LAW OFFICE OF CHARLOTTE MITCHELL

PO BOX 26212
RALEIGH, NORTH CAROLINA 27611
919-260-9901
www.lawofficecm.com

August 7, 2015

Gail Mount
Chief Clerk
North Carolina Utilities Commission
430 N. Salisbury Street
Raleigh, NC 27603 – 5918

Re: Reply Comments by NCSEA – Public
NCUC Docket No. E-100, Sub 140

Dear Ms. Mount:

Enclosed for filing in the above-referenced docket are the Reply Comments by NCSEA – Public.

Should you have any questions or comments, please do not hesitate to call me. Thank you in advance for your assistance and cooperation.

Regards,

/s Charlotte Mitchell

4847-9065-5268, v. 1

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Biennial Determination of Avoided Cost	)	**REPLY COMMENTS**
Rates for Electric Utility Purchases from	)	**BY NCSEA**
Qualifying Facilities - 2014	)	

On January 8, 2015, the North Carolina Utilities Commission (the "Commission") entered its Order Establishing Procedural Schedule and Scheduling Public Hearing, as subsequently amended by orders dated April 15, 2015 and May 29, 2015, directing the electric utilities and intervenors to file reply comments on or before Monday, July 27, 2015. In light of the foregoing, the North Carolina Sustainable Energy Association ("NCSEA"), having become a party to this proceeding pursuant to that Order Granting Petition to Intervene entered by the Commission on February 27, 2014, by and through undersigned counsel, respectfully submits these reply comments for consideration by the Commission.[1]

REPLY COMMENTS

I. Understatement of Avoided Energy Costs

[1] In its initial comments filed in this docket on June 22, 2015, NCSEA focused on the proposed rates, power purchase agreements and terms and conditions of Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, Inc. ("DEP") and Virginia Electric and Power Company d/b/a Dominion North Carolina Power ("DNCP") (collectively, the "Utilities") filed in this docket on March 2, 2015 (the "March 2015 Filings"). In these reply comments, NCSEA replies to the initial comments of the Public Staff and of the Southern Alliance for Clean Energy ("SACE") on the Utilities' March 2015 Filings.

As explained in its initial comments, NCSEA's review of the March 2015 Filings revealed that the Utilities' methods of calculating future fuel prices overemphasize futures market data and underestimate long term prices, thereby understating the Utilities' avoided energy costs.[2] To a large extent, the Public Staff echoes NCSEA's concerns, noting the Utilities changed methodologies from those used in their respective 2014 IRPs and, in doing so, placing much greater emphasis on futures market data, allowing the Utilities to develop substantially lower avoided energy cost estimates than if they had continued to use the same assumptions and methodology used in the 2014 IRPs.

A. DEC and DEP

In its Initial Statement, the Public Staff expresses concern with the price forecasts used by DEC and DEP in calculating their avoided energy costs.[3] Noting DEC's and DEP's use of 10 years of "forward price data"[4] in this proceeding as compared to DEC's and DEP's use of only five (5) years of "forward price data" in their 2014 IRPs and noting that an "over-reliance on forward price data can call into question the reliability of the long-term forecasts," the Public Staff recommends that the Commission require DEC and DEP: i) to reconstruct their natural gas and coal forecasts using the same approach utilized in their 2014 IRP – i.e., to use only five (5) years of forward price data; and ii) to re-calculate their avoided energy costs using the reconstructed forecasts.[5]

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[2] See Initial Comments by NCSEA, N.C.U.C. Docket No. E-100, Sub 140, June 22, 2015 ("NCSEA's Initial Comments"), Section I.

[3] See Initial Statement of the Public Staff, N.C.U.C. Docket No. E-100, Sub 140, June 22, 2015 ("Public Staff's Initial Statement"), p. 11, 17.

[4] In the interest of clarification, with respect to terminology, the Public Staff uses "forward price data" and NCSEA uses "futures market data" when referring to the same data.

[5] Id. pp 33-34.

For the reasons set forth in NCSEA's Initial Comments, NCSEA shares the Public Staff's concerns regarding an overreliance on futures market data.[6] NCSEA also notes that this methodological change was not proposed by the Utilities during the first phase of the proceeding. DEC's and DEP's use of ten (10) years of futures market data, instead of only five (5) years, results in an understatement of long-term fuel prices and, by extension, avoided energy costs. Approval of understated avoided energy costs will discourage QF development, and ratepayers will bear the risk and burden of paying for electricity generated by the Utilities at a cost far in excess of the avoided costs estimated by the Utilities in this proceeding

NCSEA supports the Public Staff's position that DEC and DEP should use no more than five (5) years of futures market data when constructing their fuel price forecasts.[7] NCSEA notes that use of five (5) years of future market data is not only consistent with DEC and DEP's IRP forecasts but is also more consistent with DEC's and DEP's fuel procurement practices. In December 2014, just three (3) months prior to the March 2015 Filings, the Duke Energy Carolinas, LLC Fuel Procurement Practices Report was filed with the Commission.[8] The Fuel Report provides as follows:

Determining Natural Gas Requirements:

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[6] See also Affidavit of Ben Johnson, Ph.D., N.C.U.C. Docket No. E-100, Sub 140, August 7, 2015 (the "Johnson Affidavit"), ¶¶ 21-28.

[7] Use of a five (5) year forecast appears to be consistent with the Public Staff's position that "the use of five years is appropriate because the market for ten year futures is relatively illiquid. . . ." Public Staff's Initial Statement, p. 29.

[8] See Duke Energy Carolinas, LLC Fuel Procurement Practices Report, N.C.U.C. Docket No. E-100, Sub 47A, December 22, 2014 ("Fuel Report"). The Fuel Report explains that "DEC is the Asset Manager for Duke Energy Progress (DEP) under an approved affiliated Asset Management Agreement (AMA), and procures all the natural gas supply for the Carolinas regulated gas generation fleet needs." Therefore, it appears that the usage forecasts and procurement activities provided in the Fuel Report apply to DEC and DEP.

