use deferral accounting for certain expenses incurred six months prior to filing a related program application is reasonable. The Commission agrees with the Public Staff, Progress and Duke that utilities will need to expend resources in order to develop effective DSM and EE programs before they seek Commission approval of those programs. In order to encourage utilities to develop effective DSM and EE programs, the Commission will allow them to defer certain costs (as described by the Public Staff) incurred six months prior to seeking program approval. However, the Commission believes it is possible that a robust efficiency program will require development costs over a period of time longer than six months. Therefore, while the Commission generally believes that six months prior to a request for program approval is an appropriate program development cost deferral period, the Commission will consider longer deferral periods in extraordinary cases. The Commission concludes that such flexibility is necessary in order to facilitate the development of robust and effective energy efficiency initiatives.

To encourage electric public utilities to pursue energy efficiency resources, the Commission concludes that it is appropriate to allow them to earn a return on the deferral balance, as originally proposed by the Commission. Similarly, the Commission concludes that it is appropriate to clarify that a return accrued at a net-of-tax rate on a deferral account will be adjusted in the rider calculation to reflect the necessary recovery of income taxes, as proposed by the Public Staff in its initial comments.

ISSUE 87. Net lost revenues provisions in Rule R8-69(c)

Progress, in its initial comments, stated that net lost revenues are costs that the utility should be entitled to recover.Therefore, Progress urged that proposed Rules R8-69(c)(1) and (2), which provide as follows, be stricken:

> (c) Net Lost Revenues.
>
> (1) In the annual rider proceeding, an electric public utility may apply for recovery of net lost revenues related to new demand-side management or energy efficiency measures previously approved under Rule R8-68. The burden of proof as to the amount of net lost revenues and the reasonableness and prudence of their inclusion in the rider shall be on the electric public utility.
>
> (2) An electric public utility shall not be permitted to implement deferral accounting or accrual of a return on net lost revenues unless the Commission approves an annual rider that provides for recovery of an integrated amount of recoverable costs and net lost revenues. In that instance, the Commission shall determine the extent to which deferral accounting and the accrual of a return will be allowed.

Nucor, in its reply comments, asserted that the Commission should retain proposed Rules R8-69(c)(1) and (2), which address the recovery of net lost revenues by electric power suppliers. Nucor observed that, under the Commission's proposed Rule R8-69(c)(1), a public utility may apply for recovery of net lost revenues related to new DSM or EE measures in an annual rider proceeding, and the utility bears the burden of proof as to the amount of net lost revenues and the reasonableness and prudence of inclusion of such amounts in the rider. In regard to the Commission's proposed Rule R8-69(c)(2), Nucor stated that that subsection further provides that an electric public utility shall not be permitted to earn a return on net lost revenues unless the Commission approves an annual rider that provides for recovery of an integrated amount of recoverable costs and net lost revenues. Nucor opined that recovery of a return on net lost revenues would be mandatory under Progress's proposed changes, rather than discretionary, as is the case under proposed Rule R8-69(c). Nucor requested that the Commission reject Progress's proposed changes.

Nucor further asserted that the Commission should consider how net lost revenues ought to be treated on a case-by-case basis to ensure that both utilities and their customers are treated fairly. Nucor observed that, unlike Progress's proposed revisions, the Commission's proposed Rule R8-69(c), as currently drafted, provides for a balanced approach to the recovery of net lost revenues by allowing utilities to request cost recovery for such amounts, including a return on net lost revenues, but leaving it up to the Commission to decide whether to allow recovery of net lost revenues through the utility's DSM and EE rider and how such recovery should occur.

As discussed previously, the Attorney General, in his reply comments, recommended that the proposed rules allow for the recovery of net lost revenues as an incentive, but not as a cost. The Attorney General suggested that certain rules should be clarified to characterize net lost revenues as a type of incentive that may be recovered pursuant to G.S. 62-133.8(d)(2), assuming that recovery is found to be appropriate. The Attorney General stated that the utility should have the burden of proof as to the amount of net lost revenue recovery and the extent to which including net lost revenues in the rider is reasonable, prudent, and in the public interest. Therefore, the Attorney General suggested that proposed Rule R8-69(c)(1) be modified as follows:

> In the annual rider proceeding, an electric public utility may apply for recovery of net lost revenues related to new demand-side management or energy efficiency measures previously approved under Rule R8-68 to the extent net lost revenues were identified as an incentive in its application for approval of the measure. The burden of proof as to the appropriateness of allowing recovery of net lost revenues, the amount of net lost revenues, and the reasonableness and prudence of their inclusion in the rider shall be on the electric public utility.

As previously indicated, the Public Staff, in its reply comments, noted that Progress requested that net lost revenues be referred to as a utility cost in Rule R8-69. The Public Staff observed that, while G.S. 62-133.8 does not define all "recoverable costs", it nevertheless does not expressly include "net lost revenues." The Public Staff does not dispute that a utility may recover net lost revenues through the rider mechanism, but it does believe that an electric utility must demonstrate the appropriateness of their recovery through the procedure provided for in the proposed rules. Therefore, the Public Staff was opposed to Progress's proposed elimination of Rules R8-69(c)(1) and (2).

Consistent with the Commission's prior discussion and conclusions regarding the proper definition of "net lost revenues" in Rule R8-68(b)(5), wherein it concluded that net lost revenues are a type of utility incentive that may be recovered in an annual rider, if appropriate, the Commission concludes that proposed Rules R8-69(c)(1) and (2) should be deleted and that the first sentence of proposed Rule R8-69(d)(1), concerning utility incentives, should be modified to include the following underlined text:

> 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 <u>utility</u> incentive<u>s, including, if appropriate, net lost revenues,</u> identified in its application for approval of the measure.

ISSUE 88. Recovery of net lost revenues on an aggregate basis

ED, SACE and SELC, in their initial comments, noted that proposed R8-69(c) addresses the net lost revenues issue only by providing a framework for a specific net lost revenues adjustment mechanism that could be incorporated into the rate rider. ED, SACE and SELC stated that, if the Commission decides to issue the rule incorporating this approach, then they would offer the following specific comments. ED, SACE and SELC observed that proposed Rule R8-69(c) and the related parts of Rule R8-69(g) describe what they believe to be necessary requirements for documentation concerning net lost revenues, should a utility seek to identify and recover them.

ED, SACE and SELC stated that, as identified in subsection (b)(5) of Rule R8-68, net lost revenues calculations must take account of any revenue increases flowing from utility activities that increase electricity consumption (and thus revenues). According to ED, SACE and SELC, this is an appropriate offset. ED, SACE and SELC maintained that there is another offset which, although already implicit in the concept of net lost revenues, might be made explicit. ED, SACE and SELC contended that a new EE or DSM program may, in whole or in part, decrease consumption during time periods when the utility's operating costs are higher than its revenue based on current retail rates. ED, SACE and SELC believe that to the extent this occurs, it increases net revenues. ED, SACE and SELC asserted that Rule R8-69, as currently drafted, does not preclude a utility from seeking net lost revenues recovery for some measures, while excluding other measures that provide net gained revenues from the proposed rate adjustment mechanism. In order to preclude such proposals, ED, SACE and SELC suggested that the following provision be added to R8-69(c):

> (3) If an electric utility applies for net lost revenue recovery for EE or DSM programs, it must apply for such recovery on an aggregate basis including all EE and DSM programs.

No other party commented on this issue.

As provided for in proposed Rule R8-69(d)(2), when requesting inclusion of a utility incentive in the annual rider, the electric public utility bears the burden of proving that its calculations of those incentives and justifying their inclusion in the annual rider. Consequently, the Commission concludes that it is unnecessary to include the additional subsection (3) proposed by ED, SACE and SELC.

ISSUE 89. Measurement and verification of net lost revenues

ED, SACE and SELC, in their initial comments, stated that there is also an argument for fully independent measurement and verification (M&V) for any net lost revenue mechanism. ED, SACE and SELC observed that it is difficult to identify the net effect of EE on utility sales because judgment is needed to estimate what energy efficiency gains might have been made in the absence of the utility's efforts and to subtract such "naturally occurring" efficiency from the results attributed to the utility's efforts. ED, SACE and SELC suggested that the same independent M&V that was suggested for instances where the utility seeks incentives for itself may also be appropriate when net lost revenues are sought. ED, SACE and SELC suggested that this path would tend to make net lost revenue recovery proceedings less contentious than they might possibly become. ED, SACE and SELC suggested that the following provision be added to R8-69(c):

> (4) If the electric public utility proposes recovery of net lost revenues, its measurement and verification plan must include provision for the Public Staff to procure independent third party measurement and verification services to demonstrate the net revenue impacts, at the expense of the electric public utility, in lieu of or in addition to measurement and verification the utility proposes to conduct itself.

The Attorney General, in his reply comments, stated that it is appropriate to involve an independent third party to review measurements of the savings achieved by efficiency programs, particularly where incentives are sought, given the potential cost to customers of such programs and the utility's interest in the amount of savings determined to have been achieved. However, the Attorney General did not comment on ED, SACE and SELC's proposed addition.

The Public Staff, in its reply comments, observed that ED, SACE and SELC have suggested that an independent expert would be helpful for purposes of measuring and verifying the utilities' claimed net lost revenues. For the reasons discussed elsewhere regarding the use of independent third-party services in Rule R8-68(c)(3)(vi), the Public Staff agreed that such assistance should be retained, if necessary. However, the Public Staff stated that it did not believe that the rules should expressly provide for the retention of such assistance. Instead, the Public Staff recommended that the retention and scope of an expert's assistance should be determined on a case-by-case basis.

Consistent with the Commission's prior discussion and conclusions concerning the similar proposal advanced by ED, SACE and SELC concerning Rule R8-68(c)(3)(vi), the Commission concludes that it is unnecessary to include the additional subsection (4) proposed by ED, SACE and SELC. The Commission believes it is best to address this matter on a case-by-case basis. Furthermore, the Public Staff already has authority under G.S. 62-15(h) to hire expert assistance and have the affected utility pay the costs. The Commission, therefore, rejects ED, SACE and SELC's proposed addition.

ISSUE 90. Deferral accounting for incentives

As proposed, Rule R8-69(d)(4) states:

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

Progress proposed to eliminate the entire provision, but provided no explanation for its position.

The Commission finds good cause to retain proposed Rule R8-69(d)(4) to prevent deferral accounting or the accrual of a return for incentives unless specifically approved by the Commission.

ISSUE 91. Margin decoupling to encourage utility EE programs

ED, SACE and SELC recognized that EE programs can depress utility revenues and earnings. They stated that, under the net revenue cap approach, a utility's rates are adjusted periodically to account for changing conditions over time. In this way, a utility's net revenues are "decoupled" from its sales levels, so there will be no lost (or gained) revenues from EE or DSM. They suggested that revenue decoupling mechanisms are relatively simple and straightforward.

ED, SACE and SELC recognized that the Commission has already said that it will address decoupling in another proceeding. However, they suggested that the proposed rules acknowledge the utilities' option to put decoupling proposals before the Commission through the inclusion of a paragraph such as the following in Rule R8-69(c):

> (5) As an alternative to proposing to calculate net lost revenues as described in R8-69(c)(1) - R8-69(c)(4), an electric utility that is proposing new EE or DSM for approval may also petition the Commission to convene a proceeding to consider a proposal for general rate decoupling.

Piedmont agreed with ED, SACE and SELC that decoupling is a beneficial and neutral mechanism that has the effect of removing a disincentive to utility participation in programs designed to reduce usage of the utility's product. Piedmont did not agree with ED, SACE and SELC that a decoupling mechanism obviates the need for cost recovery of utility sponsored efficiency programs. Since those costs accrue to the sole benefit of customers and are, at least with respect to new or expanded programs, incremental in nature to the costs built into utility rates which are protected by a decoupling mechanism, an additional cost recovery mechanism is necessary.

The Public Staff stated that the Commission will issue a separate order concerning section 4(c) of Senate Bill 3, which encompasses decoupling. Therefore, the Public Staff opposed the addition of any decoupling provision to the rules at this time as premature.

The Commission agrees with the Public Staff and concludes that Rule R8-69 should not be revised to include the language proposed by ED, SACE and SELC.

ISSUE 92. Conformity of DSM/EE riders with Rule R8-55 and fuel charge adjustment proceeding

As with Rule R8-55 and the fuel charge adjustment, the utilities proposed changes to the DSM/EE rider provisions of Rule R8-69 with regard to (1) interest on under-collections, (2) procedural dates for the utilities and other parties, and (3) the period during which the EMF rider may be updated.

The Commission finds good cause to continue, to the extent practicable, to employ the same procedures with regard to the DSM/EE rider as with the fuel charge adjustment rider. Therefore, for the same reasons stated with regard to the fuel charge adjustment rider, the Commission finds good cause to (1) deny the utilities' proposal to recover interest on under-collections, (2) require utility and intervenor filings on the same schedule as required under Rule R8-55, and (3) allow the utilities to incorporate experienced over- or under-recoveries "up to thirty (30) days prior to the date of the hearing."

ISSUE 93. Subsection heading for Rule R8-69(d)

As discussed previously regarding Rule R8-68, the Attorney General, in his reply comments, recommended that the proposed rules should allow for the recovery of net lost revenues as an incentive, but not as a cost. The Attorney General suggested that certain rules should be clarified to characterize net lost revenues as a type of incentive that may be recovered pursuant to G.S. 62-133.8(d)(2), assuming that recovery is found to be appropriate. The Attorney General stated that the utilities should have the burden of proof with respect to the amount of net lost revenues associated with a particular program and with respect to the issue of whether including net lost revenues in the rider was reasonable, prudent and in the public interest. Therefore, the Attorney General suggested that the heading in Rule R8-69(d) be modified to read: "<u>Other</u> Utility Incentives."

The Public Staff, in its reply comments, proposed that the heading be modified to read: "<u>Electric</u> Utility Incentives."

Consistent with the Commission's prior discussion and conclusions regarding proposed Rule R8-69(c), which the Commission has eliminated, and the Commission's inclusion of additional language in Rule R8-69(d)(1) recognizing that the electric public utility may, in its annual filing, apply for recovery of utility incentives, including net lost revenues, the Commission rejects both the Attorney General's and the Public Staff's proposals to change the heading description of Rule R8-69(d) to "Other Utility Incentives" or to "Electric Utility Incentives", respectively. Thus, the Commission finds that the heading for Rule R8-69(d) should simply be "Utility Incentives."

ISSUE 94. Prospective recovery of incentives in the DSM/EE rider

Proposed R8-69(d)(2) provides:

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

In originally proposing this provision, the Public Staff stated:

> Finally, the Public Staff's proposal incorporates a process by which the utilities may recover the incentives provided for in G.S. 62-133.8(d)(2)a.-c., but the Public Staff believes that the Commission may reward an electric utility only after it has made a clear showing that the new demand-side management or energy efficiency measure has actually achieved a quantifiable result.

Duke commented that, although the language on its face does not appear to prohibit the payment of incentives based upon projections of kilowatt and kilowatt-hour savings with a true-up based upon the results of a measurement and verification plan, the Public Staff suggested that this language would prohibit such a mechanism. Duke asserted that, if the Public Staff's interpretation of this language is adopted, the Rule would discourage utilities from developing EE and DSM models premised upon results-based incentives. The traditional methods of cost recovery promoted by the proposed rules simply do not suffice to encourage major advancements in energy efficiency and will continue to produce the same ineffective results obtained using such methods in the past – especially if they require utilities to wait for prolonged periods to receive the incentives promised by Senate Bill 3.

Duke argued that, under its proposed Save-a-Watt model, it is not seeking recovery for program costs or lost revenues, but rather is proposing to price EE and DSM at 90% of the cost of the generation avoided by efficiency savings. Duke is proposing to only get paid for the results produced, rather than the dollars spent. Under the Public Staff's interpretation, while Duke would spend money to implement programs, it would not receive any compensation for its EE investments until results are measured and verified, which may not occur until 12-36 months after the investments are made. Duke supported measuring and verifying results and has proposed third-party verification of results so that the annual rider can be trued up. The utility must have timely compensation to make the necessary investments. By delaying compensation, the Commission would create a disincentive for EE investments and preclude certain types of recovery models from being proposed.

As stated previously, the rules implementing Section 4 of Senate Bill 3 are not intended to limit recovery for DSM and EE costs for which cost recovery is permitted under the statute. The statute gives the Commission a great deal of latitude in the range of incentives it can approve and in determining the timing of any recovery. However, the Commission does not believe that the language proposed in subsection (d)(2) would preclude Duke from arguing in favor of the prospective recovery of incentives described in G.S. 62-133.8(d)(2) or a party with a contrary view from arguing a different position.

In proposing revisions to Rule R8-69 to incorporate a DSM/EE rider with a true-up, the Public Staff proposed to only allow an electric public utility to apply for recovery of net lost revenues or utility incentives "through the DSM/EE EMF" rider. To clarify that Rule R8-69 is not intended to preclude prospective recovery of utility incentives, including net lost revenues, the Commission concludes that Rule R8-69 should not be revised to include the language proposed by the Public Staff. Lastly, the Commission concludes that proposed Rule R8-69(d)(1) should be revised to include language indicating that the Commission shall determine the appropriate ratemaking treatment for recovery of utility incentives, including net lost revenues. The burden will be on the utility to propose a workable and legally permissible true-up methodology in its DSM/EE rider request.

ISSUE 95. Presumption against incentives for DSM/EE measures that pass ratepayer impact measure (RIM) test

Proposed Rule R8-69(d)(3) is worded as follows:

> A demand-side management or energy efficiency measure that passes the Ratepayer Impact Measure cost-effectiveness test is presumed not to require the inclusion of incentives associated with that measure in the annual rider.

Dominion, in its initial comments, urged the Commission to delete proposed Rule R8-69(d)(3). Dominion asserted that this provision appears inconsistent with Senate Bill 3 and could have unintended consequences because certain incentives may no longer be available for what may be an effective program.

Likewise, Progress, in its initial comments, requested that proposed Rule R8-69(d)(3) be deleted. Progress asserted that such proposed rule is inconsistent with the intent of Senate Bill 3; creates a disincentive for utilities to propose cost-effective DSM and EE programs; and creates a perverse incentive for utilities to earn incentives for DSM and EE programs that raise rates for consumers, but denies utility incentives for programs that cause rates to be lower than they would otherwise be.

Similarly, Duke urged the Commission to delete proposed Rule R8-69(d)(3). In its initial comments, Duke remarked that neither the Public Staff nor the Commission provided any explanation for the creation of an irrebuttable presumption that programs that pass the RIM test cannot qualify for incentives.[9] Duke also observed that the proposed rule does not define what constitutes passing the RIM test. Duke opined that, although a positive RIM test result may indicate that a program will result in cost savings, it does not show the period over which such savings will be experienced. Duke stated that, invariably, such cost savings occur over time while the Company incurs costs upfront in connection with the implementation of the program. Duke explained that customers enjoy the benefits, through future rates, of the cost avoidance resulting from a program that passes the RIM test. On the other hand, according to Duke, the shareholders are harmed financially if the program reduces future earnings below the level of earnings that would otherwise result from building new generation. Therefore, Duke maintained that, under such circumstances, incentives are necessary to encourage the utility to invest in such a program. Accordingly, Duke asserted that proposed Rule R8-69(d)(3) provides a disincentive to the implementation of programs that provide rate benefits for all customers. Thus, Duke argued that there is no rational basis for providing incentives for programs that increase costs to customers while penalizing the utility for developing and implementing programs that reduce costs for all customers.

Further, Duke argued that this proposed rule appears to be in conflict with the provisions of Senate Bill 3. In particular, Duke noted that G.S. 62-133.8(c) requires the electric utility to "submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval." Duke maintained that this statutory language contemplates a case-by-case consideration of the need for incentives, whereas proposed Rule R8-69(d)(3) forecloses such consideration if the program passes the RIM test. In addition, Duke argued that, because there is no rational connection between passing the RIM test and the need for or appropriateness of incentives, creating an irrebuttable presumption by rule, especially without an evidentiary record, raises serious due process concerns under both the federal and North Carolina constitutions.

