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Sep 18 2015

September 18, 2015

Via Electronic Filing

Ms. Gail Mount
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

RE: In the Matter of: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014
Docket No. E-100, Sub 140

Dear Ms. Mount:

Enclosed for filing in the referenced docket is the Proposed Order of Southern Alliance for Clean Energy. A copy of the proposed order in Microsoft Word will be submitted to briefs@ncuc.net. By copy of this letter, I am serving all parties of record on the service list. Please let me know if you have any questions about this filing.

Sincerely,

s/ Gudrun Thompson

GT/rgd
Enclosures
cc: Parties of Record

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

In the Matter of:
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014

PROPOSED ORDER OF SOUTHERN ALLIANCE FOR CLEAN ENERGY[1]

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

Section 210 of PURPA and the regulations promulgated pursuant thereto by the FERC prescribe the responsibilities of the FERC and of state regulatory authorities, such as this Commission, relating to the development of

[1] SACE's proposed order is limited in scope to those issues raised by SACE in its initial comments, and addressed in its reply comments, in Phase Two of this proceeding.

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

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

With respect to electric utilities subject to state jurisdiction, the FERC delegated the implementation of these rules to the State regulatory authorities. State commissions may implement these rules by the issuance of regulations, on

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a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules.

The Commission determined to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by the electric utilities to the QFs with which they interconnect. The Commission also has reviewed and approved other related matters involving the relationship between the electric utilities and such QFs, such as terms and conditions of service, contractual arrangements and interconnection charges.

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

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On February 25, 2014, in the above-captioned docket, the Commission issued its Order Establishing Biennial Proceeding and Scheduling Hearing. For the purpose of considering various issues raised in the 2012 avoided cost proceeding in Docket No. E-100, Sub 136 (the Sub 136 proceeding), the Commission initiated the 2014 avoided cost proceeding in advance of the filing of new proposed rates, stating that such filing would be required by a subsequent Commission order. The Commission scheduled an evidentiary hearing to consider changes to the method used to calculate avoided cost payments. Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, Inc. (DEP), Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), Western Carolina University (WCU), and New River Light and Power Company (New River) were made parties to the proceeding. The Commission established May 30, 2014, as the deadline for interventions by interested persons; set the evidentiary hearing for July 7, 2014, at 1:30 p.m.; and required that direct testimony and exhibits regarding the proper method to determine avoided costs payments, particularly capacity payments, be filed by April 17, 2014, that responsive testimony be filed by May 30, 2014, and rebuttal testimony by June 20, 2014.

Following the evidentiary hearing, the Commission issued an Order Setting Avoided Cost Parameters on December 31, 2014 (Phase One Order). The Phase One Order, among other things, established certain parameters by which avoided cost rates should be calculated and required that DEC, DEP,

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DNCP, WCU, and New River file proposed avoided cost rates 60 days from the issuance of the Order (by March 2, 2015).

On January 8, 2015, the Commission issued an Order Establishing Procedural Schedule and Scheduling Public Hearing, stating that its Phase One Order had resolved several outstanding issues and that it was now appropriate to proceed with the second phase of the E-100, Sub 140 proceedings, focusing on the proposed rates to be filed by the utilities in the usual manner as has been done in these biennial proceedings. The Order required the utilities to file their proposed rates and standard form contracts in accordance with the determinations and guidance set forth in the Commission's Phase One Order; allowed additional parties to petition the Commission for leave to intervene; and provided for the filing of comments and exhibits and proposed orders by all parties.

On March 2, 2015, DEC, DEP, and DNCP (collectively, the Utilities) filed their proposed avoided cost rates, standard power purchase agreements (PPAs), and terms and conditions (the March 2, 2015 Filings). On June 22, 2015, the Public Staff, the North Carolina Sustainable Energy Association (NCSEA) and the Southern Alliance for Clean Energy (SACE) each filed initial comments on the March 2015 Filings. On August 7, 2015, the above parties filed reply comments (with DEC and DEP filing joint reply comments).

Based on the entire record in this proceeding, the Commission makes the following:

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FINDINGS

1. The Utilities have failed to comply with the Commission's requirements that in determining avoided capacity costs under the peaker method, they calculate the installed cost of a combustion turbine (CT) using "data from publicly available industry sources" and tailor those data "only to the extent clearly needed to adapt any such information to the Carolinas and Virginia."