> Natural gas usage forecasts for the Carolinas regulated gas generation fleet are produced on a periodic basis. The forecast are generated for five and twenty year time frames. The five year forecast is referred to as the mid - term forecast and is typically produced monthly. Beyond the five year forecast period, a fifteen year usage forecast is produced typically at least twice a year. The mid-term five year forecast produces monthly natural gas usage for all generation facilities and in total. This forecast incorporates various inputs that includes but is not limited to, system load forecasts, market fuel and emission prices, unit capacity ratings and heat rates, and maintenance schedules.[9]

The fact that DEC and DEP are actually procuring natural gas based on a five year usage forecast, which forecasts fuel prices five (5) years out, further calls into question whether DEC's and DEP's use of ten (10) years of futures market data in the instant proceeding was purposefully chosen to drive down the avoided energy cost calculation.

While NCSEA generally supports the Public Staff's recommendation of using no more than five (5) years of future markets data in the fuel price forecasts, NCSEA does not support the Public Staff's recommendation that DEC and DEP update their 2014 IRP forecasts; instead, NCSEA recommends that DEC's and DEP's actual 2014 IRP fuel forecasts be used to recalculate their avoided energy costs in order to achieve PURPA's objective of ratepayer indifference.[10]

The Commission unquestionably emphasized, in its Order of Clarification, that the Utilities should use "up-to-date data in determining the inputs" for avoided cost rates, and NCSEA recognizes that the 2014 IRP fuel price forecasts were developed in conjunction with the September 2014 filing deadline for the IRPs.[11] However, there are at least two, and likely three, reasons why the Commission should direct DEC/DEP to use

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[9] Fuel Report, "Duke Energy Carolinas ("DEC") Natural Gas Procurement Procedures March 2014."

[10] See also Johnson Affidavit, ¶ 27.

[11] Order of Clarification, N.C.U.C. Docket No. E-100, Sub 140, March 6, 2015, p. 3.

their 2014 IRP fuel forecasts in the recalculation of avoided energy costs. First, as pointed out in NCSEA's Initial Comments, though overlooked by the Public Staff, DEP relied on its 2014 IRP fuel price forecasts on April 25, 2015 to support its application for a certificate of public convenience and necessity ("CPCN") to construct the 84 MW Sutton blackstart CT ("Sutton Blackstart CT Project"), an application that was made subsequent to DEC's and DEP's March 2015 Filings. Second, also pointed out in NCSEA's Initial Comments, though also overlooked by the Public Staff, is the fact that DEC's and DEP's Avoided Cost Informational Filing, filed in this docket on December 23, 2014 ("DEC/DEP Informational Filing") pursuant to their obligations under PURPA, used the same simulation run and input assumptions to calculate avoided energy costs as had been used in their 2014 IRPs. Third and finally, in the context of DEP's recent request for permission to acquire the ownership interests of the North Carolina Eastern Municipal Power Agency in certain generating facilities, the 2014 IRP data were used to calculate the future fuel savings to DEP customers, which DEP relied on to justify its request.[12]

DEC's and DEP's consistent use of the 2014 IRP fuel price forecasts both prior to and subsequent to their March 2015 Filings supports NCSEA's request that the Commission direct DEC and DEP to use the same fuel prices in this proceeding as they used in their 2014 IRP filings.

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[12] See page seven of the cover letter to the full requirements power purchase agreement between DEP and NCEMPA filed with the FERC in F.E.R.C. Docket No. ER15-74-000 on October 14, 2014, noting that to perform a benefits analysis of the transaction, "DEP evaluated its system revenue requirements over a twenty-year period with and without the Transaction using data from DEP's most current integrated resource plans ('IRPs') that DEP filed with the North Carolina Utilities Commission ('NCUC') and the South Carolina Public Service Commission ('SCPSC') in September 2014." See also Joint Notice of Transfer and Request for Approval of Certificate of Public Convenience and Necessity – NCEMPA Ownership Interests in Generating Facilities of Duke Energy Progress, Inc., N.C.U.C. Docket No. E-2, Sub 1067, April 13, 2015.

The Commission must not allow DEC and DEP to pick and choose different fuel price forecasts depending on the context in which the forecast is being used. DEC's and DEP's avoided energy costs are calculated using the future resource expansion plan set forth in their respective IRPs, in order to most accurately approximate generation that will be avoided by the utility. As such, the fuel price forecasts used in this proceeding should not differ from those used in the IRP. Moreover, if DEC and DEP use the IRP fuel price forecasts to justify requests for the addition of generating facilities close in time to the setting of avoided costs, then the utilities should be required to use the same fuel price forecasts to calculate avoided costs, in order to achieve PURPA's objective of ratepayer indifference.

B. DNCP

As pointed out in NCSEA's Initial Comments, for its March 2015 Filing, DNCP's method of forecasting natural gas prices was based on: 1) futures market data for the first four (4) years; 2) a blend of these data and the fundamental commodity price forecast developed by ICF during the next three (3) years; and 3) the ICF forecast for the remaining years. The overall effect of DNCP's method is that the natural gas price inputs remain at very low levels during the first seven (7) years of the 15-year horizon and never approach, much less reach, the long term historical trend line. DNCP employed a different method in the 2014 IRP proceeding when estimating future natural gas prices. In the IRP proceeding, DNCP gave relatively little weight to futures market data, blending the futures market data with the ICF forecast during just three (3) years (2015 – 2017) and relying entirely on the ICF forecast during all remaining years.