Moreover, Duke commented that it has proposed an innovative regulatory approach to EE and DSM in Docket No. E-7, Sub 831 (Save-a-Watt Docket) that is premised not on the recovery of costs and lost revenues, but on the payment of a utility incentive in the form of a percentage of the avoided cost of new generation. Duke noted that the Commission has yet to address the merits of its proposal. Duke asserted that, if the Commission implements recovery rules that prohibit the recovery of incentives for certain EE and DSM programs, the Commission will have prejudged the merits of Duke's proposal without the benefit of an evidentiary hearing and will have effectively

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[9] Duke supported the Commission's prior conclusions that no single cost evaluation test is determinative in evaluating whether an EE or DSM program is cost-effective. Duke represented that it supports the industry best practice, which involves the use of a combination of cost-effectiveness tests, including the Utility Cost Test (UCT), the Total Resource Cost Test (TRC), and the RIM Test for screening EE measures. In addition, Duke stated that the Participant Test is used to ensure that a particular a program makes economic sense for the individual consumer. Duke believes that the results from all of these tests should be reviewed and considered in deciding whether a program should be implemented.

foreclosed the opportunity for a fair consideration of this approach. If that is the Commission's intent in this docket, Duke requests the opportunity to be heard through an oral argument and to present testimony in support of its proposal. Duke opined that such action would contradict both the spirit and letter of Senate Bill 3.

In their initial comments, ED, SACE and SELC observed that, in the proposed subsections of Rule R8-69(d), Utility Incentives, the Commission leaves open the issue of an appropriate incentive structure; the utilities are provided the opportunity to submit incentive proposals of their own design in conjunction with filings for new EE or DSM measures. ED, SACE and SELC also remarked that proposed Rule R8-69(d)(3), which states that measures that pass the RIM test are presumed not to require utility incentives, is a needed and important provision.

The Public Staff, in its initial comments, suggested that Rule R8-69(d)(3), stating that a DSM or EE measure that passes the RIM test is presumed not to require incentives associated with that measure or program, should be removed. However, the Public Staff explained that, while it believes that such a presumption would generally be true, it nevertheless believes that the Commission should determine utility incentives on a case-by-case basis rather than adopt a substantive rule of universal applicability. Consequently, the Public Staff recommended that proposed Rule R8-69(d)(3) should be eliminated.

In their reply comments, ED, SACE and SELC acknowledged that the Public Staff proposed in its initial comments that Rule R8-69(d)(3), which provides that DSM or EE measures that pass the RIM test are presumed not to require incentives, should be eliminated. ED, SACE and SELC pointed out that the Public Staff, like ED, SACE and SELC, believes it is generally true that incentives are not appropriate for such measures, but the Public Staff has suggested that the matter be addressed in the context of Commission consideration of specific utility filings and not in the rules.

ED, SACE and SELC remarked that many DSM measures and programs will pass the RIM test, while many EE measures will not. They explained that EE measures require distinctive and innovative marketing activities by utilities and that such measures have the potential to erode utility profits in a way that DSM measures do not. Further, ED, SACE and SELC stated that consideration of incentives for EE measures is appropriate; however, DSM measures are already being offered by utilities and incentives are generally not appropriate for such programs. ED, SACE and SELC observed that, since EE measures will often fail the RIM test while DSM measures will generally pass, the RIM test language that the Public Staff would now drop appropriately recognizes the significant differences between EE and DSM in terms of their impacts on and their challenges to utilities. ED, SACE and SELC suggested that the RIM test language in the rules as currently proposed be retained, noting that it establishes a reasonable presumption but not an irrebuttable one.

The Public Staff offered no additional comments on this issue in its reply comments. The Public Staff did include an Appendix A, attached thereto, which incorporated all the changes proposed by other parties that the Public Staff supported, and it removed certain changes originally proposed by the Public Staff to which other parties persuasively objected. In Appendix A, the Public Staff maintained its position that proposed Rule R8-69(d)(3) should be removed.

In the jointly filed reply comments of Duke, Dominion and Progress, the utilities stated that they agreed with the Public Staff's recommendation to remove the provision in proposed Rule R8-69(d)(3) that would preclude incentives for EE and DSM programs that pass the RIM test.

The Commission believes that if Rule R8-69(d)(3) is adopted, as proposed, it could discourage the implementation of some beneficial EE and DSM programs and that such a result would be contrary to the intent behind Senate Bill 3. Pursuant to G.S. 62-133.8(b), the utilities are required to use DSM and EE measures and supply-side resources to establish the least-cost mix of demand reduction and generation measures. According to G.S. 62-133.8(d), the utilities are allowed incentives for implementing such measures. Consequently, the Commission agrees with Duke that passing the RIM test should not necessarily preclude a utility from obtaining incentives. Accordingly, the Commission concludes that it would be inappropriate to adopt Rule R8-69(d)(3), which would effectively foreclose the consideration of utility incentives for programs that pass the RIM test. Therefore, proposed Rule R8-69(d)(3) should not be adopted.

In addition, as stated previously, Duke has asserted that if the Commission implements recovery rules that prohibit the recovery of incentives for certain EE and DSM programs, the Commission will have prejudged the merits of Duke's Save-a-Watt proposal without the benefit of an evidentiary hearing and will have effectively foreclosed the opportunity for a fair consideration of its proposed approach. By Order issued August 31, 2007, in Docket Nos. E-7, Subs 828, 829 and 831, and Docket No. E-100, Sub 112, the Commission stated that it

> will hear and decide the merits of Duke's Save-a-Watt application after completion of the Senate Bill 3 rulemaking which is presently underway in Docket No. E-100, Sub 113 …. The Chairman will, by further Order, schedule the Save-a-Watt Plan for hearing at an appropriate time in 2008.

The Commission has not and would not prejudge Duke's Save-a-Watt proposal in this proceeding to adopt rules implementing Senate Bill 3.

ISSUE 96. Threshold required for commercial customer opt-out

G.S. 62-133.8(f) allows industrial customers and "commercial customers with significant annual usage at a threshold level to be established by the Commission" to opt out of electric power supplier's new DSM and EE measures. Proposed Rule R8-69(a)(4) defines "large commercial customer" as any commercial customer that has an annual energy usage of not less than 1,000,000 kWh.

The electric power suppliers argued that the proposed energy usage standard adopted in subsection (a)(4) is much too low. Duke, Progress, Dominion and NCEMC suggested that annual energy usage of 3,000,000 kWh is more appropriate, while ElectriCities maintained that "significant" usage should be in excess of 5,000,000 kWh per year. The electric suppliers argued that the lower the threshold, the larger the number of customers that can out opt and the greater the burden placed on the remaining body of customers.

ED, SACE and SELC argued that, to facilitate the development of EE programs which may yield the highest feasible level of electricity savings for North Carolina, the Commission should set a very high, but unspecified, threshold usage level.

Wal-Mart, on the other hand, believed that the proposed threshold of 1,000,000 kWh is appropriate and should not be changed. In the alternative, however, Wal-Mart asserted that the Commission should allow large commercial users to aggregate their statewide usage if the Commission is convinced that the threshold should be raised from the current proposal.

The Public Staff stated that, while it shares the concerns expressed by the electric power suppliers that the level proposed is too low, it would not recommend amending the proposed energy usage standards.

After fully reviewing the contentions of the parties, the Commission is not persuaded that a higher threshold should be adopted and will maintain the annual usage threshold at which a large commercial customer can opt out of utility-sponsored DSM or EE programs at 1,000,000 kWh. Pursuant to G.S. 62-133.8(f), a large commercial customer may only opt out if the customer notifies its electric power supplier that the customer, at its own expense, has implemented at any time in the past or will implement alternative DSM and EE measures in accordance with stated, quantified goals.

ISSUE 97. Showing required for customer opt-out

Senate Bill 3 provides that certain customers may opt out of their utility's new DSM or EE programs when, at their own expense, they have implemented their own DSM or EE measures or will implement their own DSM or EE programs in accordance with stated, quantified goals. Rule R8-69(e)(1), which provides, in part, as follows, does not impose any requirements that a customer must satisfy in order to opt out of new utility-sponsored DSM or EE programs:

> Pursuant to G.S. 62-133.8(f), any industrial customer or a large industrial customer may notify its electric power supplier that it has implemented or, in accordance with stated, quantifiable goals, will implement alternative demand-side management or energy efficiency measures.

In its initial and reply comments, Duke argued that any customer choosing to opt out must be able to demonstrate to its electric power supplier that the alternative EE and DSM measures it has implemented or has definitive plans to implement at its own expense are substantially equivalent to those offered by the electric power supplier. Otherwise, according to Duke, such customers will be able to avoid paying their share of deferred generation costs without having made a comparable investment to that made by participating customers.

ED, SACE and SELC supported the concept embodied in Duke's proposal. They further proposed that any customer electing to opt out be required to provide detailed descriptions of measures evaluated and measures implemented or planned, together with quantified results and projections.

Wal-Mart, Nucor, CUCA and CIGFUR opposed Duke's proposal. CIGFUR and CUCA further argued that ED, SACE and SELC's proposed detailed description requirement goes beyond the letter and intent of the statute, G.S. 62-133.8(f), which only requires notice to the supplier that programs have or will be implemented and that the customer elects to opt out. Further, the General Assembly adopted a complaint procedure as the method for challenging the validity of opt-out notices, and the proposal runs the risk of requiring the disclosure of company proprietary data.

In its supplemental filing, Progress stated that it agreed with CUCA and CIGFUR that Senate Bill 3 grants to industrial customers the right to opt out of all DSM and/or energy efficiency programs offered by their electric power supplier provided such industrial customers implement alternate DSM and/or energy efficiency programs on their own. Senate Bill 3 does not include a requirement that such alternate DSM and/or energy efficiency programs be equivalent to those offered by the electric supplier.

The Commission concludes that Rule R8-69 should not be revised to include either Duke's proposal to require a "substantially equivalent" test in order for customers to opt out of DSM and EE programs or ED, SACE and SELC's proposal that customers desiring to opt out be required to provide detailed descriptions of measures evaluated and measures implemented or planned together with quantified results and projections of the impact of the measures. Senate Bill 3, in general, and G.S. 62-133.8(f), in particular, do not contain any requirement that DSM or EE programs implemented by the customer or DSM or EE programs proposed to be implemented by the customer must be substantially equivalent to the programs or measures being supplied by the electric power supplier. Nor does Senate Bill 3 require customers desiring to opt out to provide detailed descriptions of measures evaluated and measures implemented or planned together with quantified results and projections of the impact of the measures. All that is required of a program used as the basis for a customer's decision to opt out is that: (1) the program have been implemented in the past or (2) that it be proposed to be implemented in the future in accordance with stated, quantified goals.

ISSUE 98. Ability of customer that opts out to opt back in

Proposed Rule R8-69(e)(3) provides as follows:

> (3) Any customer that opts out but subsequently elects to participate in a new demand-side management or energy efficiency measure loses the right to be exempt from payment of the rider for the life of the measure. Within 30 days of the customer's election, the electric public utility shall notify the Commission of an industrial or large commercial customer that elects to participate in a new measure after having initially notified the electric public utility that it declined to participate.

In its initial and reply comments, Nucor commented that the proposed Rule R8-69(e)(3) creates a disincentive for industrial and large commercial customers to develop alternative DSM and EE measures because it locks an industrial or large commercial customer into the electric power supplier's DSM and EE programs once it elects to participate in such programs. To remove this disincentive, Nucor proposed that Rule R8-69(e)(3) should be amended to allow an industrial or large commercial customer to opt back into, i.e., participate in such programs, after it has previously elected to opt out of participation provided that the customer would lose "the right to be exempt from payment of the rider unless and until the customer notifies its electric power supplier that it has implemented or will implement alternative demand-side management and energy efficiency measures in accordance with G.S. 62-133.8(f)." Nucor's proposal would thus allow a customer to unilaterally opt into and opt out of utility-sponsored programs provided the customer gives notice to the utility without any regard to the effect of such decision on the utility and its remaining customers.

ElectriCities' comments opposed allowing large commercial and industrial customers to opt out and opt back into utility-sponsored DSM and EE programs and, instead, proposed that an industrial customer that opts out of new DSM or EE measures forfeit the right to participate in any such measures thereafter. ElectriCities argued that municipalities need to know for planning purposes which industrial customers will participate in DSM and EE measures. For that reason, ElectriCities also recommended that the Commission add a January 1, 2010, date certain requirement for an industrial customer or large commercial customer to notify the electric power supplier that it is opting out.

Senate Bill 3, as enacted, only specifies that industrial and some commercial customers may opt out of participating in new DSM or EE programs. It does not specifically address Nucor's proposed "opt in/opt out again" language, which would allow multiple opt-in/opt-outs by customers. Despite the lack of specificity, the Public Staff asserted that a customer should be allowed to participate in any new DSM or EE program even if it has previously opted out of such measures. In the Public Staff's opinion, if a customer chooses to opt back into, or chooses to participate in, a new DSM or EE program or measure that it finds beneficial, it should not only receive the benefit of the program or measure, it should also bear the cost. In that situation, where the customer chooses to opt back into a new DSM or EE program or measure, the Public

Staff argued that the customer should then have the cost of the new DSM and EE measures or programs under G.S. 62-133.8 assigned to it <u>and</u> should be required to participate in the rider for the remaining life of the measure or program that it has opted into.

The Commission agrees with the recommendation that allows industrial and large commercial customers that have opted out of utility-sponsored DSM and EE programs to subsequently opt back into such programs as a matter of fairness and equity. In the Commission's opinion, the proposal would accomplish the statutory mandate of allowing industrial and large commercial customers to opt out of financial responsibility for new DSM or EE programs if they choose to implement alternative programs at their own expense. At the same time, the customer's decision to opt out should not preclude an industrial or large commercial customer from, at a later date, taking advantage of an electric power supplier's new DSM or EE programs which may be beneficial to the customer. In instances in which a customer chooses to opt back into the electric power supplier's measure or program, it should receive not only the <u>benefit</u> of the program or measure for the life of the program or measure but also the financial responsibility for the DSM/EE rider for the life of the measure or program. Allowing this limited "opt-out/opt-in" option would appear to be fair and beneficial both to the electric power supplier and the customer.

By adopting this recommendation, the Commission rejects Nucor's proposal that customer that chooses to opt back into a program or measure to assume financial responsibility for its decision only until the customer "notifies its electric power supplier that it has implemented or will implement alternative demand-side management and energy efficiency measures in accordance with G.S. 62-133.8(f)." If the Nucor recommendation were adopted, it would undercut the electric power suppliers' ability to advance DSM and EE measures or programs by allowing industrial or large commercial customers to self-direct the costs and benefits of DSM and EE programs. Electric power suppliers would thus be deprived of the ability to control the administration, cost and electric distribution system effects of the programs they implement. In addition, allowing such customers to self-direct the costs and benefits and to opt into and out of electric supplier DSM and EE programs on a short-term basis would unfairly dilute participation in such programs and shift the cost burden of such programs to the electric power suppliers and other retail customers.

The Commission firmly believes that electric power suppliers should be able to plan EE and DSM programs with some degree of certainty about the identity of the participants in those programs or measures. Requiring industrials or large commercial customers to opt out of such programs by a date certain as suggested by ElectriCities would be beneficial. Although the requirement of a date certain for opting out would be beneficial for electric power suppliers' planning purposes, imposing such a requirement on an industrial or large commercial customer is inconsistent with the permissive language allowing customers to "opt out" that appears in G.S. 62-133.8(f). Thus, rather than include a date certain in the rules, the better alternative would be for the electric power suppliers and their industrial and large commercial customers to work out notification provisions among themselves as recommended by the Public Staff.

In its comments, CUCA requested a clearer definition of the "life of the measure" and questioned whether "life of the measure" meant that an industrial or commercial customer could opt into the rider for the life of a 20-year measure or program or for only five years of the life of a specific piece of equipment associated with the measure or program. Similarly, CIGFUR requested that "remaining" be inserted before "life" to clarify the meaning of the "life of the measure." In response to those requests, the Public Staff revised the rule to accommodate the requests of CUCA and CIGFUR for clarification of "life of the measure." After reviewing the revisions to the rules proposed by the Public Staff and the comments of CUCA and CIGFUR, the Commission believes that much confusion regarding this provision of the rule is caused by the inherent imprecision in the phrase "life of the measure." In the Commission's opinion, the solution proposed by CUCA and CIGFUR and adopted by the Public Staff in its revision of this rule modifying the phrase by inserting "remaining" before the phrase "life of the measure or program" does not resolve and in fact compounds the confusion engendered by the use of the phrase because the phrase is capable of differing interpretations by the electric power suppliers, the industrial and large commercial customers, and other members of the rate-paying public. This confusion can only be eliminated completely by the adoption of a uniform definition of the phrase in these rules in proposed Rule R8-69(e)(3). As a result, the Commission has adopted a definition of "life of the measure" which focuses on a Commission-approved capitalization period associated with each program that is intended to provide future benefits.

Finally, the Commission's consideration of the lack of clarity in the "life of the measure" phrase also forced the Commission to focus its attention on an issue which was not raised by the parties and, as a result, not addressed by our resolution of this issue. That is, the Commission was required to determine whether it was fair and equitable to compel an industrial or large commercial customer that elects to opt back into a utility sponsored DSM or EE measure which has few, if any, costs to be capitalized for cost recovery purposes to participate in the annual rider for a minimum number of years before being allowed to again opt out of utility sponsored DSM or EE programs or measures. In the end, the Commission concluded that fairness and equity demanded that an industrial or a large commercial customer that chooses to opt back into a utility sponsored DSM or EE measure should commit to participate in utility sponsored programs for a minimum of five years or the life of the measure, whichever is longer.

In accordance with the preceding discussion, the Commission concludes that proposed Rules R8-69(e)(3) and R8-68(c)(3)(ii) should be revised to reflect the definition of the "life of the measure" and the minimum participation requirement described above. The Commission, therefore, finds good cause to amend Rule R8-69(e)(3) to read as follows:

> (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 the purposes of this subsection, "life of the measure or program" means the

> <u>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. 62-133.8(d)(1).</u> Within 30 days of the customer's election, the electric public utility shall notify the Commission of an industrial or large commercial customer that elects to participate in a new measure after having initially notified the electric public utility that it declined to participate.

The Commission further finds good cause to add a new subdivision to Rule R8-68(c)(3)(ii), as follows:

> 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. 62-133.8(d)(1).

ISSUE 99. Ability of customer to opt out of the cost of demand response programs

Demand response programs are programs under which customers reduce load in response to a request by the utility or through direct control by the utility. Duke contended that there are certain types of DSM measures offered by electric utilities that customers simply cannot implement on their own. Duke argued further that, while certain customers can control their own peak demand and, thus, their electricity costs, demand response requires that the utility take action to reduce the customer's load in order to control the utility's peak demand. Given that customers cannot implement such a program on their own, Duke urged that all customers must be assigned costs for demand response programs and that no customer should be eligible to opt out of payment for demand response programs. According to Duke, if customers are allowed to opt out of demand response programs, it is possible that only customers who participate in these programs will bear a large share of the costs, thereby making their participation uneconomical.

ED, SACE and SELC supported requiring all customers to bear the costs of demand response programs and not allowing industrials and large commercial customers to opt out of utility-sponsored DSM programs.

Nucor and CIGFUR opposed Duke's proposal.

The Commission believes that Duke's proposal directly contravenes the explicit language of Senate Bill 3, which provides that none of the costs of new demand-side management measures shall be assigned to any industrial or large commercial customer that notifies the electric supplier that it has in the past or will in the future implement alternative DSM or EE programs or measures and that the customer elects not to participate in utility-sponsored DSM or EE measures. The Commission, therefore, finds good cause to reject Duke's proposal.

ISSUE 100. Reference to net lost revenues in DSM/EE rider annual proceeding

Progress, in its initial comments, proposed that Rule R8-69(f)(1) and (2) be modified as follows:

> (f) Annual Proceeding.
>
> (1) For each electric public utility, the Commission shall schedule an annual hearing pursuant to G.S. 62-133.8(d) to review the costs incurred <u>and net lost revenues experienced</u> by the electric utility in the adoption and implementation of new demand-side management and energy efficiency measures during an historical 12-month period and shall establish an annual rider to allow the electric public utility to recover all costs and <u>net lost revenues</u> found by the Commission to be recoverable. The Commission may also approve, if appropriate, ~~the recovery of net lost revenues and other~~ electric public utility incentives pursuant to G.S. 62-133.8(d)(2) in the rider.
>
> <u>The costs 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 reasonable and prudently-incurred costs and the revenues that were actually realized during the test period under the DSM/EE 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 through the date that is thirty (30) calendar 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 DSM/EE cost recovery hearing.</u>
>
> (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, ~~appropriate~~ net lost revenues, and appropriate incentives at the same time that it files the information required by Rule R8-55.

The Public Staff, in its reply comments, recommended that the Commission not adopt the changes proposed by Progress. The Public Staff proposed that Rule R8-69(1) and (2) be modified as follows:

> (f) Annual Proceeding.
>
> (1) For each electric public utility, the Commission shall schedule an annual hearing pursuant to G.S. 62-133.8(d) to review the costs incurred by the electric utility in the adoption and implementation of new demand-side management and energy efficiency measures during <u>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</u> ~~an historical 12-month period~~ and shall establish an annual

> rider (incorporating the Prospective DSM/EE Rider and the DSM/EE EMF) 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 net lost revenues and other electric public utility incentives pursuant to G.S. 62-133.8(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, appropriate net lost revenues, and appropriate incentives at the same time that it files the information required by Rule R8-55.