2. In tailoring CT cost data for purposes of its avoided capacity cost determination, it was inappropriate for DNCP to base its installed CT cost estimate on the Siemens CT rather than the GE 7FA CT, which is more representative of the CTs in DNCP's fleet and in the PJM Interconnection. In addition, it was inappropriate for DNCP to make adjustments to the publicly available CT cost estimate without adequate justification.

3. In determining the carrying cost to be used in its avoided capacity cost calculation, it was reasonable for DNCP to assume a CT useful life longer than that assumed in the industry sources on which it relied, because DNCP's useful life assumption was supported by a publicly filed depreciation study. In the absence of publicly filed depreciation studies, it was not appropriate for DEC and DEP to substitute a longer useful CT life in place of the useful CT life used in the industry source on which they relied.

4. The Utilities inappropriately included economies of scope when calculating the installed cost of a CT.

5. When developing fuel forecasts for the purposes of calculating avoided energy costs, it is inappropriate for DEC and DEP to use 10 years of future spot

prices and other forward price data, in direct contrast to several earlier IRP and avoided costs filings.

6. In calculating avoided energy costs, the Utilities have not fully captured the fuel price hedging benefits that result from renewable energy purchases from QFs.

AVOIDED CAPACITY COSTS

DISCUSSION AND CONCLUSIONS FOR FINDING NOS. 1-4

In its Phase One Order, the Commission stated, "because the focus of the peaker method is on a 'hypothetical CT', for the next phase of this proceeding the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data."[2] The Commission further instructed that "Data on the installed cost of [a] CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia."[3]

DEC and DEP's Use of Non-Public Data in Calculating Installed CT Costs

In its initial comments, SACE asserted that DEC and DEP had failed to comply with the Commission's admonition in the Phase One Order to use data from publicly available industry sources in calculating the installed cost of a CT. Instead, DEC and DEP required intervenors to obtain the data through informal discovery under the terms of a confidentiality agreement. NCSEA, similarly, took issue with DEC's and DEP's reliance on Electric Power Research Institute (EPRI)

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[2] *Order Setting Avoided Cost Parameters*, p. 48 (Dec. 31, 2014).
[3] *Order Setting Avoided Cost Parameters*, Ordering Paragraph No. 6 (Dec. 31, 2014).

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data, which is available to the public only for purchase (at a cost of $75,000 for non-EPRI members), as well as data obtained from an engineering firm, all of which was redacted from the public version of DEC's and DEP's March 2, 2015 filings. Public Staff likewise noted in its initial comments that the EPRI data relied on by DEC and DEP is available by paid subscription only, "which limits the public availability of the cost information, as opposed to the reports prepared by the U.S. Department of Energy, Energy Information Administration (EIA) and publications by PJM and other Regional Transmission Organizations (RTOs)." Initial Statement of the Public Staff at 6 n.5. Public Staff further noted that "the projected capital cost for an installed CT is the single most important factor in determining the avoided capacity rate," making the public availability and transparency of this information all the more important. Initial Statement of the Public Staff at 6.

In its reply comments, the Public Staff reiterated that the Utilities should strive to utilize data from publicly available sources and provide clear justifications for any adjustments made to the publicly available data. DEC and DEP replied that the EPRI data they relied upon did meet the "publicly available" standard adopted by the Commission, despite the fact that EPRI's data are available to non-EPRI members only for purchase.

The Commission disagrees with DEC and DEP and concludes that copyrighted, subscription-only data such as those available for purchase from EPRI cannot be considered to be "publicly available." The Commission reiterates the requirement in its Phase One Order and directs DEC and DEP to use data

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from publicly available industry sources, such as the PJM Net Cost of New Entry report (Brattle Report), in calculating installed CT costs.