NCSEA does not support the Public Staff's position that the inputs to DNCP's model for calculating its avoided energy costs and the output data from the model are reasonable. Despite emphasizing, in its comments that "one of the most important issues in these biennial proceedings continues to be the need for consistency with the utilities' IRPs," the Public Staff fails request that the Commission direct DNCP to recalculate its avoided energy costs using its 2014 IRP fuel price forecast. The Commission must reject DNCP's use of different fuel price forecasts in the IRP proceeding and the avoided cost proceeding, for the same reasons NCSEA has given in the context of DEC and DEP. In this proceeding, avoided energy costs are calculated using the Utilities' future resource expansion plans set forth in the IRP, in order to most accurately approximate generation that will be avoided by the utility. As such, the fuel price forecasts should not differ from those used in the IRP, thereby maintaining consistency.

II. Non-Compliance with the Order Setting Parameters

A. Calculating Avoided Energy Costs

a. DEC and DEP use generation expansion plans that include carbon emissions control cost

As explained in NCSEA's Initial Comments, in spite of clear direction from the Commission in its Order Setting Parameters[13] to use generation expansion plans that take

[13] Order Setting Avoided Cost Input Parameters, N.C.U.C. Docket No. E-100, Sub 140, December 31, 2014 ("Order Setting Parameters").

into account only known and quantifiable costs, DEC and DEP used IRP expansion plans that take into account costs of carbon emissions control.[14]

The Public Staff expressed concern regarding DEC's and DEP's use of generation expansion plans based on assumptions that include carbon dioxide emissions reduction costs. The Public Staff noted that using a "generation plan that included carbon prices, while at the same time excluding avoided carbon prices as an input into avoided energy rates, can distort the avoided energy calculations and may result in an underestimation of avoided energy costs."[15] The Public Staff recommended that the Commission direct DEC and DEP to recalculate avoided energy costs using generation plans that do not include the cost of carbon dioxide emissions reduction.[16]

NCSEA agrees with the Public Staff and supports its recommendation in this regard. As NCSEA has previously stated, during the evidentiary portion of this proceeding much effort and analysis was devoted to the issue of whether the Utilities' avoided cost calculations should reflect costs associated with the control of carbon emissions, given that their IRPs actually do reflect such costs. Ultimately, until such time as the costs do become known and quantifiable, the Commission determined to address the inconsistency by disallowing the use of expansion plans that reflect speculative assumptions concerning future carbon costs when calculating avoided costs. DEC and DEP have not complied, and the inconsistency remains. The Commission must direct DEC and DEP to recalculate their avoided energy costs using the correct expansion plan.

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[14] DEP/DEC response to NCSEADR2-6, Exhibit 1, 005; DEC Response to PSDR6-3, Exhibit 1, 006-007; DEP Response to PSDR6-4, Exhibit 1, 008 (noting that "the expansion plan utilized for the [March 2015 Filing] is the same as the expansion plan developed in the base case of the 2014 IRP.").

[15] Public Staff's Initial Statement, pp 27-28.

[16] Id., p. 28.

b. The Utilities have not adequately allowed for fuel hedging benefits

As the Commission found in its Order Setting Parameters, "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 purchase."[17] Noting that DEC and DEP have posited in separate proceedings that "a utility's fuel hedging programs to mitigate fuel price volatility can result in significant costs that are borne by ratepayers[,]"[18] the Commission concluded:

> [T]hat there are fuel price hedging benefits associated with solar generation, as well as hydroelectric, landfill gas, and other renewable generation because purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that needs to be purchased. It is appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation.[19]

In light of the foregoing, the Commission directed the Utilities "to calculate and include the fuel hedging benefits associated with purchases of renewable energy in the avoided energy component of its avoided cost rates."[20] In its Initial Statement, the Public Staff took the position that the Utilities have not properly reflected the hedging value of renewables in developing their respective avoided energy costs, taking issue with the method used by each of the Utilities to account for hedging value.[21] Additionally, the Public Staff explained that avoided energy costs should reflect both projected fuel costs and the fuel price hedging benefits provided by QF generation in each year of the

[17] Order Setting Parameters, FOF 12.

[18] Order Setting Parameters, p. 42, fn 2.

[19] Order Setting Parameters, p. 42.

[20] Order Setting Parameters, OP 9.

[21] Public Staff's Initial Statement, p. 35.

contract with the QF.[22] As pointed out in its initial comments, the Southern Alliance for Clean Energy ("SACE"), like the Public Staff, takes the position that hedge value should be accounted for in each year of the 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.[23] NCSEA agrees with the Public Staff and SACE that hedge value must be included in each year of the entire term of the QF power purchase agreement.

Taking issue with the methods utilized by the Utilities, the Public Staff proposed an alternative method, and actually calculated a hedge value, as follows:

> The Public Staff evaluated the prices of at-the-money Henry Hub natural gas options using the Black-Scholes Option Pricing Model. Henry Hub natural gas options were used in the evaluation because, unlike coal, these financial instruments over terms of less than three years are publicly traded in a robust marketplace with transparent prices. Based on this evaluation, the Public Staff determined that a net option price, the price of a call option minus the price of a put option, for "at-the-money" Henry Hub natural gas options is approximately $.04 per dekatherm for the 12- and 24-month hedge terms used by the utilities. The Public Staff then converted the $.04 per dekatherm net option price to a hedge value of 0.028 cents per kWh.[24]

NCSEA shares the concern of the Public Staff that the Utilities have not properly reflected the hedging value of QF generation in their avoided energy cost calculations. NCSEA has reviewed the alternative method proposed by the Public Staff, as well as the calculation of the hedge value, and does not take issue with either in principle. However, NCSEA does take issue with the "risk free interest rate" used by the Public Staff in calculating the hedge value. The Public Staff utilized the Black-Scholes options

[22] Public Staff's Initial Statement, pp 35 - 36.

[23] Initial Comments of Southern Alliance for Clean Energy, p. 6.