Consistent with the Commission's prior discussion and conclusions regarding the proper definition of "net lost revenues" in Rule R8-68(b)(5), in which it concluded that net lost revenues are a type of utility incentive that may be recovered in an annual rider, if appropriate, the Commission rejects the changes proposed by Progress with respect to net lost revenues. However, the Commission concludes that proposed Rules R8-69(f)(1) and (2) should be modified to clarify that utility incentives may include net lost revenues. Consequently, the Commission finds that the last sentence in Rule R8-69(f)(1) should be changed as follows:

> The Commission may also approve, if appropriate, the recovery of ~~net lost revenues and other electric public~~ utility incentives, including net lost revenues, pursuant to G.S. 62-133.8(d)(2) in the rider.

In addition, the last sentence in Rule R8-69(f)(2) should be changed as follows:

> Each electric public utility shall file its application for recovery of costs~~, appropriate net lost revenues,~~ and appropriate utility incentives at the same time that it files the information required by Rule R8-55.

Regarding the changes proposed by Progress and the Public Staff in Rule R8-69(f)(1) concerning the "DSM/EE EMF" rider and the "Prospective DSM/EE Rider", those issues are addressed elsewhere herein.

ISSUE 101. Inclusion of net lost revenues in filing requirements for recovery of utility incentives

As discussed previously with respect to Rule R8-68, the Attorney General, in his reply comments, recommended that the proposed rules should allow for the recovery of net lost revenues as an incentive rather than as a cost. The Attorney General suggested that certain rules should be clarified to characterize net lost revenues as a type of incentive that may be recovered pursuant to G.S. 62-133.8(d)(2), if recovery is found to be appropriate. The Attorney General stated that the utility should have the burden of proof on the amount and with respect to the extent to which including net lost revenues in the rider is reasonable, prudent and consistent with the public interest. Therefore, the

Attorney General suggested that subsection (iv) in Rule R8-69(g)(1), concerning the filing requirements and procedure to be followed by each electric public utility, should be changed. Specifically, the Attorney General proposed that Rule R8-69(g)(1)(iv) should be modified as follows:

> For each measure for which <u>other</u> incentive recovery is requested, a detailed explanation of the method proposed for calculating those incentives, the actual calculation of the proposed incentives, and the proposed method of providing for their recovery through the annual rider.

The Public Staff, in its reply comments, proposed that proposed Rule R8-69(g)(1)(iv) be modified as follows:

> For each measure for which incentive recovery is requested <u>through the DSM/EE EMF</u>, a detailed explanation of the method proposed for calculating those incentives, the actual calculation of the proposed incentives, and the proposed method of providing for their recovery through the annual rider.

Consistent with the Commission's prior discussion and conclusions regarding the proper definition of "net lost revenues" in Rule R8-68(b)(5), wherein it concluded that net lost revenues are a type of utility incentive that may be recovered in an annual rider, if appropriate, the Commission concludes that the change proposed by the Attorney General should not be adopted and that proposed Rule R8-69(g)(1)(iii), concerning net lost revenue recovery, should be deleted. However, that language with slight modification should be included in Rule R8-69(g)(1)(iv), which concerns recovery of utility incentives. The Commission, therefore, finds that the last sentence included in Rule R8-69(g)(1)(iv) should read as follows:

> 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.

Regarding the changes proposed by the Public Staff concerning the "DSM/EE EMF", that issue is addressed elsewhere in this Order.

ISSUE 102. Confidential treatment for projected use data for industrial and large commercial accounts not subject to the DSM/EE rider

Proposed R8-69(g)(1)(vii) requires electric public utilities to include the following in their annual DSM/EE rider filing:

> Projected North Carolina Retail monthly kWh sales for the cost recovery period for all industrial and large commercial accounts that are not assessed the rider charges as provided in this rule.

Nucor stated that “[c]ustomers often consider their projected monthly kWh purchase to be commercially-sensitive information. Accordingly, such information, if presented on a customer-specific basis, should only be provided to parties subject to a protective order or a confidentiality agreement.”

CIGFUR agreed with Nucor that commercially-sensitive customer-specific information submitted in compliance with this subsection should be protected.

The proposed rules require the filing of confidential information only when absolutely necessary. In this instance, the Commission does not intend for the electric public utilities to file customer-specific data, and concludes that the rule should be clarified such that the electric public utilities are only required to file aggregated sales data for the industrial and large commercial accounts that opt out of utility DSM and EE programs.

ISSUE 103. Requirement for utilities to provide information about the cost of proposed incentives compared to the related DSM and EE costs, and the incentive’s projected effect on earnings

ED, SELC and SACE suggested that it would be useful to know (1) what the incentive amount represents as a fraction of the utility’s EE and DSM costs, as well as (2) its projected effect on the utility’s earnings. Specifically, they proposed to add a new provision to Rule R8-69(g) to require the utilities to include in their rider applications: “What the incentive amounts as calculated represent as a fraction of the utility’s related EE and DSM costs, and what the calculated incentive amounts would add to the utility’s earnings and return on equity.”

The Commission notes that projecting earnings, even current-year earnings, requires a great deal of estimation and projection about weather, sales growth, and expenses, among other things. When a utility applies for recovery of costs via the DSM/EE rider, it must document those costs. It should be an easy matter for the parties to calculate what fraction of total program costs is represented by incentives. Therefore, the Commission concludes that it is not necessary for the rules to require a calculation of the effect of proposed incentives on a utility’s projected earnings or the percentage of overall program costs that consist of incentives.

ISSUE 104. Using incentives for DSM/EE to reward excellence

ED, SELC and SACE suggested that incentives should reward some form of excellence in minimizing resource costs. They questioned whether shareholders should be rewarded for simply complying with least-cost mix requirements. They did not propose any specific performance-based incentives.

The Commission finds good cause to retain the rules as proposed, such that if a utility wants to earn incentives for DSM or EE, it must make a specific proposal to the Commission for consideration. The Commission notes that parties are free to participate and advocate for performance-based incentives in utility-specific proceedings.

ISSUE 105. Requirement to submit, in DSM/EE rider filing, information found to represent "best practices" by NAESB

In its initial comments the Public Staff proposed to add three filing requirements at R8-69(g)(1)(ii)f - h that represent NAESB "best practices":

> f. A discussion of key 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.

The Commission concludes that the unopposed additions proposed by the Public Staff are reasonable and should be included in Rule R8-69(g).

IT IS, THEREFORE, ORDERED that the Commission Rules and Regulations shall be, and hereby are, amended as set out in Appendix A, attached hereto, effective as of the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.

This the 29th day of February, 2008.

NORTH CAROLINA UTILITIES COMMISSION

Patricia Swenson

Patricia Swenson, Deputy Clerk

Sw022908.01

RULE R8-67

Chapter 1.
Practice and Procedure.

Rule R1-37 is repealed.

Rule R1-38 is repealed.

Chapter 6.
Natural Gas.

Article 14.
Incentive programs.

Rule R6-95 is added as follows:

Rule R6-95. Incentive programs for natural gas utilities.

(a) Purpose. — The purpose of this rule is to establish guidelines for the application of G.S. 62-140(c) to natural gas utilities that are consistent with the directives of that statute and consistent with the public policy of this State set forth in G.S. 62-2.

(b) Definitions. — As used in this rule, the following definitions shall apply:

(1) “Consideration” means anything of economic value paid, given or offered to any person by a natural gas utility (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 natural gas utility; 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.

(2) “Program” means any natural gas utility action or planned action that involves offering Consideration.

(3) “Person” means the same as defined in G.S. 62-3(21).

(4) “Natural gas utility” means, for purposes of this rule, a person, whether organized under the laws of this State or under the laws of any other state or country, that owns or operates in the State equipment

or facilities for producing, transporting, distributing, or furnishing piped gas to or for the public for consumption.

(c) Filing for Approval.

(1) Application of Rule. — Prior to a natural gas utility implementing any Program, the purpose or effect of which is to directly or indirectly alter or influence the decision to use the natural gas utility's service for a particular end-use or to directly or indirectly encourage the installation of equipment that uses the natural gas utility's service, the natural gas utility shall obtain Commission approval.

Whether a Program is offered at the expense of the natural gas utility's shareholders, ratepayers or a third party shall not affect the filing requirements under this rule.

A natural gas utility shall file for approval all Programs to offer Consideration which are administered, promoted or funded by the natural gas utility's subsidiaries, affiliates and/or unregulated divisions or businesses where the natural gas utility has control over the entity offering or is involved in the Program and an intent or effect of the Program is to adopt, secure, or increase the use of the natural gas utility's utility services.

(2) Filing Requirements. — Each application for the approval of a Program shall include the following:

(i) Cover Page. — The natural gas utility shall attach to the front of an application a cover sheet generally describing the Program, the Consideration to be offered, anticipated total cost of the Program, the source and amount of funding proposed to be used, proposed classes of persons to whom it will be offered, and the duration of the Program.

(ii) Description. — A detailed description of the Program, its duration, purpose, estimated number of participants, and impact on the natural gas utility's general body of customers and the natural gas utility.

(iii) Cost. — The estimated total and per unit cost for the Program to the natural gas utility, reported by type of expenditure (e.g., direct payment, rebate, advertising) and the planned accounting treatment for those costs. If the natural gas utility proposes to place any costs to be incurred in a deferred account for possible future recovery from its customers, it shall disclose the same and provide an estimate of each cost to be deferred. The natural gas utility shall describe, in detail, all other sources of monies to be used, including the name of the source, the amount provided, and the reasons the third party is providing the money.

(iv) Effect on Customer Use. — A statement of the effect, if any, that the Program is expected to have on customer use of the natural gas utility's service.

(v) Conditions of Program. — The type and amount of Consideration and how and to whom it will be offered or paid, including schedules listing the Consideration to be offered, a list of those who will use the natural gas utility's service, and other information on the availability and limitations (who can and cannot participate) of the Consideration. The natural gas utility shall describe any service limitations or conditions it imposes on customers who do not participate in the Program.

(vi) Economic Justification. — Economic justification for the Program, including the results of appropriate cost-effectiveness tests.

(vii) Communications. — Detailed cost information on the amount the natural gas utility anticipates will be spent on communication materials related to the Program. Such cost shall be included in the Commission's consideration of the total cost of the Program and whether the total cost of the Program is reasonable in light of the benefits. To the extent available, the natural gas utility shall include examples of all communication materials to be used in conjunction with the Program.

(viii) Commission Guidelines Regarding Incentive Programs. — The natural gas utility 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.

(ix) Other. — Any other information the natural gas utility believes relevant to the application, including information on competition faced by the natural gas utility.

(d) Procedure.

(1) Service and Response. — The natural gas utility filing for approval of a Program shall serve a copy of its filing on the electric utilities and electric membership corporations operating within the filing natural gas utility's certificated territory, the Public Staff, the Attorney General and any other party that has notified the natural gas utility in writing that it wishes to be served with copies of all such filings that involve the provision of Consideration. Those served, and others learning of the application, shall have thirty (30) days from the date of filing in which to seek intervention pursuant to Rule R1-19 or file a protest pursuant to Rule R1-6. The filing natural gas utility shall have the opportunity to respond to such petitions or protests within ten (10) days of their filing. If any party granted intervention requests a hearing or otherwise raises a material issue of fact, the Commission may, in its discretion, set the matter for hearing.

(2) Notice and Schedule. — If the application is set for hearing, the Commission shall require such notice as it deems 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 considering whether to approve in whole or in part a Program or changes to an existing Program, the Commission may consider any other information it determines to be relevant, including, but not limited to, the following issues:

(1) Whether the Program unreasonably discriminates among persons receiving or applying for the same kind and degree of service;

(2) Evidence of consideration or compensation paid by any competitor, regulated or unregulated, of the natural gas utility to secure the installation or adoption of the use of such competitor's services;

(3) Whether the 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

(4) Whether the Program encourages energy efficiency and its impact on the peak loads and load factors of the filing natural gas utility.

Chapter 8.
Electric Light and Power.

Article 10.
Fuel Based Rate Changes.

Rule R8-52 is rewritten as follows:

Rule R8-52. Monthly fuel report.

(a) On or before the 15th day of each month, each electric public utility which uses fossil and/or nuclear fuel in the generation of electric power for providing North Carolina retail electric service shall file a Fuel Report for the second preceding month (i.e., up to 45 days after the end of the month being reported) for review by the Commission, the Public Staff, and any other interested party. The Monthly Fuel Report shall be filed in such formats as shall from time to time be approved by the Commission, and shall include the following information:

(1) Details of power plant performance and generation;

(2) Details of cost of fuel burned;

(3) Details of cost of fuel transportation;

(4) Details of fuel consumption and inventories;

(5) Analysis of fossil fuel purchases;

(6) Details of cost and inventories of ammonia, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions;

(7) Details of transactions for purchases, sales, and interchanges of power, including (i) total delivered noncapacity related costs of purchases that are subject to economic dispatch or economic curtailment and (ii) capacity costs associated with purchases from qualifying cogeneration facilities and qualifying small power production facilities, as defined in 16 U.S.C. 796, that are subject to economic dispatch;

(8) Details of the total delivered costs of purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.7 and costs incurred to comply with any federal mandate that is similar to subsections (b), (d), (e), and (f) of G.S. 62-133.7;

(9) Details of the fuel cost component of other purchased power;

(10) Details of net gains or losses resulting from sales of fuel or other fuel-related costs components as defined in G.S. 62-133.2(a1);

(11) Details of net gains or losses resulting from sales of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs as defined in G.S. 62-133.2(a1); and

(12) Details of costs incurred to comply with the Swine Farm Methane Capture Pilot Program established in Section 4 of S.L. 2007-523.

Subdivisions (6) and (7)(ii) of this subsection do not apply to the Monthly Fuel Report of an electric public utility that is subject to G.S. 62-133.2(a3).

(b) Each electric public utility which uses fossil and/or nuclear fuel in the generation of electric power shall file a Fuel Procurement Practices Report for review by the Commission at least once every ten (10) years, plus each time the utility's fuel procurement practices change. The Fuel Procurement Practices Report shall detail:

(1) The process and/or methodology the utility uses to determine its fuel and fuel-related needs;

(2) The process the utility uses to determine from which vendor it shall buy fuel and fuel-related inventories; and

(3) The inventory management practices the utility follows to maintain its fuel and fuel-related inventories.

Rule R8-55 is rewritten as follows:

Rule R8-55. Annual hearings to review changes in the cost of fuel and fuel-related costs.

(a) As used in this rule, "cost of fuel and fuel-related costs" means all of the following:

(1) The cost of fuel burned.

(2) The cost of fuel transportation.

(3) The cost of ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions.

(4) The total delivered noncapacity related costs, including all related transmission charges, of all purchases of electric power by the electric public utility that are subject to economic dispatch or economic curtailment.

(5) The capacity costs associated with all purchases of electric power from qualifying cogeneration facilities and qualifying small power production facilities, as defined in 16 U.S.C. 796, that are subject to economic dispatch by the electric public utility.

(6) Except for those costs recovered pursuant to G.S. 62-133.7(h), the total delivered costs of all purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.7 or to comply with any federal mandate that is similar to the requirements of subsections (b), (d), (e) and (f) of G.S. 62-133.7.

(7) All costs incurred to comply with the Swine Farm Methane Capture Pilot Program established in Section 4 of S.L. 2007-523.

(8) The fuel cost component of other purchased power.

Cost of fuel and fuel-related costs shall be adjusted for (a) any net gains or losses resulting from any sales by the electric public utility of fuel and other fuel-related costs components and (b) any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs.

(b) For each electric public utility generating electric power by means of fossil and/or nuclear fuel for the purpose of furnishing North Carolina retail electric service, the Commission shall schedule an annual public hearing pursuant to G.S. 62-133.2(b) in order to review changes in the electric public utility's cost of fuel and fuel-related costs. The annual cost of fuel and fuel-related cost adjustment hearing for Duke Energy Carolinas, LLC, will be scheduled for the first Tuesday of June each year; for Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., the annual hearing will be scheduled for the third Tuesday of September each year; and for Virginia Electric and Power

Company, d/b/a Dominion North Carolina Power, the annual hearing will be scheduled for the second Tuesday of November each year.

(c) The test periods for the hearings to be held pursuant to paragraph (b) above will be uniform over time. The test period for Duke Energy Carolinas, LLC will be the calendar year; for Progress Energy Carolinas, Inc., the test period will be the 12-month period ending March 31; and for Dominion North Carolina Power, the test period will be the 12-month period ending June 30.

(d) The Commission shall permit each electric public utility to charge an increment or decrement as a rider to its rates for changes in the cost of fuel and fuel-related costs used in providing its North Carolina customers with electricity from the cost of fuel and fuel-related costs established in the electric public utility's previous general rate case on the basis of cost per kilowatt-hour. The increment or decrement may be different among customer classes. The general methodology and procedures to be used in establishing the cost of fuel and fuel-related costs shall be as follows:

(1) Cost of fuel and fuel-related costs will be preliminarily established utilizing the methods and procedures approved in the utility's last general rate case, except that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation's Generating Availability Report, adjusted to reflect unique, inherent characteristics of the utility, including, but not limited to, plants 2 years or less in age and unusual events. The national average capacity factor for nuclear production facilities shall be based on the most recent 5-year period available and shall be weighted, if appropriate, for both pressurized water reactors and boiling water reactors. The costs shall be allocated among customer classes in accordance with G.S. 62-133.2(a2), as applicable. A cost of fuel and fuel-related cost rider will then be determined based upon the difference between the cost of fuel and fuel-related costs thus established and the base cost of fuel and fuel-related cost component of the rates established in the utility's most recent general rate case. The foregoing normalization requirement assumes that the Commission finds that an abnormality having a probable impact on the utility's revenues and expenses existed during the test period.

(2) Cost of fuel and fuel-related costs will be modified as provided in G.S. 62-133.2(a3).

(3) The cost of fuel and fuel-related costs as described above will be further modified through use of an experience modification factor (EMF) rider, which may be different among customer classes. The EMF rider will reflect the difference between reasonable and prudently incurred cost of fuel and fuel-related costs and the fuel-related revenues that were actually realized during the test period under the cost of fuel and fuel-related cost components of rates 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 cost of fuel and fuel-related 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 fuel and fuel-related costs adjustment hearing.

(4) The cost of fuel and fuel-related cost rider and the EMF rider as described hereinabove will be charged as an increment or decrement to the base fuel cost component of rates established in the electric public utility's previous general rate case.

(5) The 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; provided, however, that such carry-through provision will not relieve the Commission of its responsibility to determine the reasonableness of the cost of fuel and fuel-related costs, other than that being collected through operation of the EMF rider, in any intervening general rate case proceeding.

(6) Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred cost of fuel and fuel-related costs to be refunded to a utility's customers through operation of the 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.

(e) Each electric public utility, at a minimum, shall submit to the Commission for purposes of investigation and hearing the information and data in the form and detail as set forth below:

(1) Actual test period kWh sales, peak demand by customer class, fuel-related revenues, and fuel-related expenses for the utility's total system and for its North Carolina retail operations.

(2) Test period kWh sales normalized for weather, customer growth and usage. Said normalized kWh sales shall be for the utility's total system and for its North Carolina retail operations. The methodology used for such normalization shall be the same methodology adopted by the Commission, if any, in the utility's last general rate case.

(3) Adjusted test period kWh generation corresponding to normalized test period kWh usage. The methodology for such adjustment shall be the same methodology adopted by the Commission in the utility's last general rate case, including adjustment by type of generation; i.e., nuclear, fossil, hydro, pumped storage, purchased power, etc. In the event that said methodology is inconsistent with the normalization methodology set forth in paragraph (d)(1) above, additional pro forma calculations shall be presented incorporating the normalization methodology reflected in paragraph (d)(1).

(4) Cost of fuel and applicable fuel-related costs corresponding to the adjusted test period kWh generation, including a detailed

explanation showing how such cost of fuel and fuel-related costs were derived. The cost of fuel shall be based on end-of-period unit fuel prices incurred during the test period, although the Commission may consider other fuel prices if test period fuel prices are demonstrated to be nonrepresentative on an on-going basis. Unit fuel prices shall include delivered fuel prices and burned fuel expense rates as appropriate.

(5) Procurement practices and inventories for fuel burned and for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions.

(6) The cost of fuel burned and of ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions at each generating facility.

(7) Any net gains or losses resulting from any sales by the electric public utility of fuel or other fuel-related costs components.

(8) Any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs.