The Utilities' Tailoring of Publicly Available CT Cost Data

DNCP's Use of the Siemens CT

DNCP based its installed CT cost estimate on a Siemens model CT, rather than the GE 7FA CT that is more representative of the CTs in DNCP's fleet and in the PJM Interconnection. As pointed out by the Public Staff, the Siemens CT is the lowest-cost CT evaluated by DNCP. In their initial comments, the Public Staff and NCSEA both questioned DNCP's choice of a Siemens CT in calculating avoided capacity costs and further critiqued adjustments made to the costs. As the Public Staff noted, "DNCP does not have a Siemens Model CT in its fleet, nor does it have experience with the construction and operation of a Siemens Model CT. As a result, a number of other adjustments such as the applicable contingency factor associated with the facility, capital spare parts, and O&M would need to be adjusted to reflect DNCP's limited experience with the unit." Initial Statement of the Public Staff at 37. The Public Staff again noted this concern in its reply comments: "The Public Staff's concern with such adjustments is illustrated by DNCP's substitution of the lower costs associated with the Siemens SGT6500F CT from Gas Turbine World in place of the GE 7FA turbine prices used in the 2014 Brattle Report, despite the fact that the authors of the 2011 and 2014 Brattle Reports surveyed the CTs built around the country and concluded that the GE 7FA model is the predominant CT model built and best turbine on which to base its cost of new entry." Reply Comments of the Public Staff at 5.

The Commission concludes that DNCP's substitution of the Siemens CT was not clearly needed to adapt the publicly available CT cost data to the Carolinas and Virginia, and accordingly, the Commission directs DNCP to recalculate its avoided capacity cost using the Brattle Report's cost estimate.[4]

<u>DNCP's Tailoring of CT Installation Costs</u>

SACE raised the concern in its initial comments that DNCP made a number of additional downward adjustments to its installation costs beyond its selection of the Siemens CT. The cumulative effect of DNCPs adjustments is to significantly lower the installed CT costs. The downward adjustments related to construction and owner costs such as pollution control costs, construction labor costs, and electric and gas interconnection costs. NCSEA also highlighted the number and significance of these adjustments in its initial comments: "Despite the fact that the Brattle Report provides an installed CT cost estimate that is geographically tailored for Dominion's North Carolina and Virginia service territories, DNCP made more than a dozen different adjustments and modifications, each of which reduced DNCP's cost per kW below the estimate provided in the Brattle Report." As described in NCSEA's initial comments, DNCP's tailoring adjustments ultimately reduced the original Brattle Report's

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[4] NCSEA also critiqued DNCP's use of a 10% contingency factor for engineering, construction and procurement costs ("EPC"), plus a 9% owner's contingency for non-EPC, as assumed in the Brattle Report. SACE concurred that the combination of DNCP's limited experience with the Siemens CT unit and the very rough nature of the cost estimate would require using a higher contingency factor in determining avoided capacity cost. Because the Commission concludes that it was inappropriate for DNCP to rely on the Siemens CT cost, it is appropriate for DNCP to use the contingency factor in the Brattle Report.

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$977 per kW CT installation cost estimate down to $485 per kW. Initial Comments of NCSEA at p. 20. The Public Staff agreed in reply comments with SACE and NCSEA that the Utilities should "provide clear justifications for any adjustments made to the publicly available data." Reply Comments of the Public Staff at 5. DNCP disagreed with NCSEA and SACE in its reply comments, asserting that its numerous tailoring adjustments were warranted.

The Commission concludes that DNCP's tailoring adjustments have not been fully justified and exceed those clearly needed to adapt any such information to the Carolinas and Virginia. The Commission directs DNCP to remove all adjustments that are not clearly needed and have not been justified from its avoided capacity cost calculations.

<u>The Utilities' Assumptions Regarding Useful Life of a CT</u>

Although the installed cost of a CT is the major component of a utility's calculation of avoided capacity costs, the utility's financial carrying cost for the CT is the second-largest component in the calculation. One of the various factors that determine the carrying cost of a CT is its useful life. In its December 31, 2014 *Order Setting Avoided Cost Parameters*, the Commission specified that "a reasonable estimate of useful life of a CT" should be used in the calculation of the installed cost of a CT to be included in the calculation of avoided capacity costs.[5]

In its initial comments, NCSEA noted that all three Utilities assumed a useful life for a CT that is longer than both the publicly available Brattle Group/Sargent & Lundy estimate of 20 years and the confidential EPRI TAG

[5] *Order Setting Avoided Cost Parameters*, Ordering Paragraph No. 7 (Dec. 31, 2014).

assumption. Initial Comments by NCSEA at page 35. In its reply comments, SACE concurred with NCSEA, noting that the Brattle Group and Sargent & Lundy have determined that the appropriate useful life to assume in calculating the cost of new entry in ISO-New England is 20 years for all technologies, and that a useful life assumption of 15 to 20 years is more reasonable for use in economic modeling than the much longer useful life assumed by the Utilities.

