STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	**DUKE ENERGY CAROLINAS, LLC'S**
Biennial Determination of Avoided	)	**AND DUKE ENERGY PROGRESS,**
Cost Rates for Electric Utility	)	**LLC'S PROPOSED ORDER**
Purchases from Qualifying Facilities -	)	**ESTABLISHING STANDARD RATES**
2014	)	**AND CONTRACT TERMS FOR**
	)	**QUALIFYING FACILITIES**

HEARD: Tuesday, May 19, 2015, at 9:30 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown Bland, Presiding; Chairman Edward S. Finley, Jr., and Commissioners Don M. Bailey, Bryan E. Beatty, Jerry C. Dockham, James G. Patterson and Susan W. Rabon

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BY THE COMMISSION: These are the current biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the Federal Energy Regulatory Commission's ("FERC") regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings are also held pursuant to the responsibilities delegated to this Commission under N.C. Gen. Stat. § 62-156(b) to establish rates for small power producers as that term is defined in N.C. Gen. Stat. § 62-3(27a).

Section 210 of PURPA and the regulations promulgated thereto by the FERC prescribe the responsibilities of the FERC and of State regulatory authorities, such as this Commission, relating to the development of 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 and small power production facilities that meet certain standards and are not owned by persons primarily engaged in the generation or sale of electric power 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. For such purchases, electric utilities are required to pay rates which 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 relevant 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 regulation, the FERC delegated the implementation of these rules to State regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules.

The Commission has implemented 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 subject to the Commission's jurisdiction to the QFs with whom they interconnect. The Commission has also reviewed and addressed other matters involving the relationship between the electric utilities and QFs, including terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also results from the mandate of N.C. Gen Stat. § 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 in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The definition of the term "small power producer" as used in N.C. Gen Stat. § 62-156 is more restrictive than the PURPA definition of that term, in that N.C. Gen Stat. § 62-3(27a) includes only hydroelectric facilities of 80 MW or less, thus excluding other types of renewable resources.

On February 25, 2014, the Commission issued its *Order Establishing Biennial Proceeding and Scheduling Hearing* ("Scheduling Order"). 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 rates 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, particularly capacity payments, including, but not limited to, whether a 2.0 performance adjustment factor ("PAF") for run-of-river hydroelectric facilities with no storage capability should be continued, whether avoided capacity payments are more appropriately calculated based on installed capacity rather than a per-kWh capacity payment, and whether the methods historically relied upon by the Commission to determine avoided cost capture the full avoided costs. Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP")," formerly known as Duke Energy Progress, Inc.), 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; scheduled an evidentiary hearing for July 7, 2014; 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, responsive testimony be filed by May 30, 2014, and rebuttal testimony by June 20, 2014.

The following parties filed timely petitions to intervene that were granted by the

Commission: the North Carolina Sustainable Energy Association ("NCSEA"); the Carolina Utility Customers Association, Inc. ("CUCA"); the Carolina Industrial Customers for Fair Utility Rates I, II, and III ("CIGFUR"); the North Carolina Waste Awareness and Reduction Network ("NC WARN"); the Environmental Defense Fund ("EDF"); the Southern Alliance for Clean Energy ("SACE"); the North Carolina Hydro Group ("NC Hydro Group"); The Alliance for Solar Choice ("TASC"); the Public Works Commission of the City of Fayetteville; the North Carolina Chapter of the Sierra Club and the Natural Resources Defense Council ("Sierra Club/NRDC"); and Google, Inc. The Public Staff's participation is recognized pursuant to North Carolina statute.

DEC, DEP, DNCP, EDF, NCSEA, NC Hydro Group, NC WARN, SACE, TASC and the Public Staff filed direct, supplemental and responsive testimony, and their witnesses presented evidence at the hearing July 7, 2014 through July 10, 2014. Following the evidentiary hearing, the Commission issued an *Order Setting Avoided Cost Parameters* ("Phase One Order") on December 31, 2014. The Phase One Order, among other things, established certain parameters by which avoided cost rates should be calculated and required that DEC, DEP, DNCP, WCU and New River file proposed avoided cost rates 60 days from the issuance of the Order (by March 2, 2015). The Phase One Order resolved several outstanding issues, ending the first phase of the proceedings.

On January 8, 2015 the Commission issued its *Order Establishing Procedural Schedule and Scheduling Public Hearing* ("Procedural Order"). The Procedural Order stated that the Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits and schedules rather than a full evidentiary hearing. DEP, DEC, DNCP, New River and WCU were required to file their statements and exhibits by March 2, 2015. Other persons desiring to become parties were initially required to seek permission to intervene and to file their comments, statements, and exhibits by May 4, 2015; this deadline was subsequently extended to June 22, 2015. All parties were allowed to file reply comments by June 8, 2015; this deadline was subsequently extended to August 7, 2015. All parties were allowed to file proposed orders by July 6, 2015; this deadline was subsequently extended to September 18, 2015. The Commission scheduled a public hearing for May 19, 2015, solely for the purpose of taking non-expert public witness testimony. Finally, the Commission required DEP, DEC, DNCP, New River and WCU to publish notice and submit affidavits of publication no later than the date of the hearing.