(9) All costs incurred to comply with the Swine Farm Methane Capture Pilot Program established in Section 4 of S.L. 2007-523.

(10) The monthly fuel report and the monthly base load power plant performance report for the last month in the test period and any information required by Rules R8-52 and R8-53 for the test period which has not already been filed with the Commission. Further, such information for the complete 12-month test period shall be provided by the electric public utility to any intervenor upon request.

(11) All workpapers supporting the calculations, adjustments and normalizations described above.

(12) The nuclear capacity rating(s) in the last rate case and the rating(s) proposed in this proceeding. If they differ, supporting justification for the change in nuclear capacity rating(s) since the last rate case.

(13) The proposed rate design to recover the electric public utility's cost of fuel and fuel-related costs.

An electric public utility that is subject to G.S. 62-133.2(a3) is required to provide only the applicable information prescribed by subdivisions (5), (6) and (8) of this subsection.

(f) The 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 herein, and any changes in rates proposed by the electric public utility (if any), according to the following schedule: Duke Energy Carolinas, LLC, and Progress Energy Carolinas, Inc., not less than 90 days prior to the hearing; Dominion North Carolina Power, not less than 75 days prior to the hearing. Nothing in this rule shall be construed to require the electric public utility to propose a change in rates or to utilize any particular methodology to calculate any change in rates proposed by the utility in this proceeding.

(g) The electric public utility shall publish a notice for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least 30 days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-133.2(b) and setting forth the time and place of the hearing.

(h) 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.

(i) 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.

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

(k) The burden of proof as to the correctness and reasonableness of any charge and as to whether the test year cost of fuel and fuel-related costs were reasonable and prudently incurred shall be on the utility. For purposes of determining the EMF rider, a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability Corporation's Generating Availability Report, appropriately weighted for size and type of plant or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability Corporation's Generating Availability Report, appropriately weighted for size and type of plant, or a presumption will be created that the utility incurred the increased cost of fuel and fuel-related costs resulting therefrom imprudently and that disallowance thereof is appropriate. The utility shall have the opportunity to rebut this presumption at the hearing and to prove that its test year cost of fuel and fuel-related costs were reasonable and prudently incurred. To the extent that the utility rebuts the presumption by the preponderance of the evidence, no disallowance will result.

(l) The hearing will generally be held in the Hearing Room of the Commission at its offices in Raleigh, North Carolina.

(m) Each electric public utility shall follow deferred accounting with respect to the difference between actual reasonable and prudently incurred cost of fuel and fuel-related costs and cost of fuel and fuel-related costs recovered under rates in effect.

(n) If the Commission has not issued an order pursuant to G.S. 62-133.2 within 180 days after the date the electric public utility has filed any proposed changes in its rates and charges in this proceeding based solely on the cost of fuel and fuel-related costs, then the utility may place such proposed changes into effect. If such changes in the rates and charges are finally determined to be excessive, the electric public utility shall refund any excess plus interest to its customers in a manner directed by the Commission.

Article 11.
Resource Planning and Certification.

Rule R8-60 is rewritten as follows:

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 Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; Virginia Electric and Power Company, d/b/a Dominion North Carolina Power; the North Carolina Electric Membership Corporation; and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources.

(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. 62-133.8(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. 62-133.7.

(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 annual 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. — Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power shall provide information on levelized busbar costs for various generation technologies.

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

Rule R8-61 is rewritten as follows:

Rule R8-61. Preliminary plans and certificates of public convenience and necessity for construction of electric generation and related transmission facilities in North Carolina; construction of out-of-state electric generating facilities; progress reports and ongoing reviews of construction; project development cost reviews for nuclear generating facilities.

(a) Information to be filed 120 or more days before the filing of an application, by a public utility or other person, for a certificate of public convenience and necessity for generating facilities with capacity of 300 MW or more shall include the following:

(1) Available site information (including maps and description), preliminary estimates of initial and ultimate development, justification for

the adoption of the site selected, and general information describing the other locations considered;

(2) As appropriate, preliminary information concerning geological, aesthetic, ecological, meteorological, seismic, water supply, population and general load center data to the extent known;

(3) A statement of the need for the facility, including information on loads and generating capability;

(4) A description of investigations completed, in progress, or proposed involving the subject site;

(5) A statement of existing or proposed plans known to the applicant of federal, state, local governmental and private entities for other developments at or adjacent to the proposed site;

(6) A statement of existing or proposed environmental evaluation programs to meet the applicable air and water quality standards;

(7) A brief general description of practicable transmission line routes emanating from the site;

(8) A list of all agencies from which approvals will be sought covering various aspects of any generation facility constructed on the site and the title and nature of such approvals;

(9) A statement of estimated cost information, including plans and related transmission capital cost (initial core costs for nuclear units); all operating expenses by categories, including fuel costs and total generating cost per net kWh at plant; and information concerning capacity factor, heat rate, and plant service life. Furnish comparative cost including related transmission cost of other final alternatives considered; and

(10) A schedule showing the anticipated beginning dates for construction, testing, and commercial operation of the generating facility.

(b) In filing an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) in order to construct a generating facility in North Carolina, a public utility shall include the following information supported by relevant testimony:

(1) The most recent biennial report and the most recent annual report (as defined in Rule R8-60) of the utility plus any proposals by the utility to update said report;

(2) The extent to which the proposed construction conforms to the utility's most recent biennial report and the most recent annual report (as defined in Rule R8-60);

(3) Support for any utility proposals to update its most recent biennial report and its most recent annual report (as defined in Rule R8-60);

(4) Updates, if any, to the Rule R8-61(a) information;

(5) An estimate of the construction costs for the generating facility;

(6) The projected cost of each major component of the generating facility and the projected schedule for incurring those costs;

(7) The projected effect of investment in the generating facility on the utility's overall revenue requirement for each year during the construction period;

(8) The anticipated construction schedule for the generating facility;

(9) The specific type of units selected for the generating facility; the suppliers of the major components of the facility; the basis for selecting the type of units, major components, and suppliers; and the adequacy of fuel supply;

(10) The qualifications and selection of principal contractors and suppliers for construction of the generating facility, other than those listed in Item (9) above;

(11) Resource and fuel diversity and reasonably anticipated future operating costs, including the anticipated in-service expenses associated with the generating facility for the 12-month period of time following commencement of commercial operation of the facility;

(12) Risk factors related to the construction and operation of the generating facility; and

(13) If the application is for a coal or nuclear generating facility, information demonstrating that energy efficiency measures; demand-side management; renewable energy resource generation; combined heat and power generation; or any combination thereof, would not establish or maintain a more cost-effective and reliable generation system and that the construction and operation of the facility is in the public interest.

(c) The public utility shall submit a progress report and any revision in the construction cost estimate during each year of construction according to a schedule established by the Commission.

(d) Upon the request of the public utility or upon the Commission's own motion, the Commission may conduct an ongoing review of construction of the generating facility as the construction proceeds.

(e) A public utility requesting an ongoing review of construction of the generating facility pursuant to G.S. 62-110.1(f) shall file an application, supported by relevant testimony, for an ongoing review no later than 12 months after the date of issuance of a certificate of public convenience and necessity by the Commission; provided, however, that the public utility may, prior to the conclusion of such 12-month period, petition the Commission for a reasonable extension of time to file an application based on a showing of good cause. Upon the filing of a request for an ongoing review, the Commission shall establish a schedule of hearings. The hearings shall be held no more often than every 12 months. The Commission shall also establish the time period to be reviewed during each hearing. The purpose of each ongoing review hearing is to determine the reasonableness and prudence of the costs incurred by the public utility during the period under review and to determine whether the certificate should remain in effect or be modified or revoked. The public utility shall have the burden of proof to demonstrate that all costs incurred are reasonable and prudent.

(f) A public utility may file an application pursuant to G.S. 62-110.6 requesting the Commission to determine the need for an out-of-state electric generating facility that is intended to serve retail customers in North Carolina. If need for the generating facility is established, the Commission shall also approve an estimate of the construction costs and construction schedule for such facility. The application may be filed at any time after an application for a certificate of public convenience and necessity or license for construction of the generating facility has been filed in the state in which the facility will be sited. The application shall be supported by relevant testimony and shall include the information required by subsection (b) of this Rule to the extent such information is relevant to the showing of need for the generating facility and the estimated construction costs and proposed construction schedule for the generating facility. The public utility shall submit a progress report and any revision in the construction cost estimate for the out-of-state electric generating facility during each year of construction according to a schedule established by the Commission.

(g) If the Commission makes a determination of need pursuant to G.S. 62-110.6 and subsection (f) of this Rule, the provisions of subsections (d) and (e) of this Rule shall apply to a request by a public utility for an ongoing review of construction of a generating facility to be constructed in another state that is intended to serve retail customers in North Carolina. An electric public utility shall file an application, supported by relevant testimony, for an ongoing review no later than 12 months after the date of issuance of a certificate of public convenience and necessity or license by the state commission in which the out-of-state generating facility is to be constructed; provided, however, that the public utility may, prior to the conclusion of such 12-month period, petition the Commission for a reasonable extension of time to file an application based on a showing of good cause.

(h) A public utility may file an application pursuant to G.S. 62-110.7 requesting the Commission to review the public utility’s decision to incur project development costs for a potential in-state or out-of-state nuclear generating facility that is intended to serve retail electric customers in North Carolina. The application, supported by relevant testimony, shall be filed prior to the filing of an application for a certificate to construct the facility.

Rule R8-64 is added as follows:

Rule R8-64. Application for certificate of public convenience and necessity by qualifying cogenerator or small power producer; progress reports.

(a) Scope of Rule.

(1) This rule applies to applications for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) filed by any person seeking the benefits of 16 U.S.C. 824a-3 or G.S. 62-156 as a qualifying cogenerator or a qualifying small power producer as defined in 16 U.S.C. 796(17) and (18) or as a small power producer as defined in G.S. 62-3(27a), except persons exempt from certification by the provisions of G.S. 62-110.1(g).

(2) For purposes of this rule, the term “person” shall include a municipality as defined in Rules R7-2(c) and R10-2(c), including a county of the State.

(3) The construction of a facility for the generation of electricity shall include not only the building of a new building, structure or generator, but also the renovation or reworking of an existing building, structure or generator in order to enable it to operate as a generating facility.

(4) This rule shall apply to any person within its scope who begins construction of an electric generating facility without first obtaining a certificate of public convenience and necessity. In such circumstances, the application shall include an explanation for the applicant’s beginning of construction before the obtaining of the certificate.

(b) The Application.

(1) The application shall be accompanied by maps, plans, and specifications setting forth such details and dimensions as the Commission requires. It shall contain, among other things, the following information, either embodied in the application or attached thereto as exhibits:

(i) The full and correct name, business address and business telephone number of the applicant;

(ii) A statement of whether the applicant is an individual, a partnership, or a corporation and, if a partnership, the name and business address of each general partner and, if a corporation, the state and date of incorporation and the name and business address of an individual duly authorized to act as corporate agent for the purpose of the application and, if a foreign corporation, whether domesticated in North Carolina;

(iii) The nature of the generating facility, including the type and source of its power or fuel;

(iv) The location of the generating facility set forth in terms of local highways, streets, rivers, streams, or other generally known local landmarks together with a map, such as a county road map, with the location indicated on the map;

(v) The ownership of the site and, if the owner is other than the applicant, the applicant's interest in the site;

(vi) A description of the buildings, structures and equipment comprising the generating facility and the manner of its operation;

(vii) The projected maximum dependable capacity of the facility in megawatts;

(viii) The projected cost of the facility;

(ix) The projected date on which the facility will come on line;

(x) The applicant's general plan for sale of the electricity to be generated, including the utility to which the applicant plans to sell the electricity; any provisions for wheeling of the electricity; arrangements for firm, non-firm or emergency generation; the service life of the project; and the projected annual sales in kilowatt-hours; and

(xi) A complete list of all federal and state licenses, permits and exemptions required for construction and operation of the generating facility and a statement of whether each has been obtained or applied for. A copy of those that have been obtained should be filed with the application; a copy of those that have not been obtained at the time of the application should be filed with the Commission as soon as they are obtained.

(2) In addition to the information required above, an applicant who desires to enter into a contract for a term of 5 years or more for the sale of electricity and who will have a projected dependable capacity of 5 megawatts or more available for such sale shall include in the application the following information and exhibits:

(i) A statement detailing the experience and expertise of the persons who will develop, design, construct and operate the project to the extent such persons are known at the time of the application;

(ii) Information specifically identifying the extent to which any regulated utility will be involved in the actual operation of the project;

(iii) A statement obtained by the applicant from the electric utility to which the applicant plans to sell the electricity to be generated setting forth an assessment of the impact of such purchased power on the utility's capacity, reserves, generation mix, capacity expansion plan, and avoided costs;

(iv) The most current available balance sheet of the applicant;

(v) The most current available income statement of the applicant;

(vi) An economic feasibility study of the project;

(vii) A statement of the actual financing arrangements entered into in connection with the project to the extent known at the time of the application;

(viii) A detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year;

(ix) A detailed explanation of all energy inputs and outputs, of whatever form, for the project, including the amount of energy and the form of energy to be sold to each purchaser; and

(x) A detailed explanation of arrangements for fuel supply, including the length of time covered by the arrangements, to the extent known at the time of the application.

(3) All applications shall be signed and verified by the applicant or by an individual duly authorized to act on behalf of the applicant for the purpose of the application.

(4) Applications filed on behalf of a corporation are not subject to the provision of R1-5(d) that requires corporate pleadings to be filed by a member of the Bar of the State of North Carolina. Should a public hearing be required, the requirements of G.S. 84-4 and G.S. 84-4.1 shall be applicable.

(5) Falsification of or failure to disclose any required information in the application may be grounds for denying or revoking any certificate.

(6) The application and 30 copies shall be filed with the Chief Clerk of the Utilities Commission.

(c) Procedure upon receipt of Application. — Upon the filing of an application appearing to meet the requirements set forth above, the Commission will process it as follows:

(1) The Commission will issue an order requiring the applicant to publish notice of the application once a week for four successive weeks in a daily newspaper of general circulation in the county where the generating facility is proposed to be constructed and requiring the applicant to mail a copy of the application and the notice, no later than the first date that such notice is published, to the electric utility to which the applicant plans to sell the electricity to be generated. The applicant shall be responsible for filing with the Commission an affidavit of publication and a signed and verified certificate of service to the effect that the application and notice have been mailed to the electric utility to which the applicant plans to sell the electricity to be generated.

(2) The Chief Clerk will deliver 16 copies of the application and the notice to the Clearinghouse Coordinator of the Office of Policy and

Planning of the Department of Administration for distribution by the Coordinator to State agencies having an interest in the application.

(3) If a complaint is received within 10 days after the last date of the publication of the notice, the Commission will schedule a public hearing to determine whether a certificate should be awarded and will give reasonable notice of the time and place of the hearing to the applicant and to each complaining party and will require the applicant to publish notice of the hearing in the newspaper in which the notice of the application was published. If no complaint is received within the time specified, the Commission may, upon its own initiative, order and schedule a hearing to determine whether a certificate should be awarded and, if the Commission orders a hearing upon its own initiative, it will require notice of the hearing to be published by the applicant in the newspaper in which the notice of the application was published.

(4) If no complaint is received within the time specified and the Commission does not order a hearing upon its own initiative, the Commission will enter an order awarding the certificate.

(d) The Certificate.

(1) The certificate shall be subject to revocation if any of the other federal or state licenses, permits or exemptions required for construction and operation of the generating facility is not obtained and that fact is brought to the attention of the Commission and the Commission finds that as a result the public convenience and necessity no longer requires, or will require, construction of the facility.

(2) The certificate must be renewed by re-compliance with the requirements set forth in this Rule if the applicant does not begin construction within 5 years after issuance of the certificate.

(3) Both before the time construction is completed and after, all certificate holders must advise both the Commission and the utility involved of any plans to sell, transfer, or assign the certificate or the generating facility or of any significant changes in the information set forth in subsection (b)(1) of this Rule, and the Commission will order such proceedings as it deems appropriate to deal with such plans or changes.

(e) Reporting. — All applicants must submit annual progress reports until construction is completed.

Rule R8-65 is added as follows:

Rule R8-65. Report by persons constructing electric generating facilities exempt from certification requirement.

(a) All persons exempt from certification under G.S. 62-110.1(g) shall file with the Commission a report of the proposed construction of an electric generating facility before beginning construction of the facility. The report of proposed construction shall include the information prescribed in subsection (b)(1) of Rule R8-64 and shall be signed and verified by the owner of the electric generating facility or by an individual duly authorized to act on behalf of the owner for the purpose of the filing.

(b) Reports filed on behalf of a corporation are not subject to the provision of Rule R1-5(d) that requires corporate pleadings to be filed by a member of the Bar of the State of North Carolina. Should a public hearing be required, the requirements of G.S. 84-4 and G.S. 84-4.1 shall be applicable.

(c) The owner of the electric generating facility shall provide a copy of the report of proposed construction to the electric public utility, electric membership corporation, or municipality to which the generating facility will be interconnected.

(d) The owner of the electric generating facility shall file an original and 30 copies of the report of proposed construction with the Chief Clerk of the Utilities Commission. No filing fee is required.

(e) Upon the filing of a report of proposed construction, the Chief Clerk will assign a new docket or sub-docket number to the filing and will deliver 16 copies of the report of proposed construction to the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration for distribution by the Coordinator to State agencies having an interest for information only.

(f) The Commission may order a hearing on the report of proposed construction upon its own motion or upon receipt of a complaint specifying the basis thereof. Otherwise, no acknowledgment of receipt of the report of proposed construction will be issued nor will any other further action be taken by the Commission.

Rule R8-66 is added as follows:

Rule R8-66. Registration of renewable energy facilities; annual reporting requirements.

(a) The following terms shall be defined as provided in G.S. 62-133.7: “electric power supplier”; “renewable energy certificate”; and “renewable energy facility.”

(b) The owner, including an electric power supplier, of each renewable energy facility, whether or not required to obtain a certificate of public convenience and necessity pursuant to G.S. 62-110.1, that intends for renewable energy certificates it earns to be eligible for use by an electric power supplier to comply with G.S. 62-133.7 shall register with the Commission. The registration statement may be filed separately or together with an application for a certificate of public convenience and necessity, with a report of proposed construction by a person exempt from the certification requirement, or by an electric power supplier with a compliance plan under Rule R8-67(b) if the facility is owned by the electric power supplier or under contract to the electric power supplier as of the effective date of this rule. All relevant renewable energy facilities shall be registered prior to the electric power supplier filing its REPS compliance report pursuant to Rule R8-67(c). Contracts for power supplied by an agency of the federal government are exempt from the requirement to register and file annually with the Commission if the renewable energy certificates associated with the power are bundled with the power purchased by the electric power supplier.

(1) The owner of each renewable energy facility that has not previously done so, including a facility that is located outside of the State of North Carolina, shall include in its registration statement the information set forth in paragraphs (i) through (v) and paragraph (xi) of subsection (b)(1) of Rule R8-64, a description of the technology used to produce electricity, and the facility's projected dependable capacity in megawatts by generating unit. If the facility is not yet completed and in operation, the owner shall also file the information prescribed in paragraph (ix) of subsection (b)(1) of Rule R8-64.

(2) The owner of each renewable energy facility required to file Form EIA-923 with the Energy Information Administration (EIA), United States Department of Energy, shall include with its registration statement a copy of Schedules 1, 5, 6 and 9 from its most recent Form EIA-923 and shall file a copy of those Schedules with the Commission each year at the same time the information is provided to the EIA. The owner of a renewable energy facility that is not required to file Form EIA-923 with the EIA shall nevertheless file the information required by Schedules 1, 5, 6 and 9 with its registration statement and by April 1st of each year thereafter.

(3) The owner of each renewable energy facility shall certify in its registration statement and annually thereafter that it is in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources. If a credible showing is made that the facility is not in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources, the Commission shall refer the matter to the appropriate environmental agency for review. Registration shall not be revoked unless and until the appropriate environmental agency concludes that the facility is out of compliance and the Commission issues an order revoking the registration.

(4) The owner of each renewable energy facility shall certify in its registration statement and annually thereafter that the facility satisfies the requirements of G.S. 62-133.7(a)(5) or (7) as a renewable energy facility or new renewable energy facility, that the facility will be operated as a renewable energy facility or new renewable energy facility, and, if the

facility has been placed into service, the date when it was placed into service.

(5) The owner of each renewable energy facility shall further certify in its registration statement and annually thereafter that any renewable energy certificates (whether or not bundled with electric power) sold to an electric power supplier to comply with G.S. 62-133.7 have not, and will not, be remarketed or otherwise resold for any other purpose, including another renewable energy portfolio standard or voluntary purchase of renewable energy certificates in North Carolina or any other state or country, and that the electric power associated with the certificates will not be offered or sold with any representation that the power is bundled with renewable energy certificates. The owner shall also annually report whether it sold any renewable energy certificates (whether or not bundled with electric power) during the prior year and, if so, how many and to whom.