[24] Public Staff's Initial Statement, p. 36.

calculator to calculate the hedge value, which is available on-line. The calculator requires the input of an interest rate and instructs that an appropriate rate is a "risk free interest rate."[25] The Public Staff used 1% as the rate; NCSEA proposes that a rate of at least 3.10% be used in the calculation, which is consistent with the range of risk free interest rates used by the Utilities in developing cost of equity estimates in their respective most recent rate case proceedings.[26] Using an interest rate of 3.10%, using all other assumptions and inputs used by the Public Staff, results in a hedge value of 0.9 cents per kWh.[27] Therefore, NCSEA recommends that the Commission direct the Utilities to recalculate the avoided energy component of avoided cost rates, using a hedge value of at least 0.09 cents per kWh in each year of the term of the QF power purchase agreement.

While NCSEA generally supports the Public Staff's proposal in this proceeding, NCSEA notes that the calculation of the fuel price hedging benefit provided by QF generation is a topic being discussed across the country. For example, Austin Energy has recently worked with Clean Power Research, a consulting firm that was retained by Duke Energy to collaborate on the Duke Energy Photovoltaic Integration Study: Carolinas Service Areas (commonly referred to in phase one of this proceeding as the "PNNL Study"), to develop a web-based tool that calculates fuel price hedge value of solar generation.[28] Additionally, in a presentation at a 2014 NARUC staff meeting, efforts to

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[25] Johnson Affidavit, ¶ 41.

[26] Johnson Affidavit, ¶¶ 42-45.

[27] Johnson Affidavit, ¶¶ 46-50.

[28] See Designing Austin Energy's Solar Tariff Using a Distributed PV Calculator, available at: http://www.cleanpower.com/resources/designing-austin-energys-solar-tariff/.

account for the hedging value of QFs was noted as an "upcoming issue" in the context of methodologies for calculating avoided costs.[29] In light of the fact that methodologies related to fuel price hedge value provided by QF generation are likely to be increasingly discussed and analyzed across the country, NCSEA respectfully requests that, in addition to approving the Public Staff's proposed methodology (corrected to incorporate NCSEA's recommendation regarding interest rate and hedge value), the Commission indicate a willingness to revisit this issue in a future proceeding, particularly if a national consensus on methodology emerges.

B. Calculating Avoided Capacity Costs

a. With limited exception, the Commission must reject the adjustments made by the Utilities to the capacity cost data provided in publicly available industry sources

As noted in NCSEA's Initial Comments, when utilizing the peaker methodology, the calculation of avoided capacity cost relates primarily to the installed cost of a natural gas-fired combustion turbine ("CT"). In its Order Setting Parameters, the Commission generally directed the Utilities as follows:

> 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.[30]

Importantly, the Commission specified that the Utilities may adjust such data "only to the extent clearly needed to adapt any such information to the Carolinas and Virginia."

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[29] See A Survey of Avoided Cost Ratemaking Methodologies under the Public Utility Regulatory Policies Act, NARUC Staff Subcommittee on Accounting & Finance Spring 2014 Conference, available at: http://www.narucmeetings.org/Presentations/25%20PURPA%20Avoided%20Cost%20Calculation%20Differences%20Across%20States-Carolyn%20Elefant.pdf.

[30] Order Setting Parameters, p. 48

Additionally, after considering and weighing the voluminous evidence received during the first phase of this proceeding, the Commission established a number of parameters with which the Utilities must comply when calculating—specifically—the installed cost of a CT,[31] and the Commission ordered as follows:

> That, in the calculation of the installed cost a CT, DEC, DEP and DNCP shall include transmission interconnection costs (but not network upgrade costs), equipment and construction costs with a reasonable contingency adder for a hypothetical plant in relatively early stages of planning, a reasonable estimate of useful life of a CT, the cost of land for a greenfield site, and economies of scale for up to four CTs constructed on 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.[32]

Without there being a clear need, DNCP, DEC and DEP have proposed a series of adjustments to cost estimates taken from industry sources. In its initial comments, the Public Staff leaves unchallenged many of these adjustments, even when the adjustments appear to violate the Commission's directive that any adjustments must be "clearly needed to adapt any such information to the Carolinas and Virginia." However, given the attention paid by the Commission to the calculation of the avoided capacity cost estimate during the first phase of this proceeding and in spite of the Public Staff's failure to challenge many of these adjustments, NCSEA urges the Commission to review carefully the Utilities' compliance with: 1) the general requirement that any adjustment to data provided in the publicly available industry source on which the utility relied be "clearly needed" to adapt such information to the Carolinas and Virginia; and 2) the specific parameters established by the Commission for the calculation of the installed cost of a CT.

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[31] See Order Setting Parameters, FOF 16-19.

[32] Order Setting Parameters, OP 7.

1. DEC and DEP

The Public Staff does not take issue with DEC's and DEP's calculation of their respective avoided capacity costs.[33] However, the Public Staff's position appears to be based on its assessment that the installed cost of a CT of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** projected by DEC and of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** projected by DEP falls within the range of installed cost estimates for a CT in North Carolina provided in publicly available industry sources.[34] The Public Staff does take issue with DEC's and DEP's compliance with the specific requirements for calculating the installed cost of a CT set forth in the <u>Order Setting Parameters</u>. However, NCSEA takes the position that DEC and DEP have failed to comply with the general directive that adjustments to estimates provided in publicly available industry sources be "clearly needed" as well as with several of the specific requirements for calculating the installed cost of a CT set forth in the <u>Order Setting Parameters</u>.

As indicated in NCSEA's Initial Comments, DEP and DEC relied primarily on the Electric Power Research Institute ("EPRI") Technical Assistance Guide ("TAG") Version 3.1 Database – 2014 to calculate their respective avoided capacity costs. With respect to contingency factor, DEC and DEP took the **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** contingency factor provided in the EPRI TAG and slashed it **BEGIN CONFIDENTIAL** [redacted]. **END CONFIDENTIAL** Even though the Public Staff has not challenged this adjustment, the Commission should reject the

[33] Public Staff's Initial Statement, p. 10, 16.

[34] Public Staff's Initial Statement, p. 42.