On January 28, 2015, DEC and DEP (collectively, the "Companies") filed a joint petition for clarification of the Commission's holding related to the application of Finding of Fact No. 5 in the Phase One Order to bilateral negotiations with large qualifying facilities that are not eligible for standard rates and contracts. On February 2, 2015, NCSEA responded to the joint petition for clarification. On March 6, 2015, the Commission issued its Order of Clarification.

On March 2, 2015, DEP, DEC, DNCP, WCU and New River filed statements, comments and/or exhibits in accordance with the Commission's Scheduling Order.

On or before May 13, 2015, all electric utilities filed Affidavits of Publication of the Notice of Hearing, and the public hearing was held in the Commission's hearing room as scheduled. Two public witnesses gave testimony at that hearing. In addition, several consumer statements of position were filed in this docket.

On June 22, 2015, the Public Staff, NCSEA and SACE filed initial comments.

On August 7, 2015, reply comments were submitted by the Public Staff, DNCP, NCSEA, SACE and jointly by DEP and DEC. NCSEA also filed the affidavit of consultant Ben Johnson.

On September 10, 2015, the Public Staff filed a letter on the status of the negotiations on the standard form for providing a Notice of Commitment to Sell.

On September 17, 2015, DEC and DEP filed a Letter and two attachments, stating that DEC, DEP, and DNCP had reached agreement on the proposed Notice of Commitment to Sell and providing draft Notice of Commitments to Sell to the Commission.

Also on September 17, 2015, the Companies filed a letter outlining a settlement on certain provisions of DEC's and DEP's standard offerings with NCSEA.

On September 18, 2015, proposed orders were filed by the parties.

Various filings were made and orders were issued which are not discussed in this order but are included in the record of the proceeding.

Based on the foregoing, all of the parties' comments and other filings, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

<u>Avoided Energy Costs</u>

1. The Companies appropriately removed unknown and speculative costs related to carbon emission compliance from their base expansion plans from their 2014 IRPs in calculating their avoided energy costs.

2. The Companies' fuel forecasts are reasonable and appropriate for use in calculating avoided energy costs.

3. In developing the energy component of their avoided cost rates, DEC and DEP appropriately recognized the economic benefits associated with purchases of renewable energy.

Avoided Capacity Rates

4. In developing the capacity component of their avoided cost rates, DEC and DEP appropriately relied on information from Energy Power Research Institute ("EPRI"), which complied with the Commission's directive to use publicly available data and appropriately accounted for economies of scale while excluding economies of scope.

5. DEC's and DEP's proposed contingency adder is based on the Companies' experiences in constructing and operating Combustion Turbines ("CTs") in the Carolinas and, accordingly, it is reasonable and appropriate to use in calculating the installed cost of a CT.

6. The Companies' estimate of a useful life is based on the Companies' experience and expertise in constructing and operating CTs in the Carolinas, and, accordingly, the estimate is reasonable and appropriate to use in calculating the installed cost of a CT.

Calculation of Rates

7. DEC's and DEP's proposed seasonal weighting factors are justified, reasonable and appropriate.

Standard Terms and Conditions, the Purchase Power Agreement, and Schedule PP

8. The Companies' provisions that define the applicability of Schedule PP are long-established and consistent with the Commission's five MW eligibility threshold.

9. The Companies' Reduction in Contract Energy Charge and Reduction in Contract Capacity Charge protect ratepayers and are justified, reasonable and appropriate.

10. The Companies' provisions on the assignment of purchase power agreements ("PPAs") protect ratepayers and are justified, reasonable and appropriate.

11. The Companies' provisions in their Standard PPAs are consistent with prior Commission precedent concerning the effect of government action and changes in law.

12. The Companies' proposed adjustments for reactive power are reasonable and appropriate.

13. The Companies' single, contiguous premise provision is consistent with well-established retail service practices and is justified, reasonable, and appropriate.

14. The Companies' reporting requirements, as recommended by the Public Staff, are reasonable and appropriate.

Issues Relating Standard Terms and Conditions, the Purchase Power Agreement and Schedule PP that Have Been Resolved by NCSEA and the Companies

15. The Commission finds that the provisions agreed upon by NCSEA and the Companies are reasonable and appropriate for inclusion in the Companies' Standard PPA, Terms and Condition and Schedule PP.

Notice of Commitment to Sell

16. The Notice of Commitment to Sell Forms submitted by DNCP and the Companies, respectively, are reasonable and should be approved.