(6) The owner of each renewable energy facility shall certify in its registration statement and annually thereafter that it consents to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers, and agrees to provide the Public Staff and the Commission access to its books and records, wherever they are located, and to the facility.

(7) Each registration statement shall be signed and verified by the owner of the renewable energy facility or by an individual duly authorized to act on behalf of the owner for the purpose of the filing.

(8) Registration statements filed on behalf of a corporation are not subject to the provision of Rule R1-5(d) that requires corporate pleadings to be filed by a member of the Bar of the State of North Carolina. Should a public hearing be required, the requirements of G.S. 84-4 and G.S. 84-4.1 shall be applicable.

(9) An original and 30 copies of the registration statement shall be filed with the Chief Clerk of the Utilities Commission. No filing fee is required to be submitted with the registration statement.

(c) Each re-seller of renewable energy certificates derived from a renewable energy facility, including a facility that is located outside of the State of North Carolina, shall ensure that the owner of the renewable energy facility registers with the Commission prior to the sale of the certificates by the re-seller to an electric power supplier to comply with G.S. 62-133.7(b), (c), (d), (e) and (f), except that the filing requirements in subsection (b) of this Rule shall apply only to information for the year(s) corresponding to the year(s) in which the certificates to be sold were earned.

(d) Upon receipt of a registration statement, the Chief Clerk will assign a new docket or sub-docket number to the filing. The Chief Clerk will deliver 16 copies of the registration statement to the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration for distribution by the Coordinator to State agencies having an interest in the filing for information only.

(e) No later than ten (10) business days after the registration statement is filed with the Commission, the Public Staff shall, and any other interested persons may, file with the Commission and serve upon the registrant a recommendation regarding whether the registration statement is complete and identifying any deficiencies. If the Commission determines that the registration statement is not complete, the owner of the renewable energy facility will be required to file the missing information. Upon receipt of all required information, the Commission will promptly issue an order accepting the registration or setting the matter for hearing.

(f) Any of the following actions may result in revocation of registration by the Commission:

(1) falsification of or failure to disclose any required information in the registration statement or annual filing;

(2) failure to remain in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources;

(3) remarketing or reselling any renewable energy certificate (whether or not bundled with electric power) after it has been sold to an electric power supplier or any other person for compliance with G.S. 62-133.7 or for any other purpose, including another renewable energy portfolio standard or voluntary purchase of renewable energy certificates in North Carolina or any other state or country, or offering or selling the electric power associated with the certificates with any representation that the power is bundled with renewable energy certificates; or

(4) failure to allow the Commission or the Public Staff access to its books and records necessary to audit REPS compliance.

Rule R8-67 is added as follows:

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

(a) Definitions.

(1) The following terms shall be defined as provided in G.S. 62-133.7: “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) “Avoided cost rates” mean an electric power supplier’s most recently approved or established avoided cost rates in North Carolina, as

of the date the contract is executed, for purchases of electricity from qualifying facilities pursuant to the provisions of 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 such a 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; provided, however, that development of such estimates of avoided cost by an electric public utility shall include consideration of the avoided cost rates then in effect as established by the Commission. 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 and, unless approved otherwise by the Commission pursuant to subsection (c)(4), determined in the same manner as that information is reported to the Energy Information Administration (EIA), United States Department of Energy, for annual electric sales and revenues reporting.

(b) REPS compliance plan.

(1) Each year, beginning in 2008, each electric power supplier shall file with the Commission the electric power supplier's plan for complying with G.S. 62-133.7(b), (c), (d), (e) and (f). The plan shall cover at least the current and 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. 62-133.7(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 planned or implemented energy efficiency measures, including a brief description of the measure and projected impacts;

(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) the electric power supplier's registration information and certified statements required by Rule R8-66, to the extent they have not already been filed with the Commission.

(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. 62 133.7(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 shall file with the Commission a report describing the electric power supplier's compliance with the requirements of G.S. 62-133.7(b), (c), (d), (e) and (f) during the previous calendar year. The report shall include all of

the following information, including supporting documentation and direct testimony and exhibits of expert witnesses:

(i) the sources, amounts, and costs of renewable energy certificates, by source, used to comply with G.S. 62-133.7(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 to comply with G.S. 62-133.7(b), (c), (d), (e) and (f);

(v) a comparison of actual compliance costs to the annual cost caps;

(vi) the status of compliance with the requirements of G.S. 62-133.7(b), (c), (d), (e) and (f);

(vii) the identification of any renewable energy certificates to be carried forward pursuant to G.S. 62-133.7(b)(2)f or (c)(2)f;

(viii) For each renewable energy facility providing renewable energy certificates used by the electric power supplier to comply with G.S. 62-133.7(b), (c), (d), (e) and (f): the name, address, and owner of the renewable energy facility; and an affidavit from the owner of the renewable energy facility certifying that the energy associated with the renewable energy certificates was derived from a renewable energy resource, identifying the renewable technology used, and listing the dates and amounts of all payments received from the electric power supplier and all meter readings; and

(ix) for electric membership corporations and municipal electric suppliers, reduced energy consumption achieved after January 1, 2008, through the implementation of a demand-side management program.

(2) Each electric public utility shall file its annual REPS compliance report no later than 30 days prior to the time that it files 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. 62-133.7(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 shall file an REPS compliance report on or before September 1 of each year. The Commission shall 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 additional 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. 62-133.7(b), (c), (d), (e) and (f) and fund research as provided in G.S. 62-133.7(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. 62-133.7(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. 62-133.7(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. 62-133.7(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. 62-133.7(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.

(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. 62-133.7(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. 62-133.7(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. 62-133.7(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. 62-133.7(b), (c), (d), (e) and (f).

(e) Cost recovery.

(1) For each electric public utility, the Commission shall schedule an annual public hearing pursuant to G.S. 62-133.7(h) to review the costs incurred by the electric public utility to comply with G.S. 62-133.7(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. 62-133.7(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 calendar year from its North Carolina retail customers to comply with G.S. 62-133.7(b), (d), (e) and (f) shall not exceed the per-account charges set forth in G.S. 62-133.7(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 may be collected through fixed monthly charges, energy-based amounts per kilowatt-hour, or by a combination of both. Each electric public utility shall ensure that the incremental costs recovered under the REPS rider and REPS EMF rider during the cost recovery period from any given customer account do not exceed the applicable per-account charges set forth in G.S. 62-133.7(h)(4).

(10) Incurred costs may be recovered by an electric public utility in any year after a renewable energy certificate is acquired or obtained until the renewable energy certificate is used to comply with G.S. 62-133.7(b), (d), (e) and (f) as long as the electric public utility's total annual incremental costs incurred in that year do not exceed the per-account annual charges provided in G.S. 62-133.7(h)(4). Incremental costs that exceed the per-account annual charges provided in G.S. 62-133.7(h)(4) in the year in which a renewable energy certificate is used to comply with G.S. 62-133.7(b), (d), (e) and (f) may not be recovered. 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. 62-133.7(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 certificates, 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.

(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 with a nameplate capacity of 1 MW or less interconnected behind the utility meter at a customer’s location may be measured accurately by an ANSI-certified electric meter not provided by an electric power supplier. The data provided by this meter may be read and self-reported by the owner of the renewable energy facility. The owner of the meter shall comply with the meter testing requirements of Rule R8-13.

(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 megawatt-hour for every 3,412,000 British thermal units of useful thermal energy produced.

(5) Except in those cases where the electric meter is supplied by and read by an electric power supplier, electric generation or thermal energy production data is subject to audit by the Commission, the Public Staff, or an electric power supplier.

Rule R8-68 is added as follows:

Rule 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. 62-133.8 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. 62-133.7(a) and G.S. 62-133.8(a).

(2) “Consideration” means anything of economic value paid, given or offered to any person by an electric public utility (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 utility; 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. 62-133.8.

(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. 62-133.8(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 proposed to be used, (e) the proposed classes of persons to whom it will be offered, and (f) the duration of the proposed measure or program.

(ii) Description. — The electric public utility or electric membership corporation shall describe each measure or program, including its duration, purpose, estimated number of participants, and the impact of 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.

(iii) 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 advertising) and the planned accounting treatment for those costs and benefits; (b) the type, amount, and 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.

(iv) 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.

(v) Communications. — The electric public utility or electric membership corporation shall provide detailed cost information on the amount it anticipates will be spent 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. To the extent available, the electric public utility or electric membership corporation shall include examples of all communication materials to be used in conjunction with the measure or program.

(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) Description. – The electric public utility shall describe:

a. the measure's objective;

b. total market potential;

c. the proposed marketing plan;

d. the targeted sector;

e. estimated market growth throughout the life of the measure;

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

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

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

i. estimated load shape impacts;

j. a description of market barriers to the proposed measure or program and how the electric public utility intends to address them;

k. a description of how the measure's impacts will be evaluated, measured, and verified; and

l. a description of 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.

(ii) 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. 62-133.8;

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; and

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. 62-133.8(d)(1).

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 (iii).

(iii) Measurement and Verification Reporting Plan for New Demand-Side Management and Energy Efficiency Measures. — The electric public utility shall describe the industry-accepted methods to be used to measure, verify, and validate the energy and peak demand savings estimated in paragraph (i) above and shall provide a schedule for reporting the savings to the Commission. 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. If the electric public utility plans to utilize an independent third party for purposes of measurement and verification, an identification of the third party and all of the costs of that third party should be included. The costs of implementing the measurement and verification process may be considered as operating costs.

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

(v) 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.

(vi) 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.

(d) Procedure.

(1) 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 or file a protest pursuant to Rule R1-6. The filing electric public utility or electric membership corporation shall have the opportunity to respond to the petitions or protests 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.

(2) 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. — Except for those costs found by the Commission to be unreasonable or imprudently incurred, the costs of new demand-side management or energy efficiency measures approved by application of this rule shall be recovered through the annual rider described in G.S. 62-133.8 and Rule R8-69. The Commission may also consider in the annual rider proceeding whether to approve any utility incentive pursuant to G.S. 62-133.8(d)(2)a-c.

Rule R8-69 is added as follows:

Rule 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. 62-133.7(a) and G.S. 62-133.8(a).

(2) "DSM/EE rider" means a charge or rate established by the Commission annually pursuant to G.S. 62-133.8(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. 62-133.8(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.

(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. 62-133.8.

(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. However, deferral accounting of costs shall not affect the Commission's authority under this rule to determine whether the deferred costs may be recovered.

(7) In approving the first annual rider pursuant to G.S. 62-133.8 for Duke Energy Carolinas, LLC, the Commission shall consider the treatment it approved in Docket No. E-7, Sub 828, of the revenues and costs related to Duke Energy Carolinas' existing demand-side management and energy efficiency measures or programs.

(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. 62-133.8(f), any industrial customer or large commercial customer may notify its electric power supplier that it has implemented or, in accordance with stated, quantifiable goals, will implement alternative demand-side management or energy efficiency measures. Any such customer may elect not to participate in new demand-side management and energy efficiency measures under G.S. 62-133.8(f). Any customer that elects this option and notifies its electric public utility will, after the date of notification, be exempt from any annual rider established pursuant to this rule.

(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.

(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 the 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. 62-133.8(d)(1). Within 30 days of the customer's election, the electric public utility shall notify the Commission of an industrial or large commercial customer that elects to participate in a new measure after having initially notified the electric public utility that it declined to participate.

(e) Annual Proceeding.

(1) For each electric public utility, the Commission shall schedule an annual rider hearing pursuant to G.S. 62-133.8(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. 62-133.8(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 capacity, energy, and measure unit metric and in the aggregate; and

e. total expected energy reduction in the aggregate and per appropriate capacity, energy and 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 per appropriate capacity, energy, and measure unit metric and in the aggregate, as well as any changes in estimated future amounts;

e. total energy reduction in the aggregate and per appropriate capacity, energy and 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 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. 62-133.8(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.

Chapter 8.
Appendix.

REVISED GUIDELINES FOR RESOLUTION OF ISSUES REGARDING INCENTIVE[10] PROGRAMS

1. To obtain Commission approval of a residential or commercial program involving incentives per Rule R1-38 [now Rule R6-95 or R8-68], the sponsoring utility must demonstrate that the program is cost effective for its ratepayers.

(a) Maximum incentive payments to any party must be capable of being determined from an examination of the applicable program.

(b) Existing approved programs are grandfathered. However, utilities shall file a listing of existing approved programs subject to these guidelines, including applicable tariff sheets, and amount and type of incentives involved in each program or procedure for calculating such incentives in each program, all within 60 days after approval of these guidelines.

(c) Utilities shall file a description of any new program or of a change in an existing program, including applicable tariff sheets, and amount and type of incentives involved in each program or procedure for calculating such incentives in each program, all at least 30 days prior to changing or introducing the program.

(d) The matter of the relative efficiency of electricity versus natural gas under various scenarios (space heating alone, space heating plus A/C, etc.) cannot now be resolved. A better approach at this time would be to determine the acceptability of incentive programs herein based on the energy efficiency of electricity alone or of natural gas alone, as applicable.

(e) The criteria for determining whether or not to approve an electric program pursuant to G.S. 62-140(c) should not include consideration of the impact of an electric program on the sales of natural gas, or vice versa.

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[10] All incentives referenced in these Revised Guidelines are participation incentives as now defined in Rule R8-68(b)(7).

(f) Approval of a program pursuant to Commission Rule R1-38 [now Rule R6-95 or R8-68] does not constitute approval of rate recovery of the costs of the program. The appropriateness of rate recovery shall be evaluated in general rate cases or similar proceedings.

2. If a program involves an incentive per Rule R1-38 [now Rule R6-95 or R8-68] and the incentive affects the decision to install or adopt natural gas service or electric service in the residential or commercial market, there shall be a rebuttable presumption that the program is promotional in nature.

(a) If the presumption that a program is promotional is not successfully rebutted, the cost of the incentive may not be recoverable from the ratepayers unless the Commission finds good cause to do so.

(b) If the presumption that a program is promotional is successfully rebutted, the cost of the incentive may be recoverable from the ratepayers. The cost shall not be disallowed in a future proceeding on the grounds that the program is primarily designed to compete with other energy suppliers. The amount of any recovery shall not exceed the difference between the cost of installing equipment and/or constructing a dwelling to current state/federal energy efficiency standards and the more stringent energy efficiency requirements of the program, to the extent found just and reasonable by the Commission.

(c) The presumption that a program is promotional may generally be rebutted at the time it is filed for approval by demonstrating that the incentive will encourage construction of dwellings and installation of appliances that are more energy efficient than required by state and/or federal building codes and appliance standards, subject to Commission approval.

3. If a program involves an incentive paid to a third party builder (residential or commercial), the builder shall be advised by the sponsoring utility that the builder may receive the incentive on a per structure basis without having to agree to: (a) a minimum number or percentage of all-gas or all-electric structures to be built in a given subdivision development or in total; or (b) the type of any given structure (gas or electric) to be built in a given subdivision development.

(a) Electric and gas utilities may continue to promote and pay incentives for all-electric and all-gas structures respectively, provided such programs are approved by the Commission.

(b) A builder shall be advised by the sponsoring utility of the availability of natural gas or electric alternatives, as appropriate.

(c) A builder receiving incentives shall not be required to advertise that the builder is exclusively an all-gas or all-electric builder for either a particular subdivision or in general.

4. The promotional literature for any program offering energy-efficiency mortgage discounts shall explain that the structures financed under the program need not be all-electric or all-gas.

5. Duke's proposed Food Service Program shall be modified to include a definition of qualifying equipment and of conventional equipment, and is subject to approval in accordance with guideline number 1 above.

(a) The nature or amount of incentive contained in each program encouraging the installation of commercial appliances (electric or gas) that use the sponsoring utility's energy product, such as Duke's Food Service Program, shall be unaffected by the availability or use of alternate fuels in the applicable customer's facility.

(b) Commercial clients (builders, customers, etc.) who are offered incentives for installation of appliances shall be advised by the sponsoring utility of the availability of natural gas or electric alternatives, as appropriate.

6. Rates, rate design issues, and terms and conditions of service approved by the Commission are not subject to these guidelines.

7. Pending applications involving incentive programs are subject to these guidelines.

Chapter 1.
Practice and Procedure.

Rule R1-37 is repealed.

Rule R1-38 is repealed.

Chapter 6.
Natural Gas.

Article 14.
Incentive programs.

Rule R6-95 is added as follows:

Rule R6-95. Incentive programs for natural gas utilities.

(a) Purpose. — The purpose of this rule is to establish guidelines for the application of G.S. 62-140(c) to natural gas utilities that are consistent with the directives of that statute and consistent with the public policy of this State set forth in G.S. 62-2.

(b) Definitions. — As used in this rule, the following definitions shall apply:

(1) “Consideration” means anything of economic value paid, given or offered to any person by a natural gas utility (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 natural gas utility–; 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.

(2) “Program” means any natural gas utility action or planned action that involves offering Consideration.

(3) “Person” means the same as defined in G.S. 62-3(21).

(4) “Natural gas utility” means, for purposes of this rule, a person, whether organized under the laws of this State or under the laws of any other state or country, that owns or operates in the State equipment

or facilities for producing, transporting, distributing, or furnishing piped gas to or for the public for consumption.

(c) Filing for Approval.

(1) Application of Rule. — Prior to a natural gas utility implementing any Program, the purpose or effect of which is to directly or indirectly alter or influence the decision to use the natural gas utility's service for a particular end-use or to directly or indirectly encourage the installation of equipment that uses the natural gas utility's service, the natural gas utility shall obtain Commission approval.

Whether a Program is offered at the expense of the natural gas utility's shareholders, ratepayers or a third party shall not affect the filing requirements under this rule.

A natural gas utility shall file for approval all Programs to offer Consideration which are administered, promoted or funded by the natural gas utility's subsidiaries, affiliates and/or unregulated divisions or businesses where the natural gas utility has control over the entity offering or is involved in the Program and an intent or effect of the Program is to adopt, secure, or increase the use of the natural gas utility's utility services.

(2) Filing Requirements. — Each application for the approval of a Program shall include the following:

(i) Cover Page. — The natural gas utility shall attach to the front of an application a cover sheet generally describing the Program, the Consideration to be offered, anticipated total cost of the Program, the source and amount of funding proposed to be used, proposed classes of persons to whom it will be offered, and the duration of the Program.

(ii) Description. — A detailed description of the Program, its duration, purpose, estimated number of participants, and impact on the natural gas utility's general body of customers and the natural gas utility.

(iii) Cost. — The estimated total and per unit cost for the Program to the natural gas utility, reported by type of expenditure (e.g., direct payment, rebate, advertising) and the planned accounting treatment for those costs. If the natural gas utility proposes to place any costs to be incurred in a deferred account for possible future recovery from its customers, it shall disclose the same and provide an estimate of each cost to be deferred. The natural gas utility shall describe, in detail, all other sources of monies to be used, including the name of the source, the amount provided, and the reasons the third party is providing the money.

(iv) Effect on Customer Use. — A statement of the effect, if any, that the Program is expected to have on customer use of the natural gas utility's service.

(v) Conditions of Program. — The type and amount of Consideration and how and to whom it will be offered or paid, including schedules listing the Consideration to be offered, a list of those who will use the natural gas utility's service, and other information on the availability and limitations (who can and cannot participate) of the Consideration. The natural gas utility shall describe any service limitations or conditions it imposes on customers who do not participate in the Program.

(vi) Economic Justification. — Economic justification for the Program, including the results of appropriate cost-effectiveness tests.

(vii) Communications. — Detailed cost information on the amount the natural gas utility anticipates will be spent on communication materials related to the Program. Such cost shall be included in the Commission's consideration of the total cost of the Program and whether the total cost of the Program is reasonable in light of the benefits. To the extent available, the natural gas utility shall include examples of all communication materials to be used in conjunction with the Program.

(viii) Commission Guidelines Regarding Incentive Programs. — The natural gas utility 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.

(ix) Other. — Any other information the natural gas utility believes relevant to the application, including information on competition faced by the natural gas utility.

(d) Procedure.

(1) Service and Response. — The natural gas utility filing for approval of a Program shall serve a copy of its filing on the electric utilities and electric membership corporations operating within the filing natural gas utility's certificated territory, the Public Staff, the Attorney General and any other party that has notified the natural gas utility in writing that it wishes to be served with copies of all such filings that involve the provision of Consideration. Those served, and others learning of the application, shall have thirty (30) days from the date of filing in which to seek intervention pursuant to ~~Commission~~ Rule R1-19 or file a protest pursuant to ~~Commission~~ Rule R1-6. The filing natural gas utility shall have the opportunity to respond to such petitions or protests within ten (10) days of their filing. If any party granted intervention requests a hearing or otherwise raises a material issue of fact, the Commission may, in its discretion, set the matter for hearing.