DEP/DEC adjustment as it is not consistent with a "hypothetical plant in relatively early stages of planning." For the reasons discussed in NCSEA's Initial Comments, a contingency factor of 15% to 20% would be appropriate for a plant in relatively early stages of planning.[35] Thus, the Commission should reject the DEC/DEP adjustment, and it should direct DEC/DEP to adjust the contingency factor upward to 15-20%, consistent with publicly available industry sources for a plant in relatively early stages of planning.

As indicated in NCSEA's Initial Comments, with respect to estimate for useful life of the CT, DEC and DEP assumed a **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** useful life.[36] Also as indicated in NCSEA's Initial Comments, the EPRI TAG assumes a useful life of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** years. The Public Staff has not challenged DEC's and DEP's adjustment to extend the useful life. In the 2012 biennial avoided cost proceeding, the useful life of a CT was not a contested issue. Prior to the 2012 biennial avoided cost proceeding, DEC and DEP each assumed a shorter useful life than that which they have assumed in the instant proceeding.[37] Even though the Public Staff has not challenged the useful life adjustment in this proceeding, neither DEC nor DEP provided a reasonable basis for rejecting the useful life estimate of the CT used in the EPRI TAG, and, as a result, NCSEA recommends that the Commission direct DEC and DEP to assume the useful life set forth in the industry publication on which they relied, which is **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** years.

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[35] See NCSEA's Initial Comments, Section II.B.c (discussing contingency provisions in the Brattle Report, a study prepared by the engineering firm of Black & Veatch, and a study prepared by the United States Energy Information Administration).

[36] See NCSEA's Initial Comments, Section II.B.d.

[37] See NCSEA's Initial Comments, Section II.B.d.

2. DNCP

As noted in NCSEA's Initial Comments, in calculating the installed cost of a CT, DNCP relied, primarily, on the report titled Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, prepared for PJM Interconnection, LLC, prepared by The Brattle Group and Sargent & Lundy, dated May 15, 2014 (the "Brattle Report"). The Public Staff reviewed the adjustments made by DNCP to the installed cost of a CT set forth in the Brattle Report and took issue with DNCP's election to use a Siemens model CT in place of the GE Model 7FA CT that was utilized in the report.[38] For a number of reasons, the Public Staff questioned the likelihood that the Siemens model CT would actually be selected by DNCP for construction and, therefore, recommended that the Commission direct DNCP to recalculate its avoided capacity costs based on a GE Model 7FA CT or a comparable unit from a publicly available industry source.[39] In support of its position, the Public Staff noted that: 1) DNCP utilized a GE Model 7FA CT when calculating its avoided capacity cost in the 2012 biennial proceeding; 2) DNCP does not have a Siemens model CT in its fleet; 3) DNCP does not have experience with the construction and operation of a Siemens model CT; and 4) the combined cycle facilities recently placed into service or under construction by DNCP utilize Mitsubishi model CTs.[40] The Public Staff also pointed out that the Brattle Report prepared in 2012 and the Brattle Report prepared in 2014 utilize a GE Model 7FA CT, in

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[38] Public Staff's Initial Comments, p. 37.

[39] Public Staff's Initial Comments, p. 42.

[40] Public Staff's Initial Comments, pp 37-38.

part due to the fact that this is the predominant turbine type constructed in PJM territory.[41]

To underscore its concern, the Public Staff noted that DEC and DEP's projected installed cost of a CT, which is based on a GE Model 7FA CT, have increased by 2% since the 2012 filing while DNCP's projected installed cost has decreased by 36% from 2012, attributing this decrease primarily to DNCP's use of the Siemens model CT.[42]

NCSEA generally agrees with the Public Staff's appraisal of DNCP's CT adjustment and can find no clear need for the "swap." Accordingly, for the reasons set forth by the Public Staff and for the reasons set forth in NCSEA's Initial Comments, NCSEA recommends that the Commission direct DNCP to recalculate its avoided capacity cost using the GE Model 7FA CT.

To the extent that the Commission is not inclined to so direct DNCP, NCSEA: i) urges the Commission to reject the cost estimate provided by DNCP for the Siemens CT as the industry source for the estimate is out-of-date; and ii) supports the Public Staff's position that a number of related adjustments to the cost estimate are necessary.

DNCP utilized the CT cost estimate as published in the 2013 Gas Turbine World Handbook ("GTW Handbook") published by Pequot Publishing, Inc.[43] DNCP explained that the "GTW Handbook provides detailed cost and performance information on combustion turbine power plant equipment then currently available in the market" and that the handbook is "widely recognized in the power generation industry as one of the

[41] Public Staff's Initial Comments, p. 39.

[42] Public Staff's Initial Comments, p. 40, 42.

[43] DNCP's March 2015 Filing, Section III, pp 2-3.

best sources of current information on combustion turbine equipment cost and performance."[44] However, DNCP's reliance on the 2013 GTW Handbook should be scrutinized. As was pointed out during the 2012 biennial avoided cost proceeding, a DEC/DEP witness, in making the point that past CT costs should not be used as a means to measure the reasonableness of current CT cost estimates, noted—specifically with respect to the Siemens model CT—that despite predictions in the 2012 GTW Handbook that CT costs were rising, the CT costs indicated in the 2013 GTW Handbook declined by 15 percent.[45] Whether the 2013 GTW Handbook constitutes current data is questionable; beyond that issue, the fact that the cost estimate declined quite significantly between 2012 and 2013 raises the question of whether DNCP relied on this source because it provided a low cost estimate, particularly in light of the facts that DNCP does not have a Siemens model CT in its fleet and does not plan to add one.

With respect to the adjustments necessitated if the Commission is inclined to allow DNCP to "swap" in the Siemens CT, 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.[46]

With respect to contingency factor, as noted in NCSEA's Initial Comments, the reasonableness of a particular contingency factor varies, depending upon the specific context in which the factor will be used. A 5% to 10% contingency factor might be

[44] DNCP's March 2015 Filing, Section III, p. 3.