Affidavit of Ben Johnson, PH.D

17. The affidavit of Ben Johnson, PH.D filed in support of NCSEA's Reply Comments is improperly filed and, therefore, the Commission will not consider it its determinations on these issues.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

In their Initial and Reply Comments, both the Public Staff and NCSEA assert that the Companies did not comply with the Phase One Order when they removed the costs of CO_2 from their generation expansion plan in order to calculate their avoided energy costs. Both the Public Staff and NCSEA request the Commission to direct DEC and DEP to recalculate their energy rates using a generation expansion plan that does not include the costs of CO_2. Both argue that inclusion of the cost of carbon emissions control in its generation expansion plan may result in the selection of new nuclear units, which provide low cost energy, which may result in an under-estimation of avoided fuel costs.

In their Reply Comments, the Companies noted that they had complied with the Commission's Phase One Order by removing all but the known and quantifiable costs from their generation plans. In Phase One, the Public Staff and NCSEA had emphasized that the Companies must develop a long-term resource plan that is robust and accounts for the possibility that carbon costs may be imposed in the future. The Companies noted, however, that PURPA requires them to calculate avoided costs based on currently known and measurable costs that are avoided because of the purchase of power from the QF. The Companies argued that they had complied with both requirements in the avoided cost filing. The expansion plans utilized for the March 2 filings are the same as the expansion plans developed in the base case of the 2014 IRPs. The exception, however, is that carbon costs were removed in compliance with the Phase One Order.

<u>Conclusion</u>

Based on its review of the comments filed by the parties, the Commission finds that the Companies have appropriately excluded the costs of carbon emissions control from their calculation of avoided energy costs. As the Commission noted in its "Discussion And Conclusions" in its Phase One Order, "[w]hile the [Environmental Protection Agency] EPA has proposed to regulate CO_2 under the Clean Air Act and the utilities have included forecasted costs in IRP scenarios, the costs are not sufficiently certain to be included in avoided costs at this time."[1] As the Phase One Order's Discussion and Conclusions on this issue further provide, the inclusion of assumed carbon costs in the IRPs and the exclusion of such costs in avoided cost production models have existed for several years and result from the different purposes of the two proceedings and the different methods utilized for each process.[2] Therefore, the Commission concluded that, "in the present case, . . . it is inappropriate for ratepayers to shoulder such costs until they become known and verifiable."[3]

The Companies appropriately removed the costs of carbon emission compliance from that base plan to calculate their avoided energy costs, consistent with the Phase One Order. The recently released EPA Clean Power Plan ("CPP") supports the Commission's decision on this issue. The CPP has no prescribed CO_2 tax, but instead sets state-specific volumetric limits. As such, it is entirely possible that under the CPP, the Companies would replace retiring nuclear generation with new nuclear generation to meet the volumetric limits without the explicit imposition of a carbon tax. Therefore, based on the foregoing, the Commission finds the arguments of the Public Staff and NCSEA to be unpersuasive, and thus, concludes the Companies have complied with the Phase One

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[1] Phase One Order at 44.
[2] Id.
[3] Id.

Order and appropriately removed speculative and unknown costs from their base generation plans, as filed in their IRPs in 2014.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

In their Initial Comments, NCSEA and the Public Staff both asserted that the Companies employed "a different method" to construct their natural gas price and coal price forecasts for their March 2015 avoided cost filings. Specifically, NCSEA contended that the Companies understated their avoided energy costs by giving greater emphasis to futures market prices throughout the first 10 years of the 15-year time horizon. NCSEA alleged that this effectively ignored the possibility that prices might be nearing the bottom of a cyclical downturn and might swing sharply higher to move back toward, or even above, the long-term trend line of prices. NCSEA also noted that DEC's witness in the previous year's (2014) fuel rider proceeding had testified that there was a much higher probability of an upswing in gas prices than a downswing just because of where future market prices are.[4] NCSEA also accused the Companies of ignoring the possibility that spot prices may be a "temporary aberration."[5] Finally, NCSEA warned that the Companies had greatly increased the risk that the actual costs they incur when producing electricity using their own generating units will be substantially higher than their avoided energy estimates.

NCSEA also criticized the Companies using a different method to estimate future gas prices in the avoided cost proceeding than they had used in the 2014 IRPs and that DEP had used in its Sutton Blackstart CT ("Sutton CT") application for a certificate of convenience and public necessity ("CPCN"). Had they used the methods employed in

[4] NCSEA Initial Comments at 9.
[5] NCSEA Initial Comments at 11.

the 2014 IRPs, NCSEA concluded, the proposed avoided cost energy rates paid to QFs would have been higher.

The Public Staff echoed NCSEA's concerns about the Companies' fuel forecasts resulting in avoided energy costs that were unreasonably low. The Public Staff also alleged that the method the Companies used to estimate future fuel prices was different than the one they used for the 2014 IRP filings in Docket No. E-100, Sub 141. The Public Staff explained that the change in methodology was marked by the Companies using current forward prices for coal and natural gas over a larger portion of the planning period - from five years to ten years - before shifting to long-term fundamental forecasts. The Public Staff again suggested that the avoided cost filing should use the same inputs and methodologies as the Companies use in their IRPs. It also highlighted the 2002 Biennial Proceeding, Docket No. E-100, Sub 96, in which it has convinced the Commission that DEP's natural gas price forecast was "overly conservative," and the Commission had directed DEP to recalculate its avoided energy rates to reflect a "realistic long-term forecast of its natural gas prices."[6]

The Public Staff acknowledged that, in previous avoided cost dockets, it had supported the use of forward prices as a component in the development of near-term forecasts as they transition to the long-term. It recounted that, prior to 2012, DEC incorporated two-year forward prices combined with a long-term fundamental natural gas price forecast in developing its IRP. In their 2014 IRPs, DEC and DEP incorporated five years of future prices with their long-term forecasts. In this filing, however, the Companies incorporated ten years of forward data for natural gas. In these avoided cost filings, however, the Companies incorporated ten years of forward data, which the Public

[6] Public Staff Initial Comments at 29.