(2) Notice and Schedule. — If the application is set for hearing, the Commission shall require such notice as it deems 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 considering whether to approve in whole or in part a Program or changes to an existing Program, the Commission may consider any other information it determines to be relevant, including, but not limited to, the following issues:

(1) Whether the Program unreasonably discriminates among persons receiving or applying for the same kind and degree of service;

(2) Evidence of consideration or compensation paid by any competitor, regulated or unregulated, of the natural gas utility to secure the installation or adoption of the use of such competitor's services;

(3) Whether the 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

(4) Whether the Program encourages energy efficiency and its impact on the peak loads and load factors of the filing natural gas utility.

Chapter 8.
Electric Light and Power.

Article 10.
Fuel Based Rate Changes.

Rule R8-52 is rewritten as follows:

Rule R8-52. Monthly fuel report.

(a) On or before the 15th day of each month, each electric public utility which uses fossil and/or nuclear fuel in the generation of electric power for providing North Carolina retail electric service shall file a Fuel Report for the second preceding month (i.e., up to 45 days after the end of the month being reported) for review by the Commission, the Public Staff, and any other interested party. ~~(1)~~ The Monthly Fuel Report shall be filed in such formats as shall from time to time be approved by the Commission, and ~~said reports~~ shall include the following information:

(~~i~~1) Details of power plant performance and generation;

(~~ii~~2) Details of cost of fuel burned~~and fuel-related costs as defined in G.S. 62-133.2~~;

(3) Details of cost of fuel transportation;

(4) Details of fuel consumption and inventories;

(5) Analysis of fossil fuel purchases;

(6) Details of cost and inventories of ammonia, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions;

(~~iii~~7) Details of transactions for purchases, sales, and interchanges of power, including (i) total delivered noncapacity related costs of purchases that are subject to economic dispatch or economic curtailment and (ii) capacity costs associated with purchases from qualifying cogeneration facilities and qualifying small power production facilities, as defined in 16 U.S.C. 796, that are subject to economic dispatch;

~~(iv) Details of fuel and fuel-related consumption and inventories; and~~

~~(v) Analysis of fossil fuel purchases.~~

(8) Details of the total delivered costs of purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.7 and costs incurred to comply with any federal mandate that is similar to subsections (b), (d), (e), and (f) of G.S. 62-133.7;

(9) Details of the fuel cost component of other purchased power;

(10) Details of net gains or losses resulting from sales of fuel or other fuel-related costs components as defined in G.S. 62-133.2(a1);

(11) Details of net gains or losses resulting from sales of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs as defined in G.S. 62-133.2(a1); and

(12) Details of costs incurred to comply with the Swine Farm Methane Capture Pilot Program established in Section 4 of S.L. 2007-523.

Subdivisions (6) and (7)(ii) of this subsection do not apply to the Monthly Fuel Report of an electric public utility that is subject to G.S. 62-133.2(a3).

(b) Each electric public utility which uses fossil and/or nuclear fuel in the generation of electric power shall file a Fuel Procurement Practices Report for review by the Commission at least once every ten (10) years, plus each time the utility's fuel procurement practices change. The Fuel Procurement Practices Report shall detail:

(1) The process and/or methodology the utility uses to determine its fuel and fuel-related needs;

(2) The process the utility uses to determine from which vendor it shall buy fuel and fuel-related inventories; and

(3) The inventory management practices the utility follows to maintain its fuel and fuel-related inventories.

Rule R8-55 is rewritten as follows:

Rule R8-55. Annual hearings to review changes in the cost of fuel and fuel-related costs.

(a) As used in this rule, "cost of fuel and fuel-related costs" means all of the following:

(1) The cost of fuel burned.

(2) The cost of fuel transportation.

(3) The cost of ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions.

(4) The total delivered noncapacity related costs, including all related transmission charges, of all purchases of electric power by the electric public utility~~,~~ that are subject to economic dispatch or economic curtailment.

(5) The capacity costs associated with all purchases of electric power from qualifying cogeneration facilities and qualifying small power production facilities, as defined in 16 U.S.C. ~~§~~ 796, that are subject to economic dispatch by the electric public utility.

(6) Except for those costs recovered pursuant to G.S. 62-133.7(h), the total delivered costs of all purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.7 or to comply with any federal mandate that is similar to the requirements of subsections (b), ~~(c),~~ (d), (e) and (f) of G.S. 62-133.7.

(7) All costs ~~of compliance~~ incurred to comply with the Swine Farm Methane Capture Pilot Program ~~pursuant to North Carolina Session Law~~ established in Section 4 of S.L. 2007-523 ~~(Senate Bill 1465)~~.

(8) The fuel cost component of other purchased power.

Cost of fuel and fuel-related costs shall be adjusted for (a) any net gains or losses resulting from any sales by the electric public utility of fuel and other fuel-related costs components and (b) any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs.

(b) For each electric public utility generating electric power by means of fossil and/or nuclear fuel for the purpose of furnishing North Carolina retail electric service, the Commission shall schedule an annual public hearing pursuant to G.S. 62-133.2(b) in order to review changes in the electric public utility's cost of fuel and fuel-related costs. The annual cost of fuel and fuel-related cost adjustment hearing for ~~Duke Power Company LLC, d/b/a~~ Duke Energy Carolinas, LLC, will be scheduled for the ~~third~~ first Tuesday of June each year;

for Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., the annual hearing will be scheduled for the third Tuesday of September each year; and for Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, the annual hearing will be scheduled for the second Tuesday of ~~December~~ November each year.

(c) The test periods for the hearings to be held pursuant to paragraph (b) above will be uniform over time. The test period for Duke Energy Carolinas, LLC will be the calendar year; for Progress Energy Carolinas, Inc., the test period will be the 12-month period ending March 31; and for Dominion North Carolina Power, the test period will be the 12-month period ending June 30.

(d) The Commission shall permit each electric public utility to charge an increment or decrement as a rider to its rates for changes in the cost of fuel and fuel-related costs used in providing its North Carolina customers with electricity from the cost of fuel and fuel-related costs established in the electric public utility's previous general rate case on the basis of cost per kilowatt-hour. The increment or decrement may be different among customer classes. The general methodology and procedures to be used in establishing the cost of fuel and fuel-related costs~~,~~ shall be as follows:

(1) Cost of ~~F~~fuel and fuel-related costs will be preliminarily established utilizing the methods and procedures approved in the utility's last general rate case, except that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability ~~Council's Equipment~~ Corporation's Generating Availability Report, adjusted to reflect unique, inherent characteristics of the utility, including, but not limited to, plants 2 years or less in age and unusual events. The national average capacity factor for nuclear production facilities shall be based on the most recent 5-year period available and shall be weighted, if appropriate, for both pressurized water reactors and boiling water reactors. The costs shall be allocated among customer classes in accordance with G.S. 62-133.2(a2), as applicable. A cost of fuel and fuel-related cost rider will then be determined based upon the difference between the cost of fuel and fuel-related costs thus established and the base cost of fuel and fuel-related cost component of the rates established in the utility's most recent general rate case. The foregoing normalization requirement assumes that the Commission finds that an abnormality having a probable impact on the utility's revenues and expenses existed during the test period.

(2) Cost of fuel and fuel-related costs will be modified as provided in G.S. 62-133.2(a3).

(~~2~~3) The cost of fuel and fuel-related costs as described above will be further modified through use of an experience modification factor (EMF) rider, which may be different among customer classes. The EMF rider will reflect the difference between reasonable and prudently incurred cost of fuel and fuel-related costs and the fuel-related revenues that were actually realized during the test period under the cost of fuel and fuel-related cost components of rates 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 cost of fuel and fuel-related costs ~~through the date that is~~ up to thirty (30) ~~calendar~~ 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 fuel and fuel-related costs adjustment hearing.

(~~3~~4) The cost of fuel and fuel-related cost rider and the EMF rider as described hereinabove will be charged as an increment or decrement to the base fuel cost component of rates established in the electric public utility's previous general rate case.

(~~4~~5) The 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; provided, however, that such carry-through provision will not relieve the Commission of its responsibility to determine the reasonableness of the cost of fuel and fuel-related costs, other than that being collected through operation of the EMF rider, in any intervening general rate case proceeding.

(~~5~~6) Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred cost of fuel and fuel-related costs to be refunded to a utility's customers through operation of the 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.

(e) Each electric public utility, at a minimum, shall submit to the Commission for purposes of investigation and hearing the information and data in the form and detail as set forth below:

(1) Actual test period kWh sales, peak demand by customer class, fuel-related revenues, and fuel-related expenses for the utility's total system and for its North Carolina retail operations.

(2) Test period kWh sales normalized for weather, customer growth and usage. Said normalized kWh sales shall be for the utility's total system and for its North Carolina retail operations. The methodology used for such normalization shall be the same methodology adopted by the Commission, if any, in the utility's last general rate case.

(3) Adjusted test period kWh generation corresponding to normalized test period kWh usage. The methodology for such adjustment shall be the same methodology adopted by the Commission in the utility's last general rate case, including adjustment by type of generation; i.e., nuclear, fossil, hydro, pumped storage, purchased power, etc. In the event that said methodology is inconsistent with the normalization methodology set forth in paragraph (d)(1) above, additional pro forma

calculations shall be presented incorporating the normalization methodology reflected in paragraph (d)(1).

(4) Cost of fuel and applicable fuel-related costs corresponding to the adjusted test period kWh generation, including a detailed explanation showing how such cost of fuel and fuel-related costs were derived. The cost of fuel shall be based on end-of-period unit fuel prices incurred during the test period, although the Commission may consider other fuel prices if test period fuel prices are demonstrated to be nonrepresentative on an on-going basis. Unit fuel prices shall include delivered fuel prices and burned fuel expense rates as appropriate.

(5) Procurement practices and inventories for~~:~~ fuel burned and for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions.

(6) The cost ~~incurred at each generating facility~~ of fuel burned and of ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions at each generating facility.

(7) Any net gains or losses resulting from any sales by the electric public utility of fuel or other fuel-related costs components.

(8) Any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs.

(9) All costs ~~of compliance~~ incurred to comply with the Swine Farm Methane Capture Pilot Program ~~pursuant to North Carolina session Law~~ established in Section 4 of S.L. 2007-523 ~~(Senate Bill 1465)~~.

(10) The monthly fuel report and the monthly base load power plant performance report for the last month in the test period and any information required by ~~NCUC~~ Rules R8-52 and R8-53 for the test period which has not already been filed with the Commission. Further, such information for the complete 12-month test period shall be provided by the electric public utility to any intervenor upon request.

(11) All workpapers supporting the calculations, adjustments and normalizations described above.

(12) The nuclear capacity rating(s) in the last rate case and the rating(s) proposed in this proceeding. If they differ, supporting justification for the change in nuclear capacity rating(s) since the last rate case.

(13) The proposed rate design to recover the electric public utility's cost of fuel and fuel-related costs.

An electric public utility that is subject to G.S. 62-133.2(a3) is required to provide only the applicable information prescribed by subdivisions (5), (6) and (8) of this subsection.

(f) ~~Each~~ The electric public utilit~~ies~~y shall file the information required under this rule, accompanied by workpapers and direct testimony and exhibits of expert witnesses supporting the information filed herein, and any changes in rates proposed by the electric public utility (if any), according to the following schedule: Duke Energy Carolinas, LLC, and Progress Energy Carolinas, Inc., not less than 90 days prior to the hearing; Dominion North Carolina Power, not less than 75 ~~at least 105~~ days prior to the hearing. Nothing in this rule shall be construed to require the electric public utility to propose a change in rates or to utilize any particular methodology to calculate any change in rates proposed by the utility in this proceeding.

(g) The electric public utility shall publish a notice for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least 30 days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-133.2(b) and setting forth the time and place of the hearing.

(h) 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.

(i) 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.

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

(k) The burden of proof as to the correctness and reasonableness of any charge and as to whether the test year cost of fuel and fuel-related costs ~~expenses~~ were reasonable and prudently incurred shall be on the utility. For purposes of determining the EMF rider, a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability ~~Council's Equipment~~ Corporation's Generating Availability Report, appropriately weighted for size and type of plant or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent North American Electric Reliability ~~Council's Equipment~~ Corporation's Generating Availability Report, appropriately weighted for size and type of plant, or a presumption will be created that the utility incurred the increased cost of fuel and fuel-related costs ~~expense~~ resulting therefrom imprudently and that disallowance thereof is appropriate. The utility shall have the opportunity to rebut this presumption at the hearing and to prove that its test year cost of fuel and fuel-related costs were reasonable and prudently incurred. To the extent that the utility rebuts the presumption by the preponderance of the evidence, no disallowance will result.

(l) The hearing will generally be held in the Hearing Room of the Commission at its offices in Raleigh, North Carolina.

(~~n~~m) Each electric public utility shall follow deferred accounting with respect to the difference between actual reasonable and prudently incurred cost of fuel and fuel-related costs and cost of fuel and fuel-related ~~revenues realized~~ costs recovered under rates in effect.

(~~m~~n) If the Commission has not issued an order pursuant to G.S. 62-133.2 within 180 days after the date the electric public utility has filed any proposed changes in its rates and charges in this proceeding based solely on the cost of fuel and ~~the~~ fuel-related costs, then ~~said~~ the utility may place such proposed changes into effect. If such changes in the rates and charges are finally determined to be excessive, ~~said~~ the electric public utility shall refund any excess plus interest to its customers in a manner directed by the Commission.

Article 11.
Resource Planning and Certification.

Rule R8-60 is rewritten as follows:

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 Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; Virginia Electric and Power Company, d/b/a Dominion North Carolina Power; the North Carolina Electric Membership Corporation; and any individual electric membership corporation to the extent that it is responsible for procurement of any or all of its individual power supply resources.

(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);~~, and~~ 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. 62-133.8(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. 62-133.7.

(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, ~~renewable energy resources such as~~ 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-~~s~~Side Resources, and Demand-~~s~~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 (MW~~H~~h) 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:

(~~A~~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; ~~and~~

(~~B~~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

(~~C~~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):

(~~A~~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:

~~i~~a. Type of fuel(s) used;

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

~~iii~~c. Location of each existing unit;

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

~~v~~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

~~vi~~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.

(~~B~~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:

~~i~~a. Type of fuel(s) used;

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

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

~~iv~~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.

(~~C~~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 ~~their~~ 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.

(~~A~~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.

(~~B~~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.

(~~C~~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-~~s~~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.

(~~A~~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.

(~~B~~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.

(~~C~~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.

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

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

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

(~~A~~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.

(~~B~~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. — Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Duke Energy Carolinas, LLC; and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power shall provide information on levelized busbar costs for various generation technologies.

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

Rule R8-61 is rewritten as follows:

Rule R8-61. Preliminary plans and certificates of public convenience and necessity for construction of electric generation and related transmission facilities in North Carolina; construction of out-of-state electric generating facilities; progress reports and ongoing reviews of construction; project development cost reviews for nuclear generating facilities.

(a) Information to be filed 120 or more days before the filing of an application, by a public utility or other person, for a certificate of public convenience and necessity for generating facilities with capacity of 300 MW or more shall include the following:

(1) Available site information (including maps and description), preliminary estimates of initial and ultimate development, justification for the adoption of the site selected, and general information describing the other locations considered;

(2) As appropriate, preliminary information concerning geological, aesthetic, ecological, meteorological, seismic, water supply, population and general load center data to the extent known;

(3) A statement of the need for the facility, including information on loads and generating capability;

(4) A description of investigations completed, in progress, or proposed involving the subject site;

(5) A statement of existing or proposed plans known to the applicant of federal, state, local governmental and private entities for other developments at or adjacent to the proposed site;

(6) A statement of existing or proposed environmental evaluation programs to meet the applicable air and water quality standards;

(7) A brief general description of practicable transmission line routes emanating from the site;

(8) A list of all agencies from which approvals will be sought covering various aspects of any generation facility constructed on the site and the title and nature of such approvals~~.~~;

(9) A statement of estimated cost information, including plans and related transmission capital cost (initial core costs for nuclear units); all operating expenses by categories, including fuel costs and total generating cost per net kWh at plant; and information concerning capacity factor, heat rate, and plant service life. Furnish comparative cost including related transmission cost of other final alternatives considered; and

(10) A schedule showing the anticipated beginning dates for construction, testing, and commercial operation of the generating facility.

(b) In filing an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) in order to construct a generating facility in North Carolina, a public utility shall include the following information supported by relevant testimony:

(1) The most recent biennial report and the most recent annual report (as defined in Rule R8-60) of the utility plus any proposals by the utility to update said report;

(2) The extent to which the proposed construction conforms to the utility's most recent biennial report and the most recent annual report (as defined in Rule R8-60);

(3) Support for any utility proposals to update its most recent biennial report and its most recent annual report (as defined in Rule R8-60);

(4) Updates, if any, to the Rule R8-61(a) information;

(5) An estimate of the construction costs for the generating facility;

(6) The projected cost of each major component of the generating facility and the projected schedule for incurring those costs;

(7) The projected effect of investment in the generating facility on the utility's overall revenue requirement for each year during the construction period;

(8) The anticipated construction schedule for the generating facility;

(9) ~~Information which identifies t~~The specific type of units selected for the generating facility; the suppliers of the major components of the facility;~~ and~~ the basis for selecting the type of units, major components, and suppliers; and the adequacy of fuel supply;

(10) ~~Information which details t~~The qualifications and selection of principal contractors and suppliers for construction of the generating facility, other than those listed in Item (9) above;

(11) ~~Information regarding r~~Resource and fuel diversity and reasonably anticipated future operating costs, including the anticipated in-service expenses associated with the generating facility for the 12-month period of time following commencement of commercial operation of the facility;

(12) ~~Information which identifies r~~Risk factors related to the construction and operation of the generating facility; and

(13) If the application is for a coal or nuclear generating facility, information ~~showing~~ demonstrating that energy efficiency measures; demand-side management; renewable energy resource generation; combined heat and power generation; or any combination thereof, would not establish or maintain a more cost-effective and reliable generation

system and that the construction and operation of the facility is in the public interest.

(c) The public utility shall submit a progress report and any revision in the construction cost estimate during each year of construction according to a schedule ~~ordered~~ established by the Commission.

(d) Upon the request of the public utility or upon the Commission's own motion, the Commission may conduct an ongoing review of construction of the generating facility as the construction proceeds.

(e) A public utility requesting an ongoing review of construction of the generating facility pursuant to G.S. 62-110.1(f) shall file an application, supported by relevant testimony, for an ongoing review no later than 12 months after the date of issuance of a certificate of public convenience and necessity by the Commission; provided, however, that the public utility may, prior to the conclusion of such 12-month period, petition the Commission for a reasonable extension of time to file an application based on a showing of good cause. Upon the filing of a request for an ongoing review, the Commission shall establish a schedule of hearings. ~~Such~~ The hearings shall be held no more often than every 12 months. The Commission shall also establish the time period to be reviewed during each hearing. The purpose of each ongoing review hearing is to determine the reasonableness and prudence of the costs incurred by the public utility during the period under review and to determine whether the certificate should remain in effect or be modified or revoked. The public utility shall have the burden of proof to demonstrate that all costs incurred are reasonable and prudent.

(f) A public utility may file an application pursuant to G.S. 62-110.6 requesting the Commission to ~~make a~~ determine~~ation of~~ the need for an out-of-state electric generating facility that is intended to serve retail customers in North Carolina. If need for the generating facility is established, the Commission shall also approve an estimate of the construction costs and construction schedule for such facility. ~~Such~~ The application ~~shall~~ may be filed ~~no later than 6 months~~ at any time after an application for a certificate of public convenience and necessity or license for construction of the generating facility has been filed in the state in which the facility will be sited. The application shall be supported by relevant testimony and shall ~~generally~~ include the information required by subsection (b) of this Rule to the extent such information is relevant to the showing of need for the generating facility and the estimated construction costs and proposed construction schedule for the generating facility~~, supported by relevant testimony~~. The public utility shall submit a progress report and any revision in the construction cost estimate for the out-of-state electric generating facility during each year of construction according to a schedule ~~ordered~~ established by the Commission.

(g) If the Commission makes a determination of need pursuant to G.S. 62-110.6 and subsection (f) of this Rule, the provisions of subsections (d) and (e) of this Rule shall apply to a request by a public utility for an ongoing review of construction of a generating facility to be constructed in another state that is intended to serve retail customers in North Carolina. An electric public utility shall file an application, supported by relevant testimony, for an ongoing review no later than 12 months after the date of issuance of a certificate of public convenience and necessity or license by the state commission in which the out-of-state generating facility is to be constructed; provided, however, that the public utility may, prior to the conclusion of such 12-month period, petition the Commission for a reasonable extension of time to file an application based on a showing of good cause.