[45] See Rebuttal Testimony and Exhibits of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, Inc., N.C.U.C. Docket No. E-100, Sub 136, October 18, 2013, p. 15.

[46] Public Staff's Initial Statement, p. 37.

adequate for internal purposes at the late stages of the planning process, after completion of the final site selection process, after site-specific design documents have been prepared and once the final bid documents are about to be issued. But that same 5% to 10% contingency factor would not be adequate, even for internal purposes, during the earlier stages of the planning process. In the context of this proceeding, where the goal is to compensate for the risks borne by ratepayers throughout the entire planning, design and construction process, a higher contingency is necessary, consistent with the Commission's directive that the contingency factor reflect "a hypothetical plant in relatively early stages of planning."

If the Commission approves DNCP's use of the Siemens model CT, it must direct DNCP to recalculate its avoided capacity cost using a higher contingency factor that reflects the utility's inexperience with the CT. A contingency factor of 30%, which is the high end of the industry sources discussed in NCSEA's Initial Comments, would be clearly needed to appropriately reflect this lack of experience and the corresponding lack of ability to forecast construction and other risks with accuracy.

With respect to useful life of the CT, as noted in NCSEA's Initial Comments, the Brattle Report assumes a 20 year useful life. However, DNCP adjusted this component of the avoided capacity cost to 36 years,[47] which has the effect of reducing its avoided capacity cost projection. If the Commission approves DNCP's use of the Siemens model CT, it must direct DNCP to recalculate its avoided capacity cost using a shorter useful life, for the same reasons given earlier in the context of DEC and DEP. In the absence of any detailed studies concerning the useful life of a CT filed in this proceeding, NCSEA recommends that the Commission direct DNCP to assume the useful life set forth in the

[47] DNCP's March 2015 Filing, Section III, p. 1.

Brattle Report, which is 20 years. Furthermore, even if DNCP were to produce evidence concerning the lives of its existing GE model fleet, this would provide no basis for approximating the useful life of a CT model with which DNCP has no actual experience. Therefore, if the Commission permits DNCP to "swap" in a Siemens model CT in spite of the Public Staff's and NCSEA's recommendation otherwise, DNCP should be ordered to use the 20 year useful life assumed in the Brattle Report.

3. Calculating Rates

a. The weighting of avoided capacity costs between summer and non-summer months merits additional study and should be considered in a future proceeding

The Public Staff's Initial Comments point out that DEC and DEP have decreased the allocation for their summer (on-peak) months and increased the allocation for their non-summer (off-peak) months for both Option A and Option B avoided capacity rates, based on the utilities' historical CT production data. The Public Staff points out that DNCP has applied a similar allocation, also based on the utility's historical CT production data.[48] The Public Staff does not appear to take issue with the weightings used, though the Public Staff indicates that "continued use of a seasonal allocation of avoided capacity costs in the manner proposed by the utilities may need further review" and recommends that the Utilities provide similar CT production data in the next proceeding to determine whether the allocation remains reasonable.

NCSEA disagrees with the Public Staff's acceptance, even if only for this biennium, of the changed seasonal weightings. NCSEA urges the Commission to reject the change in allocation by the Utilities for the reasons pointed out in NCSEA's Initial Comments. Specifically, in the 2012 biennial avoided cost proceeding, the Commission

[48] Public Staff's Initial Statement, p. 43.

directed the Utilities to include in their avoided cost rate schedules an Option B, with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) as used by DEC at that time, in light of the settlement entered into between DEC, DEP and the Public Staff. With respect to DEP, the Commission found as follows:

> Subject to Commission approval, DEP may modify the number of hours and the weighting given summer and non-summer months used to calculate its Option A rates in this proceeding so as to make them more similar to DEC's. Following the completion of DEP's current review of its time-of-use rates, DEP should meet with the Public Staff to discuss those results before DEP proposes any changes to its Option B. In the event that DEP proposes a change to its Option B that increases the number of on-peak hours, the burden should be on DEP to show that the change is consistent with the goal of aligning the on-peak hours with the periods when DEP's customer demands and the value of capacity are the highest.[49]

In addition, during the first phase of this proceeding, after considerable discussion and presentation of evidence by all parties on the issue of adjusting the hours offered under Option B to better reflect the Utilities' needs, the Commission declined the parties' various requests to modify Option B, ultimately concluding that DEC, DEP and DNCP should continue to calculate and include in their avoided cost rate schedules an Option B, with the avoided capacity rates in Option B calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the Settlement Agreement entered into among DEC, DEP and the Public Staff in the 2012 biennial proceeding.[50]

Moreover, the Utilities' proposed seasonal weighting based on CT production data is inconsistent with the peaker method and, for this additional reason, should be

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[49] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, N.C.U.C. Docket No. E-100, Sub 136, February 21, 2014, Finding of Fact 11.

[50] Order Setting Parameters, pp 53-54.

rejected by the Commission. As was discussed at length in the first phase of this proceeding:

> The Commission has long approved the use of the peaker method for the purpose of establishing avoided costs and has repeatedly held that, according to the theory underlying the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. Stated simply, the fuel savings of a baseload unit will offset its higher capital costs, producing a net cost equal to the capital cost of a peaker. The Commission has further held that a CT is an appropriate proxy for the capacity-related portion of the total costs of a generating unit that might be added to the system in order to increase system capacity. Thus, <u>avoided capacity costs should equal the cost of a hypothetical CT and, together with the marginal system running costs, these will equal the cost of any generating plant, including a baseload plant</u>.[51]

While a CT has long been used as a proxy for peaking capacity in North Carolina when applying the peaker method, the theory underlying the peaker method, as recognized by the Commission, is that the capacity cost of the peaker plus the marginal system running costs equal the cost of any generating plant, including a baseload plant. As Public Staff witness Kirsch testified during the first phase of the proceeding, with respect to the peaker method, the strength of this method is that, in theory at least, the marginal capacity costs of all of a utility's resource investments are expected to equal one another in equilibrium, and, consequently, the quantitative result is not biased by the choice of one particular technology over another.[52] For this reason, the Utilities' seasonal weighting based on CT production data is inconsistent with the peaker method and should be rejected by the Commission. As indicated in NCSEA's Initial Comments, to

[51] <u>Order Setting Parameters</u>, p. 32 (emphasis added).