Staff characterized as an "over-reliance" on forward data that called into question the reliability of the forecasts. The Public Staff also expressed concern that the use of this forward data "actually lowers avoided energy costs."[7] Therefore, the Public Staff urged the Commission to direct the Companies to revert to the use of five years of "ask prices," instead of ten years, which will result in natural gas price forecasts that are higher, according to the Public Staff's comparison of DEC's natural gas price forecasts with five years of ask prices and ten years of natural gas prices. The Public Staff also recommended that the Commission require DEC and DEP to recalculate their avoided energy costs using the reconstructed forecasts.

In its Reply Comments, NCSEA recounted its prior comments, but also noted that approval of understated avoided energy costs will discourage QF development and ratepayers will bear the risk and burden of paying for electricity generated by DEC and DEP at a cost far in excess of the avoided costs they estimated in this proceeding. NCSEA also noted that the Companies are procuring natural gas based on a five-year usage forecast, which forecasts fuel prices over a five year horizon. NCSEA then implied that DEC's and DEP's use of ten years of future market data was purposefully chosen to drive down avoided energy cost calculations. NCSEA did not take issue with the use of five years of futures market data, as opposed to ten; however, it recommended that the Companies use their actual 2014 IRP fuel forecasts to recalculate their avoided energy costs.

NCSEA acknowledged that the Commission has stated that the utilities should use "up-to-date data in determining inputs" for avoided cost rates, and that the 2014 IRP fuel forecasts were developed prior to September 2014. Despite the lapse in time, however,

[7] Public Staff Initial Comments at 33.

NCSEA argued that the Companies had used IRP data to support an application for the Sutton CT and to calculate future fuel savings to DEP customers when the Companies acquired ownership interests in the North Carolina Eastern Municipal Power Agency generating facilities. Therefore, the Companies should use the same fuel forecasts for calculating avoided cost rates.

In its Reply Comments, the Public Staff again acknowledged that the Utilities have used futures market data in both of its last two IRPs and avoided cost proceedings and that "[s]ome use of futures market data might be appropriate for the short-term, but only to the extent that the markets are viewed as liquid and the volumes being transacted reflect an active market for the commodities in question."[8] The Public Staff asserted that there was insufficient liquidity in the market, however, to support the amount of futures market data the Companies used here because of the relatively small number of contracts for coal futures and natural gas contracts.

The Public Staff reiterated its position that the inputs and assumptions used for the IRP docket be the same as those used in avoided cost docket. Therefore, the Public Staff recommended that the Companies recalculate their avoided energy costs using the same fuel forecast weightings as used in the 2014 IRPs and that if the Companies wish to adjust the way they utilize forward prices and long-term forecasts in proceedings before the Commission, they make those proposals in the biennial IRP proceedings.

SACE also filed Reply Comments on this issue consistent with the Public Staff's and NCSEA's criticisms of the Companies' fuel forecasts, but, contrary to the Public Staff's recommendation, SACE recommended that the Companies use only three years of NYMEX Henry Hub natural gas futures prices and then transition to long-term forecasts

[8] Public Staff Reply Comments at 2.

when calculating avoided energy costs. SACE argued that a natural gas futures price is the price one would pay today to procure natural gas at the Henry Hub at a specific date in the future.

In their Reply Comments, the Companies explained that their methodology for forecasting fuel prices had not changed. Under their methodology, the Companies update fuel prices during the year by using market data where market data is liquid – that is, where transactional prices are available from market prices. Market prices represent the price willing buyers and sellers agree to transact at a future point in time. When market data is not observable, the Companies stated that a modeled forecast was the best alternative. The Companies further stated that in the 2014 IRPs, they used market data for the first five years and the fundamental fuel forecast was used for the longer-term fuel prices. In this case, however, the Companies reported that increased liquidity in the market justified the Companies' use of increased years of market data before transitioning to the fundamental forecast for longer term prices. Thus, the Companies concluded, the methodology did not change, the market liquidity did.

The Companies then described the natural gas market over the past decade, noting that volumes of natural gas have risen significantly over the past decade, driven primarily by an increase in shale gas production in the United States. This expansion has resulted in multiple buyers and sellers of natural gas in the market that are willing to enter into ten-year transactions. To update its fuel forecasts prior to filing its proposed avoided costs, the Companies requested quotes from four different financial institutions for 20,000 MMBtu/day natural gas each from 2016 to 2025. The nominal value of the bids received from those financial institutions was more than $1.1 billion over ten years. The

Companies concluded that, based on these received quotes, the ten-year market for natural gas was liquid, and, therefore, reasonable for use in the calculation of avoided energy rates.