In their respective reply comments, DEC and DEP, as well as DNCP, replied that their assumptions regarding the useful life of a CT were supported by asset depreciation studies and operational experience. Only DNCP has filed its depreciation study publicly with the Commission, however. DNCP's study supports the use of a 36-year useful life assumption for a "hypothetical CT" based on the GE CT which makes up most of DNCP's CT fleet. In the absence of publicly available depreciation studies conducted by DEC and DEP, it was inappropriate for DEC and DEP to employ CT useful life assumptions longer than those in the publicly available data.

<u>DEC and DEP's Inclusion of Economies of Scope in Calculating CT Costs</u>

In the first phase of this proceeding, the Commission determined that it is appropriate for the Utilities to use the peaker methodology to calculate avoided costs. Under the peaker method, the calculation of avoided capacity cost is based primarily on the installed cost of a hypothetical natural gas CT. The Commission's Phase One Order details the costs associated with construction of a CT that are to be included in capacity cost calculations, and states that although they may include economies of *scale* for up to four CTs constructed at

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the same site, "DEC, DEP, and DNCP shall not include any economies of *scope* associated with the construction of more than one CT at the same time." (Emphasis added.)

In its initial comments, SACE commented that DEC and DEP included both economies of scale and scope when calculating the installed cost of a CT for purposes of the avoided capacity costs used in their March 2, 2015 Filings, despite the statement in the Phase One Order that the Utilities should not include any economies of scope associated with the construction of more than one CT at the same time. NCSEA similarly commented that DEC and DEP erroneously included economies of scope in calculating the installed costs of a CT.

DEC and DEP replied that they had excluded economies of scope to the greatest extent possible, and noted that the Public Staff had not objected to their treatment of economies of scale and scope. The Public Staff did not take issue with these adjustments in its initial comments, but agreed with SACE and NCSEA in its reply comments that economies of scope were not properly excluded by the Utilities from the installed cost of a CT, and recommended that the Commission direct the Utilities to recalculate their avoided capacity costs to ensure that all economies of scope are excluded.

The Commission finds that DEC and DEP inappropriately included cost savings associated with construction of a hypothetical CT due to economies of scope, and directs DEC and DEP to recalculate their avoided capacity costs to ensure that all economies of scope are excluded.

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AVOIDED ENERGY COSTS

DISCUSSION AND CONCLUSIONS FOR FINDING NO. 6

DEC's and DEP's Use of Natural Gas Price Forecasts

Fuel prices represent the major component in the calculation of avoided energy costs. For their March 2 filings, DEC and DEP each incorporated 10 years of future spot prices and other forward price data in their avoided energy cost, in direct contrast to several earlier IRP and avoided cost filings. In the 2014 IRPs, DEC and DEP relied on 5 years of forward price data rather than 10 years. In both its 2012 IRP and 2012 avoided cost calculations, DEC used a shorter term (two years) for forward price data, combined with 24 months of transitional data and a long-term natural gas price forecast.

In their initial comments, both the Public Staff and NCSEA critiqued DEC's and DEP's use of forward price data in developing their avoided energy costs. According to the Public Staff, an over-reliance on forward price data can call into question the reliability of the long-term forecasts. As pointed out by the Public Staff, using futures prices for 10 years before switching to gas forecast price is inappropriate because the market for 10-year futures is relatively illiquid. Accordingly, the Public Staff recommended using no more than five years of future markets data in their fuel price forecasts, consistent with DEC/DEP's approach in their 2014 IRPs. NCSEA contended that by emphasizing unusually low futures market prices and ignoring the likelihood of an upswing in gas prices, DEC and DEP (as well as DNCP) have reduced their avoided energy costs to an unreasonably low level. NCSEA recommended that that DEC's and DEP's actual 2014 IRP fuel forecasts be used to recalculate their avoided energy costs, pointing out that DEC and DEP had relied on their 2014 IRP fuel forecasts in three separate recent filings with the Commission.

In its reply comments, SACE agreed with the Public Staff and NCSEA's criticisms of the DEC and DEP fuel price forecasts as proposed and recommended that DEC and DEP use only three years of NYMEX Henry Hub natural gas futures prices and then transition to long-term forecasts when calculating their avoided energy costs. While the Public Staff recommended that DEC and DEP use futures for five years, SACE recommended using futures for only two to three years. In making this recommendation, SACE reasoned that the number of contracts in excess of the two-to-three year window is extremely small (be it for 4-year or 5-year or 10-year futures), so using futures prices for a two-to-three year window effectively reduces reliance on positions with low trade volumes.