(h) A public utility may file an application pursuant to G.S. 62-110.7 requesting the Commission to review ~~a~~ the public utility's decision to incur project development costs for a potential in-state or out-of-state nuclear generating facility that is intended to serve retail electric customers in North Carolina. ~~Any such~~ The application, supported by relevant testimony, shall be filed ~~before any project development costs are actually incurred~~ prior to the filing of an application for a certificate to construct the facility.

Rule R8-64 is added as follows:

Rule R8-64. Application for certificate of public convenience and necessity by qualifying cogenerator or small power producer; progress reports.

(a) Scope of Rule.

(1) This rule applies to applications for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) filed by any person seeking the benefits of 16 U.S.C.~~A.~~ 824a-3 or G.S. 62-156 as a qualifying cogenerator or a qualifying small power producer as defined in 16 U.S.C.~~A.~~ 796(17) and (18) or as a small power producer as defined in G.S. 62-3(27a), except persons exempt from certification by the provisions of G.S. 62-110.1(g).

(2) For purposes of this rule, the term "person" shall include a municipality as defined in Rules R7-2(c) and R10-2(c), including a county of the State.

(3) The construction of a facility for the generation of electricity shall include not only the building of a new building, structure or generator, but also the renovation or reworking of an existing building, structure or generator in order to enable it to operate as a generating facility.

(4) This rule shall apply to any person within its scope who begins construction of an electric generating facility without first obtaining a certificate of public convenience and necessity. In such circumstances, the application shall include an explanation for the applicant's beginning of construction before the obtaining of the certificate.

(b) The Application.

(1) The application shall be accompanied by maps, plans, and specifications setting forth such details and dimensions as the Commission requires. It shall contain, among other things, the following information, either embodied in the application or attached thereto as exhibits:

(i) The full and correct name, business address and business telephone number of the applicant;

(ii) A statement of whether the applicant is an individual, a partnership, or a corporation and, if a partnership, the name and business address of each general partner and, if a corporation, the state and date of incorporation and the name and business address of an individual duly authorized to act as corporate agent for the purpose of the application and, if a foreign corporation, whether domesticated in North Carolina;

(iii) The nature of the generating facility, including the type and source of its power or fuel;

(iv) The location of the generating facility set forth in terms of local highways, streets, rivers, streams, or other generally known local landmarks together with a map, such as a county road map, with the location indicated on the map;

(v) The ownership of the site and, if the owner is other than the applicant, the applicant's interest in the site;

(vi) A description of the buildings, structures and equipment comprising the generating facility and the manner of its operation;

(vii) The projected maximum dependable capacity of the facility in megawatts;

(viii) The projected cost of the facility;

(ix) The projected date on which the facility will come on line;

(x) The applicant's general plan for sale of the electricity to be generated, including the utility to which the applicant plans to sell the electricity; any provisions for wheeling of the electricity; arrangements for firm, non-firm or emergency generation; the service life of the project; and the projected annual sales in kilowatt-hours; and

(xi) A complete list of all federal and state licenses, permits and exemptions required for construction and operation of the generating facility and a statement of whether each has been obtained or applied for. A copy of those that have been obtained should be filed with the application; a copy of those that have not been obtained at the time of the application should be filed with the Commission as soon as they are obtained.

(2) In addition to the information required above, an applicant who desires to enter into a contract for a term of 5 years or more for the sale of electricity and who will have a projected ~~maximum~~ dependable capacity of 5 megawatts or more available for such sale shall include in the application the following information and exhibits:

(i) A statement detailing the experience and expertise of the persons who will develop, design, construct and operate the project to the extent such persons are known at the time of the application;

(ii) Information specifically identifying the extent to which any regulated utility will be involved in the actual operation of the project;

(iii) A statement obtained by the applicant from the electric utility to which the applicant plans to sell the electricity to be generated setting forth an assessment of the impact of such purchased power on the utility's capacity, reserves, generation mix, capacity expansion plan, and avoided costs;

(iv) The most current available balance sheet of the applicant;

(v) The most current available income statement of the applicant;

(vi) An economic feasibility study of the project;

(vii) A statement of the actual financing arrangements entered into in connection with the project to the extent known at the time of the application;

(viii) A detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year;

(ix) A detailed explanation of all energy inputs and outputs, of whatever form, for the project, including the amount of energy and the form of energy to be sold to each purchaser; and

(x) A detailed explanation of arrangements for fuel supply, including the length of time covered by the arrangements, to the extent known at the time of the application.

(3) All applications shall be signed and verified by the applicant or by an individual duly authorized to act on behalf of the applicant for the purpose of the application.

(4) Applications ~~are exempt from Rule R1-5(d), which requires that pleadings~~ filed on behalf of a corporation are not subject to the provision of R1-5(d) that requires corporate pleadings to be filed by a member of the Bar of the State of North Carolina. Should a public hearing be required, the requirements of G.S. 84-4 and G.S. 84-4.1 ~~are still~~ shall be applicable.

(5) Falsification of or failure to disclose any required information in the application may be grounds for ~~denial~~ denying or ~~revocation of~~ revoking any certificate.

(6) The application and ~~19~~ 30 copies shall be filed with the Chief Clerk of the Utilities Commission.

(c) Procedure upon receipt of Application. — Upon the filing of an application appearing to meet the requirements set forth above, the Commission will process it as follows:

(1) The Commission will issue an order requiring the applicant to publish notice of the application once a week for four successive weeks in a daily newspaper of general circulation in the county where the generating facility is proposed to be constructed and requiring the applicant to mail a copy of the application and the notice, no later than the first date that such notice is published, to the electric utility to which the applicant plans to sell the electricity to be generated. The applicant shall be responsible for filing with the Commission an affidavit of publication and a signed and verified certificate of service to the effect that the application and notice have been mailed to the electric utility to which the applicant plans to sell the electricity to be generated.

(2) The Chief Clerk will deliver ~~10~~ 16 copies of the application and the notice to the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration for distribution by the Coordinator to State agencies having an interest in the application.

(3) If a complaint is received within 10 days after the last date of the publication of the notice, the Commission will schedule a public hearing to determine whether a certificate should be awarded and will give reasonable notice of the time and place of the hearing to the applicant and to each complaining party and will require the applicant to publish notice of the hearing in the newspaper in which the notice of the application was published. If no complaint is received within the time specified, the Commission may, upon its own initiative, order and schedule a hearing to determine whether a certificate should be awarded and, if the Commission orders a hearing upon its own initiative, it will require notice of the hearing to be published by the applicant in the newspaper in which the notice of the application was published.

(4) If no complaint is received within the time specified and the Commission does not order a hearing upon its own initiative, the Commission will enter an order awarding the certificate.

(d) The Certificate.

(1) The certificate shall be subject to revocation if any of the other federal or state licenses, permits or exemptions required for construction and operation of the generating facility is not obtained and that fact is brought to the attention of the Commission and the

Commission finds that as a result the public convenience and necessity no longer requires, or will require, construction of the facility.

(2) The certificate must be renewed by re-compliance with the requirements set forth in this Rule if the applicant does not begin construction within 5 years after issuance of the certificate.

(3) Both before the time construction is completed and after, all certificate holders must advise both the Commission and the utility involved of any plans to sell, transfer, or assign the certificate or the generating facility or of any significant changes in the information set forth in subsection (b)(1) of this Rule, and the Commission will order such proceedings as it deems appropriate to deal with such plans or changes.

(e) Reporting. — All applicants must submit annual progress reports ~~as required by G.S. 62-110.1(f)~~ until construction is completed.

Rule R8-65 is added as follows:

Rule R8-65. Report by persons constructing electric generating facilities exempt from certification requirement.

(a) All persons exempt from certification ~~by the provisions of~~ under G.S. 62-110.1(g) shall file with the Commission a report of the proposed construction of an electric generating facility before beginning construction ~~thereof~~of the facility.

~~(b) The Application.~~

~~(1) Each~~ The report of proposed construction shall include the information ~~set forth~~ prescribed in subsection (b)(1) of Rule R8-64~~.~~ and

~~(2) Each report of construction~~ shall be signed and verified by the owner of the electric generating facility or by an individual duly authorized to act on behalf of the owner for the purpose of the filing.

(~~3~~b) Reports ~~of construction are not subject to Rule R1-5(d), which requires that pleadings~~ filed on behalf of a corporation are not subject to the provision of Rule R1-5(d) that requires corporate pleadings to be filed by a member of the Bar of the State of North Carolina. Should a public hearing be required, the requirements of G.S. 84-4 and G.S. 84-4.1 shall be applicable.

(~~4~~c) The owner of the electric generating facility shall provide a copy of the report of proposed construction to the electric public utility, electric membership corporation, or municipality to which the generating facility will be interconnected.

(~~5~~d) The owner of the electric generating facility shall file an original and ~~19~~ 30 copies of the report of proposed construction with the Chief Clerk of the Utilities Commission.

~~(6)~~ No filing fee is required ~~to be submitted with the report of construction~~.

~~(c) Procedure upon receipt of Application.~~

(~~1~~e) Upon ~~receipt~~ the filing of a report of proposed construction, the Chief Clerk will assign a new docket or sub-docket number to the filing~~.~~ and

~~(2) The Chief Clerk~~ will deliver ~~10~~ 16 copies of the report of proposed construction to the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration for distribution by the Coordinator to State agencies having an interest in the filing for information only.

(~~3~~f) The Commission may order a hearing on the report of proposed construction upon its own motion or upon receipt of a complaint~~;~~ specifying the basis thereof. ~~o~~Otherwise, no acknowledgment of receipt of the report of proposed construction will be issued nor will any other further action be taken by the Commission.

Rule R8-66 is added as follows:

Rule R8-66. Registration of renewable energy facilities; annual reporting requirements.

(a) The following terms shall be defined as provided in G.S. 62-133.7: “electric power supplier”; “renewable energy certificate”; and “renewable energy facility.”~~.~~

(b) The owner, including an electric power supplier, of each renewable energy facility, whether or not required to obtain a certificate of public convenience and necessity pursuant to G.S. 62-110.1, that intends ~~to sell electric power or~~ for renewable energy certificates it earns to be eligible for use by an electric power supplier ~~pursuant~~ to comply with G.S. 62-133.7~~(b)(2) or (c)(2)~~ shall ~~first~~ register with the Commission. The registration statement may be filed separately or together with an application for a certificate of public convenience and necessity, ~~or~~ with a report of proposed construction by a person exempt from the certification requirement, or by an electric power supplier with a compliance plan under Rule R8-67(b) if the facility is owned by the electric power supplier or under contract to the electric power supplier as of the effective date of this rule. All relevant renewable energy facilities shall be registered prior to the electric power supplier filing its REPS compliance report pursuant to Rule R8-67(c). Contracts for power supplied by an agency of the federal government are exempt from the requirement to register and file annually with the Commission if the renewable energy certificates associated with the power are bundled with the power purchased by the electric power supplier.

(1) The owner of each renewable energy facility that has not previously done so, including a facility that is located outside of the State

of North Carolina, shall include in its registration statement the information set forth in paragraphs (i) through (v) and paragraph (xi) of subsection (b)(1) of Rule R8-64, a description of the technology used to produce electricity, and the facility's projected dependable capacity in megawatts by generating unit. If the facility is not yet completed and in operation, the owner shall also file the information prescribed in paragraph (ix) of subsection (b)(1) of Rule R8-64.

(2) The owner of each renewable energy facility required to file Form EIA-~~860~~923 with the Energy Information Administration (EIA), United States Department of Energy, shall include with its registration statement a copy of Schedules 1, 5, 6 and 9 from its most recent Form EIA-~~860~~923 and shall file a copy of those Schedules with the Commission each year at the same time the information is provided to the EIA. The owner of a renewable energy facility that is not required to file Form EIA-923 with the EIA shall nevertheless file the information required by Schedules 1, 5, 6 and 9 with its registration statement and by April 1st of each year thereafter.

(3) The owner of each renewable energy facility shall certify in its registration statement and annually thereafter that it is in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources. If a credible showing is made that the facility is not in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources, the Commission shall refer the matter to the appropriate environmental agency for review. Provided, however, that once issued, a registration shall not be revoked unless and until the appropriate environmental agency concludes that the facility is out of compliance and the Commission revokes the registration.

(4) The owner of each renewable energy facility shall certify in its registration statement and annually thereafter that the facility satisfies the requirements of G.S. 62-133.7(a)(5) or (7), that the facility will be operated as a renewable energy facility and, if the facility has been placed into service, the date when it was placed into service.

(5) The owner of each renewable energy facility shall further certify in its registration statement and annually thereafter that any renewable energy certificates (whether or not bundled with ~~the purchase of~~ electric power) sold to an electric power supplier ~~for the purpose of compliance~~ to comply with G.S. 62-133.7 have not, and will not, be remarketed or otherwise resold for any other purpose, including another renewable energy portfolio standard or voluntary purchase of renewable energy ~~purchase program~~ certificates in North Carolina or any other state or country, and that the electric power associated with the certificates will not be offered or sold with any representation that the power is bundled with renewable energy certificates. The owner shall also annually report whether it sold any renewable energy certificates (whether or not bundled

with electric power) during the prior year and, if so, how many and to whom.

(6) The owner of each renewable energy facility shall certify in its registration statement and annually thereafter that it consents to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers, and agrees to provide the Public Staff and the Commission access to its books and records, wherever they are located, and to the facility.

(~~5~~7) Each registration statement shall be signed and verified by the owner of the renewable energy facility or by an individual duly authorized to act on behalf of the owner for the purpose of the filing.

(~~6~~8) Registration statements filed on behalf of a corporation are not subject to the provision of Rule R1-5(d)~~, which~~ that requires ~~that~~ corporate pleadings ~~filed on behalf of a corporation~~ to be filed by a member of the Bar of the State of North Carolina. Should a public hearing be required, the requirements of G.S. 84-4 and G.S. 84-4.1 shall be applicable.

(~~7~~9) ~~The owner of the renewable energy facility shall file a~~An original and ~~19~~ 30 copies of the registration statement shall be filed with the Chief Clerk of the Utilities Commission.

~~(8)~~ No filing fee is required to be submitted with the registration statement.

(c) Each re-seller of renewable energy certificates derived from a renewable energy facility, including a facility that is located outside of the State of North Carolina, shall ensure that the owner of the renewable energy facility registers with the Commission prior to the sale of the certificates by the re-seller to an electric power supplier to comply with G.S. 62 133.7(b), (c), (d), (e) and (f), except that the filing requirements in subsection (b) of this Rule shall apply only to information for the year(s) corresponding to the year(s) in which the certificates to be sold were earned.

(~~9~~d) Upon receipt of a registration statement, the Chief Clerk will assign a new docket or sub-docket number to the filing.

~~(10)~~ The Chief Clerk will deliver ~~10~~ 16 copies of the registration statement to the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration for distribution by the Coordinator to State agencies having an interest in the filing for information only.

(e) No later than ten (10) business days after the registration statement is filed with the Commission, the Public Staff shall, and any other party in interest may, file with the Commission and serve upon the applicant a notice regarding whether the application is complete and identifying any deficiencies. If the Commission determines that the registration statement is not complete, the owner of the renewable energy facility will be required to file the missing information. Upon receipt of all required information, the Commission will promptly issue an order accepting the registration or setting the matter for hearing.

(~~11~~f) Any of ~~T~~the following actions may result in ~~the ineligibility of renewable energy certificates to be sold to electric power suppliers in North Carolina, forfeiture of payments, fines, or other penalties~~ revocation of registration by the Commission:

(~~i~~1) falsification of or failure to disclose any required information in the registration statement or annual filing;

(~~ii~~2) failure to remain in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources; ~~or~~

(~~iii~~3) remarketing or ~~otherwise~~ reselling any renewable energy certificate (whether or not bundled with ~~the purchase of~~ electric power) after it has been sold to an electric power supplier or any other person to comply ~~for the purpose of compliance~~ with G.S. 62-133.7 or for any other purpose, including another renewable energy portfolio standard or voluntary purchase of renewable energy ~~purchase program~~ certificates in North Carolina or any other state~~.~~ or country, or offering or selling the electric power associated with the certificates with any representation that the power is bundled with renewable energy certificates; or

(4) failure to allow the Commission or the Public Staff access to its books and records necessary to audit REPS compliance.

Rule R8-67 is added as follows:

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

(a) Definitions.

(1) The following terms shall be defined as provided in G.S. 62-133.7: “Combined heat and power system”; “demand-side management”; “electric power supplier”; ~~“energy efficiency measure”;~~ “new renewable energy facility”; “renewable energy certificate”; “renewable energy facility”; “renewable energy resource”; ~~“demand-side management”;~~ and “incremental costs.”~~.~~

(2) “Avoided cost rates” ~~shall be defined as~~ mean an electric power supplier’s most recently approved or established avoided cost rates in North Carolina, as of the date the contract is executed, for purchases of electricity from qualifying facilities pursuant to the provisions of 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 such a 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; provided, however, that development of such estimates of avoided cost by an electric public utility shall include consideration of the avoided cost rates then in effect as established by the Commission. Determinations of avoided costs, including estimates thereof, shall be subject to continuing Commission oversight and, if necessary, modification should circumstances so require.

(3) ~~"REPS Credits" shall be defined as credits claimed by an electric public utility, electric membership corporation, or municipal electric supplier from eligible sources pursuant to G.S. 62-133.7(b)(2) or (c)(2). Eligible sources include electric power or associated renewable energy certificates derived from renewable energy resources on or after January 1, 2008; reduced energy consumption through the implementation of energy efficiency measures on or after August 20, 2007; and, for electric membership corporations and municipal electric suppliers, reduced energy consumption through the implementation of demand-side management on or after August 20, 2007.~~ "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" ~~shall be defined as~~ means the number of accounts within each customer class as of December 31 ~~of~~ for a given calendar year and, unless approved otherwise by the Commission pursuant to subsection (c)(4), determined in the same manner as that information is reported to the Energy Information Administration (EIA), United States Department of Energy, for annual electric sales and revenues reporting.

(b) ~~REPS compliance.~~

~~(1)~~ REPS compliance plan. —

(1) Each year, ~~B~~beginning in 2008~~ and for each year thereafter~~, each electric power supplier shall file with the Commission ~~sufficient information on a calendar year basis regarding~~ the electric power supplier's plan for ~~meeting the requirements of~~ complying with G.S. 62-133.7(b), (c), (d), (e) and (f). The plan shall cover at least ~~during the two-year period including~~ the current and immediately subsequent two calendar years~~, including~~. At a minimum, the plan shall include the following information:

(i) a specific description of the electric power supplier's ~~plan for compliance~~ planned actions to comply with G.S. 62-133.7(b), (c), (d), (e) and (f) for each year;

(ii) a list of executed contracts ~~for the~~ to purchase ~~of electric power or associated~~ renewable energy certificates ~~derived from renewable energy resources~~ (whether or not bundled with electric power), including type of renewable energy resource, expected ~~k~~MWh, and contract duration;

(iii) a list of planned or implemented energy efficiency measures, including a brief description of the measure and projected impacts;

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

(~~i~~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; ~~and~~

(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~~y~~ the projected costs~~.~~; and

(ix) the electric power supplier's registration information and certified statements required by Rule R8-66, to the extent they have not already been filed with the Commission.

(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. 62 133.7(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, ~~B~~beginning in 2009~~ and for each year thereafter~~, each electric power supplier shall file with the Commission ~~sufficient information, including supporting documentation, regarding~~ a report describing the electric power supplier's compliance with the requirements of G.S. 62-133.7(b), (c), (d), (e) and (f) during the previous calendar year~~,~~ ~~including~~. The report shall include all of the following information, including supporting documentation and direct testimony and exhibits of expert witnesses:

(i) ~~a comparison with the previous year's REPS compliance plan;~~

~~(ii)~~ the sources, amounts, and costs of~~ REPS Credits claimed, by type: e.g., self-generation, co-firing, purchased electric power, in-state and out-of-state renewable energy certificates, energy efficiency~~ renewable energy certificates, by source, used to comply with G.S. 62-133.7(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;

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

(~~iv~~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 to comply with ~~the requirements of~~ G.S. 62-133.7(b), (c), (d), (e) and (f);

(v~~i~~) a comparison of actual compliance costs to the annual cost caps;

(vi~~i~~) the status of compliance with the requirements of G.S. 62-133.7(b), (c), (d), (e) and (f);~~ and~~

(vii~~i~~) the identification of any ~~REPS Credits~~ renewable energy certificates to be carried forward pursuant to G.S. 62-133.7(b)(2)f or (c)(2)f;~~.~~

(viii) For each renewable energy facility earning renewable energy certificates used by the electric power supplier to comply with G.S. 62-133.7(b), (c), (d), (e) and (f): the name, address, and owner of the renewable energy facility; and an affidavit from the owner of the renewable energy facility certifying that the energy associated with the renewable energy certificates was derived from a renewable energy resource, identifying the renewable technology used, and listing the dates and amounts of all payments received from the electric power supplier and all meter readings; and

(ix) for electric membership corporations and municipal electric suppliers, reduced energy consumption achieved after January 1, 2008, through the implementation of a demand-side management program.