The Companies also addressed NCSEA's claims that they were inconsistent in their usage of market data to prepare fuel forecasts. First, with respect to DEP's application for a CPCN for the Sutton CT, the Companies noted that they did not rely upon the same fuel forecasting that DEP had used in the 2014 IRP to justify the Sutton CT. The process for applying for a CPCN at the Commission requires the inclusion of the applicant's IRP, which contains the fuel forecast; however, the Companies asserted that DEP did not use the fuel forecasts to justify the Sutton CT. Instead, the Companies referred to the testimony of witness Snider that gas prices have a limited impact on DEP's use or dispatch of assets for operational support. The Sutton CT was intended for reliability and system capacity support.[9]

The Companies further discounted NCSEA's assertions that they were otherwise inconsistent with their fuel forecasts. The Companies rely on the market to determine whether price transparency and liquidity exist. This is determined by whether there are willing buyers and sellers and whether there is a reasonable spread between the bid and ask price. Thus, the Companies concluded that their forecasting approach is fully consistent with their past practices of using market data to the extent available, and then using price projections for the remainder.

The Companies also disagreed with the Public Staff's view that the market for "forward" deliveries suddenly becomes illiquid after five years. The Companies explained that the Public Staff's statement that the market for ten-year futures is

[9] Direct Testimony of Glen A. Snider, Docket No. E-2, Sub 1066, filed April 15, 2015, at 8-9.

relatively illiquid is not relevant to the issue at hand because the Companies do not obtain ten-year deliveries using a ten-year futures contract, and it is incorrect to assume that liquidity decreases due to fewer market participants over the five-year to ten-year period, relative to the number of participants over a five-year period. The Companies noted that a reduction in futures contracts over the five- to ten-year period instead shows that at this time, fewer market participants are using long-dated futures contracts, not that the market is illiquid. The reliable indicator of a natural gas price in the future, instead of the price of futures contracts, is the price of a forward transaction quoted by a willing seller to a willing buyer, according to the Companies. The Companies further argued that if the market were illiquid, then they would not have been able to obtain the multiple prices within the narrow spreads.

The Companies concluded by noting that the United States and North Carolina have benefitted from increased supply and lower prices for natural gas, which is driving market liquidity over a longer time horizon. They disputed the contention that the fact that prices are low now means that the prices are inaccurate or unreliable. QFs have benefitted from higher natural gas prices being used to calculate avoided costs, which were incorporated into the rates paid to QFs when their contracts were put into place, even though natural gas prices have decreased sharply, according to the Companies. Citing current market projections as of August 6, 2015, the Companies observed that market prices have been lower than the fuel projections used to calculate avoided energy rates in avoided cost dockets since 2006. Furthermore, the Companies noted that the market was approximately 5% lower at the time of the Reply Comments than when the Companies prepared their proposed rates, negating NCSEA's contention that the prices used to calculate the rates were not at the bottom of a cycle. Because ratepayers have benefitted from lower natural gas prices as part of the Companies' native load generation, the Companies contended that their customers should likewise benefit here from the actual lower natural gas prices and the increasing supply in the marketplace.

Conclusion

The Commission recognizes that the supply of natural gas has increased and the price of natural gas has decreased over the past several years. North Carolina customers have benefitted from that decrease in prices as the lower prices are reducing the Companies' actual fuel expenditures. The Commission does not agree with NCSEA that natural gas prices are understated because they not reach the long term trend line of gas prices. As noted by DNCP, historical gas prices are not relevant in the avoided energy cost context. Avoided energy costs are based on forward-looking estimates, not on historical trend lines that have little bearing on the natural gas market today or in the future.[10] The Commission believes that the Companies' avoided energy cost ought to reflect realistic natural gas prices under PURPA.

As witness Snider testified in the Phase One hearing, QF contracts represent long-term fixed price obligations on behalf of DEC's and DEP's customers based largely on forecasts of future fuel prices.[11] A goal of PURPA is to make ratepayers indifferent between a utility self-build option, alternative purchase, or a purchase from a QF. Entering into a ten-year contract to purchase energy from a QF should be no different than purchasing natural gas ten years out into the future to fuel a CT or combined cycle. Therefore, the Companies' fuel forecasts used to calculate avoided energy costs should

[10] DNCP's Reply Comments at 24.
[11] Supplemental Direct Testimony of Glen A. Snider, filed May 30, 2014; Tr. vol. 1 at 219, ll 18-20.

align as closely as possible to actual future fuel prices. As noted otherwise, ratepayers are paying in excess of the Companies' avoided costs, contrary to the indifference standard of PURPA.