[52] In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014, N.C.U.C. Docket No. E-100, Sub 140, Transcript of Testimony Heard, July 10, 2014, Vol. 7, p. 96, ll 13-21.

the extent the Commission is willing to consider modifications to the definitions of on-peak and off-peak hours and allocation of capacity cost based on the Utilities' demand (and thus, potential for avoided cost), consideration should be deferred until a future proceeding when changes can be evaluated in a comprehensive manner to better tailor rates, and therefore induce QF generation, to the Utilities' needs.

III. Establishment of Commitment to Sell

Like NCSEA, the Public Staff has indicated support for the use of a simple form as a way to establish a QF's commitment to sell to the utility, for the purposes of establishing a legally enforceable obligation ("LEO"). NCSEA has worked with the Public Staff and the Utilities during the time between the filing of initial comments and the filing of reply comments to develop consensus on such a form. In general, NCSEA supports the form that has been developed jointly, which is filed as an exhibit to the reply comments of DNCP, with one exception. The form includes a section devoted to termination or expiration of the commitment. To date, neither the FERC nor the Commission has issued clear guidance on the issue of the point in time at which a commitment, or by extension a LEO, terminates or is no longer valid. Including such provisions in the form is premature, invites future dispute and complaint proceedings, and goes well beyond DNCP's stated objective of using a form "to determine the point in time at which a commitment occurs."[53] Therefore, NCSEA objects to including provisions in the form that effect the termination or expiration of the commitment.

In addition, in contrast to the Public Staff and the Utilities, NCSEA continues to maintain, as set forth in NCSEA's Initial Comments, that the form serve as one means,

[53] Order Setting Parameters, p. 63.

but not the exclusive means, for establishing a QF's commitment to sell. Mandating use of the form is wrought with peril, particularly if one objective is to avoid disputes and resort to complaint proceedings before the Commission. For example, mandating the use of the form could leave projects already under development, but without a PPA in place, in a position of uncertainty as to LEO date, possibly giving rise to a dispute. Consequently, in the interest of avoiding dispute and complaint proceedings, NCSEA stands by its position that the Commission incent the use of the form by holding that, on a prospective basis: a) a QF's use of the form will give rise to a rebuttable presumption in favor of the QF that it has committed itself to sell to the utility as of a date certain – i.e., the date a QF submits the form to the relevant utility; and b) a QF's failure to use the form will give rise to a rebuttable presumption in favor of the utility that the QF has not committed itself to sell to the utility.

It is NCSEA's understanding that the Public Staff intends to schedule additional discussions related to the form. NCSEA commits to participate in these discussions and to make a supplemental filing on this issue if necessary.

IV. QF Reporting Requirements

In the Public Staff's Initial Statement, the Public Staff expresses concern regarding DEC's and DEP's proposal in their respective power purchase agreements ("PPAs") that requires a QF larger than 100 kW in nameplate capacity to provide notice to the utility of annual, monthly, and day-ahead forecasted hourly production.[54] The Public Staff indicates that after consultation with DEC and DEP, the utilities have agreed to the following provision, in lieu of the initial proposal:

[54] Public Staff's Initial Statement, pp 54-55.

> Upon request, facilities larger than 3,000 kW may be required to provide prior notice of annual, monthly, and day-ahead forecast of hourly production, as specified by the Company. If the Seller is required to notify the Company of planned or unplanned outages, notification should be made as soon as known. Seller shall include the start time, the time for return to service, the amount of unavailable capacity, and the reason for the outage.

NCSEA recognizes that accurate production data is valuable for utility system operations and that the intent of the provision is to give the utility ample notice regarding QF production to allow the utility to plan and dispatch generation accordingly. For this reason, NCSEA does not oppose the reporting requirement as it relates to QF outages, planned or unplanned. However, NCSEA has concerns regarding the production forecast requirements agreed to by the Public Staff and DEC and DEP.

Accurate hourly production forecasts for QFs that rely on variable resources such as solar, wind and streamflow require sophisticated meteorological analysis. Moreover, the cost associated with production forecasting based on current, short term forecasts is prohibitive at this point in time for most small QFs. While the QF is in the better position to provide information regarding outages, the Utilities are in the better position to forecast production, given their meteorological capabilities and resources used to operate their systems. As the Utilities have superior forecasting resources and capabilities to those of the QF, the likelihood of reliance by a utility on production forecasts provided by a QF is very low. Because any benefits that may result from the requirement that a QF provide production forecasts are not commensurate with the burdens on a small QF, NCSEA recommends that the Commission reject the proposal as relates to production forecasting. However, in recognition of the value to the Utilities of accurate production forecasts, NCSEA recommends that the issue of production forecasting be revisited in a future proceeding at a point in time when the forecasting tools available to QFs have improved and become more cost effective, such that the disparity between the capabilities of the Utilities and the QFs has decreased and the likelihood that the QF production forecasts will be relied upon by the Utilities has increased.

Notwithstanding the foregoing, if the Commission is inclined to grant the request of Public Staff and DEC/DEP related to production forecasts, NCSEA requests that the Commission consider the following. QFs routinely develop hourly production projections as part of the design/development process, which are based on the specific design location of a specific site and long-run, average meteorological data from a local meteorological station. Because they are based on long-run, average data, these projections may not be as accurate as projections based on short-run, current data. For these reasons and for the reasons given above, NCSEA strongly recommends that the proposal be further revised to make clear that a QF may rely on the production forecasts produced during the design/development process to fulfill its obligations under the contract provision and that any inaccuracy in the forecasts shall not give rise to a right to terminate by the respective utility. To this end, NCSEA proposes the following, as an alternative to the proposal of the Public Staff and DEC/DEP, with respect to production forecasts:

> Upon request, facilities larger than 3,000 kW may be required to provide prior notice of annual, monthly, and day-ahead forecast of hourly production. The forecasts of production developed during the design and development process of the Facility may be used by the Seller to satisfy its obligations hereunder. Any inaccuracies in the forecasts of production shall not give rise to a right to terminate the Agreement by Company.