(32) Each electric public utility shall file its annual ~~REPS compliance plan and~~ REPS compliance report ~~at the same~~ no later than 30 days prior to the time that it files 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. 62-133.7(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 ~~E~~electric membership corporation~~s~~ and municipal electric supplier~~s~~ shall file an ~~REPS compliance plans and~~ REPS compliance report~~s~~ on or before ~~April~~ September 1 of each year. The Commission shall 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 additional direct and rebuttal testimony and exhibits.

(4) ~~The Commission may schedule a public hearing to receive public comments or expert testimony regarding any REPS compliance plan or REPS compliance report.~~

~~(5) Renewable energy certificates (whether or not bundled with the purchase of electric power) claimed by an electric power supplier for compliance with the requirements of G.S. 62-133.7(b), (c), (d), (e) and (f) shall be retired and not used for any other purpose.~~

~~(6)~~ In each electric ~~public utility's~~ power supplier's ~~first-filed~~ initial REPS compliance ~~plan~~ report, the electric ~~public utility~~ power supplier shall propose a methodology for ~~the assessment of the per-account charges to recover the cost of complying~~ determining its cap on incremental costs incurred to comply with ~~the requirements of~~ G.S. 62-133.7(b), (c), (d), (e) and (f) and fund research as provided in G.S. 62-133.7(h)(1), including a determination of year-end number of customer accounts. The proposed methodology may be specific to each electric ~~public utility~~ power supplier, shall be based upon a fair and reasonable allocation of costs, and shall be consistent with G.S. 62-133.7(h)~~(4)~~. The electric ~~public utility~~ power supplier may ~~seek to amend the~~ propose a different methodology ~~approved by the Commission~~ that meets the above requirements in a subsequent REPS compliance

~~plan~~ report filing~~s~~. For electric public utilities, this methodology shall also be used for assessing the per-account charges pursuant to G.S. 62-133.7(h)(5).

(~~7~~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. 62-133.7(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. ~~The~~ 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. 62-133.7(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.

(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. 62-133.7(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. 62-133.7(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. 62-133.7(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. 62-133.7(b), (c), (d), (e) and (f).

(~~c~~e) Cost recovery. ~~[ALTERNATIVE 1, WITH TRUE-UP]~~

(1) For each electric public utility, the Commission shall schedule an annual public hearing pursuant to G.S. 62-133.7(h) to review the costs incurred by the electric public utility to comply with ~~the requirements of~~ G.S. 62-133.7(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 ~~the requirements of~~ G.S. 62-133.7(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~~s~~ 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 ~~through the date that is~~ up to thirty (30) ~~calendar~~ 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 ~~the~~ an electric public utility in any calendar year from its North Carolina retail customers to comply with G.S. 62-133.7(b), (d), (e) and (f) shall not exceed the per-account charges set forth in G.S. 62-133.7(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 may be collected through fixed monthly charges, energy based amounts per

kilowatt-hour, or by a combination of both. Each electric public utility shall ensure that the incremental costs recovered under the REPS rider and REPS EMF rider during the cost recovery period from any given customer account do not exceed the applicable per-account charges set forth in G.S. 62-133.7(h)(4).

(10) ~~The costs associated with the electric power supplied by a new renewable energy facility that are carried over to a future period may be recovered in the year such costs are incurred if~~ Incurred costs may be recovered by an electric public utility in any year after a renewable energy certificate is acquired or obtained until the renewable energy certificate is used to comply with G.S. 62-133.7(b), (d), (e) and (f) as long as the electric public utility's total annual incremental costs incurred in that year do not exceed the per-account annual charges provided in G.S. 62-133.7(h)(4). ~~Such costs not recovered in the year incurred may be recovered in any subsequent year up to the year of retirement of the associated renewable energy certificates as long as total costs charged in such future year are below the annual cap for that year.~~ Incremental costs that exceed the per-account annual charges provided in G.S. 62-133.7(h)(4) in the year in which a renewable energy certificate is used to comply with G.S. 62-133.7(b), (d), (e) and (f) may not be recovered. 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. 62-133.7(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.

~~(c) Cost recovery. [ALTERNATIVE 2, WITHOUT TRUE-UP]~~

~~(1) For each electric public utility, the Commission shall schedule an annual hearing pursuant to G.S. 62-133.7(h) to review the costs incurred by the electric public utility to comply with the requirements of G.S. 62-133.7(b), (d), (e) and (f) during an historical 12-month period and shall establish an annual rider to allow the electric public utility to recover all costs found by the Commission to be recoverable. 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) Unless otherwise ordered by the Commission, the historical 12-month period for each electric public utility shall be the same as its test period for purposes of Rule R8-55.~~

~~(3) 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 costs rider established pursuant to Rule R8-55.~~

~~(4) The incremental costs to be recovered by the electric public utility in any calendar year from its North Carolina retail customers to comply with G.S. 62-133.7(b), (d), (e) and (f) shall not exceed the per-account charges set forth in G.S. 62-133.7(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 may be collected through fixed monthly charges, energy based amounts per kilowatt-hour, or by a combination of both.~~

~~(5) The costs associated with the electric power supplied by a new renewable energy facility that are carried over to a future period may be recovered in the year such costs are incurred if the electric public utility's total annual incremental costs incurred in that year do not exceed the per-account annual charges provided in G.S. 62-133.7(h)(4). Such costs not recovered in the year incurred may be recovered in any subsequent year up to the year of retirement of the associated renewable energy certificates as long as total costs charged in such future year are below the annual cap for that year.~~

~~(6) Each electric public utility may implement deferral accounting for costs considered for recovery through the annual rider. 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. This return is not subject to compounding. However, deferral accounting of costs shall not affect the Commission's authority under this Rule to determine whether the deferred costs may be recovered.~~

~~(7) Each electric public utility shall file the information required under this Rule, 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.~~

~~(8) 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. 62-133.7(h) and setting forth the time and the place of the hearing.~~

~~(9) 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.~~

~~(10) 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.~~

~~(11) The electric public utility may file rebuttal testimony and exhibits of expert witnesses no later than 5 days prior to the hearing date.~~

~~(12) The burden of proof as to whether the costs were reasonable and prudently incurred shall be on the electric public utility.~~

(~~d~~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 ~~the purchase of~~ electric power) prohibiting the seller from remarketing the renewable energy certificates being purchased by the electric power supplier.

(~~e~~g) Metering of renewable energy facilities.

(1) Except as provided below, for the purpose of receiving renewable energy certificates, 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.

(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 with a nameplate capacity of 1 MW or less interconnected behind the utility meter at a customer's location may be measured accurately by an ANSI-certified electric meter not provided by an electric power supplier. The data provided by this meter may be read and self-reported by the owner of the renewable energy facility. The owner of the meter shall comply with the meter testing requirements of Rule R8-13.

(4) Thermal energy produced by a combined heat and power system or solar thermal energy facility ~~that is not used to generate electric power shall be measured accurately with a meter in British thermal units (Btu) and shall earn equivalent renewable energy certificates based on the end-use energy value of electricity of 3,412 Btu per kilowatt-hour~~ 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 megawatt-hour for every 3,412,000 British thermal units of useful thermal energy produced.

(5) Except in those cases where the electric meter is supplied by and read by an electric power supplier, electric generation or thermal energy production data is subject to audit by the Commission, the Public Staff, or an electric power supplier.

Rule R8-68 is added as follows:

Rule 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. 62-133.8 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 ~~s~~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 ~~they are~~ set forth in Rule R8-67(a), or if not defined therein, then as set forth in G.S. 62-3, G.S. 62-133.7(a) and G.S. 62-133.8(a). ~~Otherwise, the following definitions shall apply:~~

(~~1~~2) "Consideration" means anything of economic value paid, given or offered to any person by an electric public utility (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 utility; 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.

(~~2~~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.

(~~3~~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.

~~(4) "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 by 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 for the retail customer's use; and~~

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

(5) "Net lost revenues" means the revenue losses, net of marginal costs avoided ~~costs~~ 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 ~~increases~~ 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. 62-133.8.

(7) "Participation incentive" means any consideration associated with a new demand-side management or energy efficiency measure. ~~"Participation incentive" does not include studies on energy usage.~~

~~(8) "Person" means the same as defined in G.S. 62-3(21).~~

(~~9~~8) "Program" or "measure" means any electric public utility action or planned action that involves the offering of consideration.

(~~10~~9) "Utility incentives" means incentives as described in G.S. 62-133.8(d)(2)a~~.~~-c.

~~(11) "Rate" means the same as defined in G.S. 62-3(24).~~

(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 proposed to be used, (e) the proposed classes of persons to whom it will be offered, and (f) the duration of the proposed measure or program.

(ii) Description. — The electric public utility or electric membership corporation shall describe each measure or program, including its duration, purpose, estimated number of participants, and the impact of 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.

(iii) 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 advertising) and the planned accounting treatment for those costs and benefits~~,~~; (b) the type, amount, and 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.

(iv) 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 ~~t~~Test, the Participant Test, the Utility Cost Test, and the Ratepayer Impact Measure Test.

(v) Communications. — The electric public utility or electric membership corporation shall provide detailed cost information on the amount it anticipates will be spent 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. To the extent available, the electric public utility or electric membership corporation shall include examples of all communication materials to be used in conjunction with the measure or program.

(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. ~~E~~M-100, Sub ~~7~~124,~~ as applicable~~ 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) Description. – The electric public utility shall describe:

a. the measure's objective;

b. total market potential;

c. the proposed marketing plan;

d. the targeted sector;

e. estimated market growth throughout the life of the measure;

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

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

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

i. estimated load shape impacts;~~ and~~

j. a description of market barriers to the proposed measure or program and how the electric public utility intends to address them~~.~~;

k. a description of how the measure's impacts will be evaluated, measured, and verified; and

l. a description of 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.

(ii) 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. 62-133.8;

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

~~b. estimated net lost revenues 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; ~~and~~

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

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. 62-133.8(d)(1).

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 (iii).

(iii) Measurement and Verification Reporting Plan for New Demand-Side Management and Energy Efficiency Measures. — The electric public utility shall describe the industry-accepted methods to be used to measure, verify, and validate the energy and peak demand savings estimated in paragraph (i) above and shall provide a schedule for reporting the savings to the Commission. 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. If the electric public utility plans to utilize an independent third~~-~~ party for purposes of measurement and verification, an identification of the third~~-~~ party and all of the costs of that third~~-~~ party should be included. The costs of implementing the measurement and verification process may be considered as operating costs.

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

(v) 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.

(vi) 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 ~~is encouraged, but not required, to~~ 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.

(d) Procedure.

(1) 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 ~~Commission~~ Rule R1-19 or file a protest pursuant to ~~Commission~~

Rule R1-6. The filing electric public utility or electric membership corporation shall have the opportunity to respond to the petitions or protests 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.

(2) 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. — Except for those costs ~~identified~~ found by the Commission to be unreasonable or imprudently incurred, the costs of new demand-side management or energy efficiency measures approved by application of this rule shall be ~~considered for recovery~~ recovered through the annual rider described in G.S. 62-133.8 and Rule R8-69. The Commission may also consider in the annual rider proceeding whether to approve any utility incentive pursuant to G.S. 62-133.8(d)(2)a~~.~~-c.

Rule R8-69 is added as follows:

Rule 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. 62-133.7(a) and G.S. 62-133.8(a).

(2) “~~Annual~~ DSM/EE ~~R~~rider” means a charge or rate established by the Commission annually pursuant to G.S. 62-133.8(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~~ and electric utility incentives~~.

(3) ~~“Cost recovery period” means the period during which the 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.~~

~~(4)~~ “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) ~~The costs recoverable in e~~Each year~~’s~~ 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 ~~actual~~ expenses expected to be incurred by the electric public utility, during~~ an historical 12-month~~ 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~~, and found by the Commission to be reasonable and prudent~~. 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. 62-133.8(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.

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

(~~3~~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. 62-133.8.

(~~4~~6) Except as provided in (c)(~~2~~3) ~~or (d)(4)~~ 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 ~~begin deferring the~~ 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. However, deferral accounting of costs shall not affect the Commission's authority under this rule to determine whether the deferred costs may be recovered.

(~~5~~7) In approving the first annual rider pursuant to G.S. 62-133.8 for Duke Energy Carolinas, LLC, the Commission shall consider the treatment it approved in Docket No. E-7, Sub 828, of the revenues and costs related to Duke Energy Carolinas' existing demand-side management and energy efficiency measures or programs.

(c) ~~Net Lost Revenues.~~

~~(1) In the annual rider proceeding, an electric public utility may apply for recovery of net lost revenues related to new demand-side management or energy efficiency measures previously approved under Rule R8-68. The burden of proof as to the amount of net lost revenues and the reasonableness and prudence of their inclusion in the rider shall be on the electric public utility.~~

~~(2) An electric public utility shall not be permitted to implement deferral accounting or accrual of a return on net lost revenues unless the Commission approves an annual rider that provides for recovery of an integrated amount of recoverable costs and net lost revenues. In that instance, the Commission shall determine the extent to which deferral accounting and the accrual of a return will be allowed.~~

~~(d)~~ 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) ~~A demand-side management or energy efficiency measure that passes the Ratepayer Impact Measure cost-effectiveness test is presumed not to require the inclusion of incentives associated with that measure in the annual rider.~~

~~(4)~~ 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.

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

(1) Pursuant to G.S. 62-133.8(f), any industrial customer or ~~a~~ large commercial customer may notify its electric power supplier that it has implemented or, in accordance with stated, quantifiable goals, will implement alternative demand-side management or energy efficiency measures. Any such customer may elect not to participate in ~~any~~ new demand-side management and energy efficiency measures under G.S. 62-133.8(f). Any customer that elects this option and notifies its electric public utility will, after the date of notification, be exempt from any annual rider established pursuant to this rule.

(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.

(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 the 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. 62-133.8(d)(1). Within 30 days of the customer's election, the electric public utility shall notify the Commission of an industrial or large commercial customer that elects to participate in a new measure after having initially notified the electric public utility that it declined to participate.

(~~f~~e) Annual Proceeding.

(1) For each electric public utility, the Commission shall schedule an annual rider hearing pursuant to G.S. 62-133.8(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 ~~an historical 12-month~~ 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 ~~an~~ 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 ~~net lost revenues and other electric public~~ utility incentives, including net lost revenues, pursuant to G.S. 62-133.8(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~~, appropriate net~~

~~lost revenues,~~ and appropriate utility incentives at the same time that it files the information required by Rule R8-55.

(3) ~~Unless otherwise ordered by the Commission, the historical 12-month period for each electric public utility shall be the same as its test period for purposes of Rule R8-55.~~

~~(4)~~ The ~~annual~~ 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.

(~~g~~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 ~~cost recovery~~ 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 capacity, energy, and measure unit metric and in the aggregate; and

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

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

a. total expenses for the ~~historical 12-month~~ 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 ~~historical 12-month~~ 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 ~~historical 12-month~~ test period;

d. total summer and winter peak demand reduction per appropriate capacity, energy, and measure unit metric and in the aggregate, as well as any changes in estimated future amounts;~~ and~~

e. total energy reduction in the aggregate and per appropriate capacity, energy and 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.

~~(iii) For each measure for which net lost revenue recovery 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 historical 12-month period, and the proposed jurisdictional allocation factors, as well as any changes in estimated future amounts since last filed with the Commission.~~

(iv) For each measure for which recovery of utility incentives ~~recovery~~ 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~~s~~ established by the Commission during the

~~historical 12-month~~ test period and for all available months immediately preceding the ~~cost recovery~~ rate period.

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

(vii) Projected North Carolina ~~R~~retail monthly kWh sales for the ~~cost recovery~~ rate period for all industrial and large commercial accounts, in 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 utility, by the date specified in subdivision (~~f~~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. 62-133.8(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.

Chapter 8.
Appendix.

REVISED GUIDELINES FOR RESOLUTION OF ISSUES REGARDING INCENTIVE[11] PROGRAMS

1. To obtain Commission approval of a residential or commercial program involving incentives per Rule R1-38 [now Rule R6-95 or R8-68], the sponsoring utility must demonstrate that the program is cost effective for its ratepayers.

(a) Maximum incentive payments to any party must be capable of being determined from an examination of the applicable program.

(b) Existing approved programs are grandfathered. However, utilities shall file a listing of existing approved programs subject to these guidelines, including applicable tariff sheets, and amount and type of incentives involved in each program or procedure for calculating such incentives in each program, all within 60 days after approval of these guidelines.

(c) Utilities shall file a description of any new program or of a change in an existing program, including applicable tariff sheets, and amount and type of incentives involved in each program or procedure for calculating such incentives in each program, all at least 30 days prior to changing or introducing the program.

(d) The matter of the relative efficiency of electricity versus natural gas under various scenarios (space heating alone, space heating plus A/C, etc.) cannot now be resolved. A better approach at this time would be to determine the acceptability of incentive programs herein based on the energy efficiency of electricity alone or of natural gas alone, as applicable.

(e) The criteria for determining whether or not to approve an electric program pursuant to G.S. 62-140(c) should not include consideration of the impact of an electric program on the sales of natural gas, or vice versa.

(f) Approval of a program pursuant to Commission Rule R1-38 [now Rule R6-95 or R8-68] does not constitute approval of rate recovery of the costs of the program. The appropriateness of rate recovery shall be evaluated in general rate cases or similar proceedings.

[11] All incentives referenced in these Revised Guidelines are participation incentives as now defined in Rule R8-68(b)(7).

2. If a program involves an incentive per Rule R1-38 [now Rule R6-95 or R8-68] and the incentive affects the decision to install or adopt natural gas service or electric service in the residential or commercial market, there shall be a rebuttable presumption that the program is promotional in nature.

(a) If the presumption that a program is promotional is not successfully rebutted, the cost of the incentive may not be recoverable from the ratepayers unless the Commission finds good cause to do so.

(b) If the presumption that a program is promotional is successfully rebutted, the cost of the incentive may be recoverable from the ratepayers. The cost shall not be disallowed in a future proceeding on the grounds that the program is primarily designed to compete with other energy suppliers. The amount of any recovery shall not exceed the difference between the cost of installing equipment and/or constructing a dwelling to current state/federal energy efficiency standards and the more stringent energy efficiency requirements of the program, to the extent found just and reasonable by the Commission.

(c) The presumption that a program is promotional may generally be rebutted at the time it is filed for approval by demonstrating that the incentive will encourage construction of dwellings and installation of appliances that are more energy efficient than required by state and/or federal building codes and appliance standards, subject to Commission approval.

3. If a program involves an incentive paid to a third party builder (residential or commercial), the builder shall be advised by the sponsoring utility that the builder may receive the incentive on a per structure basis without having to agree to: (a) a minimum number or percentage of all-gas or all-electric structures to be built in a given subdivision development or in total; or (b) the type of any given structure (gas or electric) to be built in a given subdivision development.

(a) Electric and gas utilities may continue to promote and pay incentives for all-electric and all-gas structures respectively, provided such programs are approved by the Commission.

(b) A builder shall be advised by the sponsoring utility of the availability of natural gas or electric alternatives, as appropriate.

(c) A builder receiving incentives shall not be required to advertise that the builder is exclusively an all-gas or all-electric builder for either a particular subdivision or in general.

4. The promotional literature for any program offering energy-efficiency mortgage discounts shall explain that the structures financed under the program need not be all-electric or all-gas.

5. Duke's proposed Food Service Program shall be modified to include a definition of qualifying equipment and of conventional equipment, and is subject to approval in accordance with guideline number 1 above.

(a) The nature or amount of incentive contained in each program encouraging the installation of commercial appliances (electric or gas) that use the sponsoring utility's energy product, such as Duke's Food Service Program, shall be unaffected by the availability or use of alternate fuels in the applicable customer's facility.

(b) Commercial clients (builders, customers, etc.) who are offered incentives for installation of appliances shall be advised by the sponsoring utility of the availability of natural gas or electric alternatives, as appropriate.

6. Rates, rate design issues, and terms and conditions of service approved by the Commission are not subject to these guidelines.

7. Pending applications involving incentive programs are subject to these guidelines.