The record shows that the Companies have consistently used future market data in their fuel forecasts included in their IRPs and previous avoided cost proceedings. DEC incorporated *two-year* forward prices combined with a long-term fundamental natural gas price in developing its 2012 and 2013 IRPs. As the natural gas market became more liquid, DEC and DEP incorporated *five years* of future prices with their long-term forecasts in their 2014 IRPs. At that time, after five years, market data was less liquid. They also used five years of market prices followed by long-term fundamental prices in years six and beyond in the Sutton CT proceeding, in Docket No. E-2, Sub 1066.[12] Therefore, the Companies have not changed their methodology but have simply and appropriately adjusted the number of years of market prices in their methodology as market conditions have warranted. In the Commission's view, as more supply becomes available, more liquidity should be expected.

The question then is whether the market is sufficiently liquid to support the Companies' incorporation of ten years of market data. The Commission believes it is. The volume of natural gas supply has increased, as unchallenged testimony in DEC's most recent, (2015) Fuel Charge Adjustment proceeding showed:

> the development of shale gas has created a fundamental shift in the nation's natural gas market. In recent years, improvements in production technologies have allowed greater access to the natural gas trapped in shale formations, resulting in increased reserves that can product natural gas more quickly and economically. Given continued production increases, natural gas prices continue to remain at lower levels.[13]

[12] Direct Testimony of Glen A. Snider for Duke Energy Progress at 8.
[13] Order Approving Fuel Charge Adjustment, Docket No. E-7, Sub 1072, at 13.

In addition, the record in this proceeding shows that, by obtaining actual and multiple bid-ask quotes that could be transacted with, the Companies have demonstrated that sophisticated market-suppliers are ready, willing, and able to enter into ten-year transactions. The fact that multiple prices are being obtained with narrow price spreads means there is liquidity in the market in the forward contracts market over a ten-year period. If the market were illiquid, the Companies would not have been able to obtain multiple prices within narrow spreads. Thus, the liquidity of the market supports the use of ten years of market data, just as it formerly supported use of only two years and then five years of market data. In other words, the market has changed, but the Companies' methods have not.

The Commission also rejects the argument that the Companies must be required to replicate their IRP filings in their avoided costs filings, no matter how much time has elapsed between the two. The Commission first notes that at the time of the filing of the proposed orders, the Companies had already filed their 2015 IRPs, and those IRPs contained fuel forecasts based on ten years of market data, like those in the Companies' March 2, 2015 avoided cost filings in the avoided cost case. The avoided cost rates that the Commission approves in this proceeding will be approved closer in time to the filing of the 2015 IRPs than the 2014 IRPs, which were filed more than a year before the proposed orders were filed. This could lead to avoided cost that are stale and no longer representative of the Companies' actual avoided costs. Therefore, the avoided cost filings and the current IRPs are consistent with respect to the use of market data in the forecasts. The Commission has previously directed in the Order on Clarification issued in this docket on The Public Staff further recommended that the Companies introduce any change they want to make in forecasting their fuel prices in their IRPs first, before including them in the avoided cost dockets. The Commission finds the Public Staff's suggestion problematic for the following reasons. First, "the main purpose of the annual IRP proceeding is planning."[14] This is why DEP included its IRP in its Sutton CT proceeding. It is well-established that the IRP is intended to be "akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific projects at a later time."[15] The IRP is not intended, however, as a procedure where the Commission issues specific directives on the Utilities' operations. Therefore, it is unclear from the Public Staff's recommendation whether the Commission would be required to make specific findings on the reasonableness and acceptability of certain inputs in the IRPs prior to the Utilities including them in their avoided cost filings or whether other parties would have to assess and comment on the IRP filings' potential impact on upcoming avoided cost proceedings during the actual IRP proceedings, or be deemed to have waived the issue.

In contrast, the purpose of the PURPA proceeding is to determine the rates to be paid to QFs and to ensure that those rates are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against co-generators or small power producers.[16] The Commission agrees that in most cases in the past, the IRPs will be filed much closer in time to the filing of proposed avoided cost rates, and, therefore,

[14] *Order Adopting Amendments to Commission Rule R8-60*, Docket No. E-100, Sub 111, issued July 20, 2015 at 27.
[15] *Id.*, citing *State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation*, 105 N.C. App. 136, 412 S.E.2d 166.
[16] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 136, issued Feb. 21, 2014 at 3.

the inputs and assumptions should be very similar. The Commission notes in the 2012 avoided cost proceeding, however, DEP used a higher natural gas fuel forecast than it used in its 2012 IRP. This change resulted in *an increase* in DEP's avoided cost rates by approximately 4%.[17] Neither the Public Staff nor NCSEA, however, requested that DEP re-calculate its forecasted fuel prices (which would have resulted in lower avoided cost rates) to maintain consistency with DEP's 2012 IRP, however. Therefore, the Commission finds that although consistency with the IRP is sometimes desirable and appropriate, certain circumstances, such as a lapse of time and changes in the market, may justify departing from the inputs and assumptions included in the IRPs. As such, the Commission declines to require the Companies to recalculate their avoided energy costs simply to have the Companies' fuel forecasts align more with last year's, as opposed to this year's, IRPs.