Based on the foregoing, the Commission concludes that DEP and DEC should use only the next three years of NYMEX Henry Hub natural gas futures prices before transitioning to long-term forecasts when calculating their avoided energy costs.

DISCUSSION AND CONCLUSION FOR FINDING NO. 7

The Utilities' Calculation of the Fuel Hedging Value of Renewables

The Commission recognized in its Phase One Order that "renewable generation provides fuel price hedging benefits because a utility's purchase of energy from a QF reduces the amount of fuel the utility otherwise would need to

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purchase" and accordingly, ordered that each of the Utilities "shall calculate and include the fuel hedging benefits associated with purchases of renewable energy . . . in the avoided energy component of its avoided cost rates to be filed in phase two of this proceeding."[6]

In their initial comments, NCSEA, the Public Staff and SACE each took the position that the Utilities had failed to reflect the full fuel-hedging value of renewable energy purchases in their avoided energy costs. SACE's initial comments critiqued DEC's and DEP's use of the "ask" gas price forecast in calculating the fuel hedging benefits associated with purchases of renewable energy. In addition, SACE took issue with DNCP's assumption of only one year of hedge value, contending that the fuel price hedge value should be accounted for in each year of a QF contract, regardless of the hedge horizon, as it is unreasonable to assume that the utility will not hedge beyond the first year of the QF contract. SACE also took issue with DNCP's assumption that renewable generation could displace any non-nuclear generation with equal likelihood (rather than first displacing natural gas-fired generation). The Public Staff and NCSEA also critiqued DEP's and DEC's bid/ask method of calculating fuel hedging value, as well as certain aspects of DNCP's approach.

The Public Staff recommended that the Utilities use the Black-Scholes Option Pricing Model or a similar method to calculate the hedge value of renewable energy purchases. NCSEA and SACE also supported the use of the Black-Sholes model, while stressing the importance of using the correct inputs and assumptions. The Commission concludes that the Black-Scholes Option

[6] *Order Setting Avoided Cost Parameters*, Ordering Paragraph No. 9 (Dec. 31, 2014).

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Pricing Model endorsed by the Public Staff is a reasonable method for calculating hedge value, and directs the Utilities to recalculate the fuel price hedging value of renewable energy purchases using the Black-Scholes model. The Commission will carefully scrutinize the inputs and assumptions used by the Utilities in their calculations.

IT IS, THEREFORE, ORDERED as follows:

1. Within 60 days of this order, DEC, DEP and DNCP shall file revised avoided cost rates and standard contracts consistent with the following ordering paragraphs.

2. DEC and DEP shall either a) file for public inspection, no later than five days from the date of this Order, the capacity ($/kW) and energy (cents/kWh) cost data associated with the installed CT cost estimate underlying the capacity cost calculation, or b) recalculate their avoided capacity costs using publicly available data for the installed CT cost estimate.

3. The utilities shall recalculate their avoided capacity costs consistent with the following:

    a. DNCP shall use the GE 7FA CT included in the Brattle Report to develop its installed CT cost estimate;

    b. DNCP shall remove all tailoring adjustments to the CT installation costs that are not clearly needed to adapt any such information to the Carolinas and Virginia;

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c. DEC and DEP shall use an assumption regarding useful CT life that is derived from publicly available industry data; and

d. DEC, DEP and DNCP shall remove adjustments for economies of scope.

4. DEC, DEP and DNCP shall recalculate their avoided energy costs as follows:

a. DEC, DEP and DNCP shall recalculate the fuel price forecasts using only the next three years of NYMEX Henry Hub natural gas futures prices before transitioning to long-term forecasts.

b. DEC, DEP and DNCP shall recalculate the fuel price hedging benefits associated with purchases of renewable energy from QFs using the Black-Scholes Option Pricing Model or a similar method.

ISSUED BY ORDER OF THE COMMISSION.

This the __ day of ______________, 2015.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount, Chief Clerk

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CERTIFICATE OF SERVICE

I certify that the foregoing Proposed Order of Southern Alliance for Clean Energy as filed today in Docket No. E-100, Sub 140 has been served on all parties of record either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 18th day of September, 2015.

_s/ Robin G. Dunn_______

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