V. DEC's and DEP's Power Factor Requirements

As indicated in NCSEA's Initial Comments, DEC's and DEP's proposed rate schedules include provisions related to reactive power.

Specifically, DEC's proposed rate schedule includes a provision, labeled "Power Factor Correction," pursuant to which DEC proposes to reduce the number of kWh for which payment is made by the utility if the "average power factor" of the QF falls outside the parameters specified in the rate schedule without any commensurate credit to the QF when it produces reactive power (measured in volt-ampere-reactive or "VAR") that benefit DEC.

Similarly, DEP's proposed rate schedule includes a provision pursuant to which DEP proposes to bill the QF at a rate of $0.34 multiplied by the number of kilo-VARs consumed or supplied by the QF. DEP's rate schedule contemplates that a QF may enter into an "Operating Agreement" with the utility to adjust VAR production to support voltage control. However, as DEP's standard offer documents are silent as to the referenced "Operating Agreement," it is not clear how a QF requests the right to enter into such an agreement and what the terms and conditions of the agreement would be.

Paragraph 4(a) of the proposed Terms and Conditions for the Purchase of Electric Power ("Terms and Conditions") for both DEC and DEP require the QF to operate at a "power factor of approximately unity" without consuming VARs produced by the utility.

Paragraph 8(b) of the Terms and Conditions requires the QF to be operated "in such a manner as to generate reactive power as may be reasonably necessary to maintain voltage levels and reactive area support as specified by the Company. Any operating requirement is subject to modification or revision if warranted by future changes in the distribution or transmission circuit conditions." This provision appears to give the utility the unilateral right to modify operating requirements at any time, which could affect the QF's production.

Section 1.8 of the North Carolina Interconnection Agreement,[55] provides as follows:

> 1.8 Reactive Power
>
> 1.8.1 The Interconnection Customer shall design its Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Utility has established different requirements that apply to all similarly situated generators in the control area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.
>
> 1.8.2 The Utility is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Generating Facility when the Utility requests the Interconnection Customer to operate its Generating Facility outside the range specified in Article 1.8.1 or the range established by the Utility that applies to all similarly situated generators in the control area. In addition, if the Utility pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.
>
> 1.8.3 Payments shall be in accordance with the Utility's applicable rate schedule then in effect unless the provision of such service(s) is subject to a regional transmission organization or independent system operator FERC-approved rate schedule. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb reactive power under this Agreement, the Parties agree to expeditiously file such rate schedule and agree to support any request for waiver of any prior notice requirement in order to compensate the Interconnection Customer from the time service commenced.

NCSEA understands that section 1.8.1 of the North Carolina Interconnection Agreement is intended to be a design criteria, rather than an operating criteria, and makes clear that, all generation must be designed to operate with a power factor range of 95%

[55] The North Carolina Interconnection Agreement was approved by the Commission on May 18, 2015 in N.C.U.C. Docket No. E-100, Sub 101.

leading to 95% lagging. Not clear to NCSEA is whether this design criteria will allow a QF to operate at a "power factor of approximately unity" without consuming VARs produced by the utility, as required by Paragraph 4(a) of the Terms and Conditions or whether this criteria will allow a QF to operate "in such a manner as to generate reactive power as may be reasonably necessary to maintain voltage levels and reactive area support as specified by the Company[]" as required by Paragraph 8(b) of the Terms and Conditions. Additionally, DEC and DEP reserve the unilateral right to modify operating requirements at any time, which has the potential to adversely affect the production of the QF. And, as previously noted, both DEC and DEP reserve the right in their respective rate schedules to penalize the QF monetarily for failure to maintain a specified power factor. To the extent that the Commission allows DEC and DEP to penalize a QF monetarily for failure to comply with a standard set forth in the standard offer documents, that standard must be clear and unambiguous. As currently drafted, the provisions related to power factor are neither clear nor unambiguous.

In addition, read together, the North Carolina Interconnection Agreement and the DEC and DEP Terms and Conditions appear to contemplate that the QF and the utility may agree to enter into a separate agreement, pursuant to which the QF may be paid by the utility for reactive power supplied or absorbed. However, such an arrangement is only hinted at in the various documents; there is no explanation of when a QF is eligible to enter into this type of agreement or the terms and conditions of such an agreement. While NCSEA does not necessarily oppose this type of arrangement, DEC's and DEP's proposed rate schedules and Terms and Conditions lack the specificity necessary for meaningful analysis by NCSEA.

For this reason, in the interest of clarity and minimizing potential for dispute, NCSEA recommends that the Commission direct DEC and DEP to establish a clear standard related to power factor in either the Terms and Conditions or in the rate schedule and strike all other provisions.

CONCLUSION AND RECOMMENDATIONS

NCSEA respectfully requests that the Commission take the foregoing reply comments and recommendations into consideration in this docket.

Respectfully submitted this the 7th day of August, 2015.

LAW OFFICE OF CHARLOTTE MITCHELL, PLLC

/s Charlotte A. Mitchell
NC Bar #34106
Law Office of Charlotte Mitchell, PLLC
PO Box 26212
Raleigh, North Carolina 27611
Telephone: (919) 260-9901
E-mail: cmitchell@lawofficecm.com

ATTORNEY FOR NCSEA

CERTIFICATE OF SERVICE

The undersigned certifies that she has served a copy of the foregoing **REPLY COMMENTS BY NCSEA** upon the parties of record in this proceeding, or their attorneys, by electronic mail.

This 7th day of August, 2015.

/s Charlotte A. Mitchell

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