Finally, the Commission recognizes that QFs have benefitted in the past from natural gas price projections that were higher than actual prices, thereby resulting in QFs being paid over long-term contracts, in excess of the Companies' actual avoided costs. As noted by the Companies in their Reply Comments, market prices have been lower than the fuel projections used to calculate avoided energy rates in the avoided cost dockets since 2006.[18] The Commission therefore concludes that it is appropriate to reflect the decrease in the Companies' avoided energy costs and allow the ratepayers that pay for these costs to appropriately benefit from that decrease in the avoided energy costs that they ultimately bear.

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[17] *See* Duke Energy Carolinas and Progress Energy Carolinas Joint Reply Comments, filed March 28, 2013 in Docket No. E-100, Sub 136, at p. 10 and Confidential Exhibit A.
[18] Companies' Reply Comments at 5, fn. 8, citing actual historic market data based on United States Energy Information Administration, Henry Hub natural gas prices, current as of August 6, 2015.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Hedging is a method of purchasing a commodity in the future at a price determined in the present. In some instances, it is used as a mechanism to help moderate increases in the price of fuel but, more often, to reduce price volatility. In its Phase One Order, the Commission determined it appropriate to recognize hedging costs that the utility avoids as a result of energy purchases from QF generation. The Commission's decision was based on its belief there are fuel hedging benefits associated with solar generation and other renewable generation because purchases from QFs reduce the amount of fuel that needs to be purchased. In implementing the Commission's directive, the Companies utilize a 10-year liquid market approach, which uses actual, quoted transaction costs rather than forecasted information. The Companies indicated that they had obtained both "bid" and "ask" prices from different suppliers of natural gas over a 10-year period. This longer time horizon permits them to use actual quotes from suppliers and eliminates the need for use of forecasted data except for the period beyond the 10-year horizon for which actual quotes were available. The "bid" price is the price at which the third party is willing to "buy," and the "ask" price is the price at which the third party is willing to sell. The Companies noted that for planning purposes in other dockets, they have sometimes used the mid-range between the "bid" and "ask" price as a reasonable proxy for future gas markets. However, for the purposes of this docket, the Companies noted that, while they seek to negotiate the most favorable price possible, they sometimes might have to pay the full "ask" price to complete the transaction. Thus, to reduce the possibility that they might underestimate the hedge price, the Companies' assumed that they would pay the full "ask" price rather than the mid-point. In the

Companies' view, this approach actually benefits the QF because the "ask" price will always be higher than either the "bid" price or the mid-point.

In its Initial Comments and Reply Comments, the Public Staff argued that the Utilities have not properly reflected the hedging value of QF generation in their avoided energy cost calculations. The Public Staff recommended that the Commission direct the Utilities to recalculate the avoided energy component using a hedge value of at least 0.09 centers per kWh in each year of the PPA term. The Public Staff also proffered the Black-Scholes Option Pricing Model as a viable method to determine hedging value for natural gas. Under this method, the Public Staff would adopt a future quote and convert it to a spot price for gas.

NCSEA criticized the approaches used by both the Companies and DNCP. In its Initial Comments, NCSEA argued that DNCP failed to capture the full level of risk that can be avoided by customers over the appropriate time horizon by only capturing the portion of that risk against which the utility is actually hedging. In criticizing the Companies, NCSEA stated that the hedging allowance must be provided in each year of the contract term to reflect the fuel hedging benefit year to year. In its responsive comments, NCSEA reiterated its criticism of the utilities calculation of the utilities' hedging costs, and agreed 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. Although the NCSEA shared the Public Staff's concern that the Utilities have not properly reflected the hedging value of QF generation in their avoided energy cost calculations, the NCSEA took issue with the "risk free interest rate" used by the Public Staff in calculating the hedge value in its Black Scholes method. NCSEA proposed using an interest rate of at least 3.10%, instead of the 1% used by the Public Staff. NCSEA recommended the Utilities 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. Additionally, NCSEA requested that the Commission indicate a willingness to revisit this issue in a future proceeding, particularly if a national consensus on methodology emerges.

In its Initial Comments, SACE stated that gas commodity price forecasts do not have a "bid" and "ask' price, just a clearing price. SACE argued that fuel hedging involves purchasing natural gas futures, not purchasing natural gas at forecasted prices. Therefore, Utilities should use natural gas future prices, not commodity prices, when calculating the fuel hedging benefits associated with purchases of renewable energy from QFs. In its responsive comments, SACE reiterated its initial criticisms of the fuel hedging calculations and also expressed support for use of a Black Scholes Option Pricing Model to calculate the hedge value of renewable energy purchases.

Contrary to assertions by NCSEA, SACE and the Public Staff, the Companies contended that they do not use forecasted or hypothetical numbers. Rather, the Companies' numbers are based on actual price quotes. The Companies stated that the quotes are current prices obtained from existing suppliers and not future prices as the Public Staff suggests.

Conclusion

The Commission is aware of the difficulties inherent in making hedging cost calculations and the different approaches that might be used. Clearly, none of the approaches is simple, and none of the approaches is perfect. The Commission notes that the process adopted by the Companies provides the equivalent of a no cost reverse hedging benefit to the QFs. If the price of gas declines, the QF is protected because the QF will continue to enjoy the benefits of the higher gas prices for the term of the existing contract. Even if gas prices drop to a level that the Companies and their retail customers would be economically benefited by self-generation, the Companies continue to purchase from the QF at the higher price. If the price of gas should increase, the QF has the option of increasing its capacity size to negotiate a separate contract based on the higher price of gas. In many instances, the QF chooses to build facilities only slightly below the threshold that would disqualify it from taking advantage of the standard tariffs, so the capital costs associated with such a modification should not be impossible to accomplish. QFs enjoy these potential benefits at no cost to them.

As previously acknowledged, establishing a hedge value is a difficult exercise, and there is no single method that is perfect. In the final analysis, the test must be whether the avoided cost process produces a reasonable result, which incorporates the hedging savings produced by renewable generation. In this instance, the Commission concludes that the use of 10-year actual quotes obtained from suppliers is a reasonable approach and produces a reasonable result. The conclusion is supported by the fact that the Companies used the actual "ask" prices rather than "bid" price or mid-range, which produces a higher avoided cost for the QF. The QFs also receive the benefit of reverse hedging without any additional costs to them. At some point, the process must be brought to a close particularly when the process already utilized produces a reasonable result. For the purposes of this docket, the Commission concludes that it is more appropriate to use the actual "ask" price obtained from suppliers that to utilize the Black

Scholes Method, which requires using more speculative input data in the model.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The peaker methodology used in determining avoided capacity costs focuses on the costs of constructing what is generally called a hypothetical CT. Therefore, in its Phase One Order, the Commission ordered the utilities to use publicly available industry sources, and to tailor that information only to the extent clearly needed to adapt such information to the Carolinas and Virginia. With respect to economies of scale and economies of scope, the Commission ordered the utilities to use economies of scale in their avoided cost calculations but not economies of scope. Economies of scale relate to building multiple CTs at a single site while economies of scope relate to building multiple CTs at the same time. The reality of actual CT construction allows for the use of economies of scale but not economies of scope.

The Public Staff noted in its Reply Comments that the EPRI data relied upon by the Companies was subscription based and not as publicly available as EIA or PJM data. The Public Staff argued the utilities should strive to utilize data from publicly available sources and provide clear justifications for any adjustments made to publicly available data. The Public Staff did not address economies of scale and scope with respect to DEC and DEP in its Initial Comments. However, in its Reply Comments, the Public Staff agreed with NCSEA and SACE that economies of scope were not properly excluded. With regard to DEC and DEP, however, the Public Staff took no exception to their installed costs of a CT.

In its Initial Comments, NCSEA stated that while the EPRI data is arguably an industry source, it is not for general public distribution and is available to EPRI members only at a significant cost. NCSEA further argued that the data relied upon by the Companies in their March 2015 filing was marked confidential, which contradicts the notion that the data is publicly available. NCSEA alleged the EPRI data does not provide the complete cost of a CT, and therefore, DEP and DEC contracted with Burns and McDowell, an engineering firm, to complete their cost calculations, and that this data was not publicly available. NCSEA argued DEC/DEP "cherry picked" data violating the Commission directive of tailoring only when clearly needed. In its Reply Comments NCSEA emphasizes, in spite of the Public Staff's failure to do so, the Commission should carefully review the utilities' compliance with the requirement that the data be modified only when clearly needed.

Further, in its Initial Comments, NCSEA argued that the Companies were not transparent and did not comply with FERC rules in providing documents for public inspection, under FERC Order No. 69, and §292.302(b). NCSEA argued that the Companies' use of EPRI data marked "confidential" violated this FERC requirement.

With respect to economies of scope and scale, NCSEA argued that the EPRI data did not distinguish between economies of scope and scale. NCSEA acknowledged that DEC and DEP persuasively argued they used a 2x2 unit site rather than a 1x4 unit site to make the number roughly equivalent to only using economies of scale. NCSEA further argued that DEC and DEP were not required by the Commission to use any economies of scale. NCSEA suggested DEC and DEP could have started with a 1-unit site and adjusted cost estimates downward to better exclude economies of scope.

SACE complained that DEC and DEP did not disclose the data in its March 2015 filing, marking that data as confidential. Interested parties had to resort to data requests to obtain the data, some of which was marked confidential when provided. SACE argued the Companies failed to comply with the Commission directive to use publicly available data. SACE agreed with the NCSEA on economies of scale and scope, but further stated that if DEC and DEP cannot completely exclude economies of scope from their data, they should not include any economies of scale.

DEC and DEP submitted in their Reply Comments that just because the EPRI data is not free of cost does not mean the data is not public. The Companies argued that the Commission's intention in its Phase One Order was to provide all parties with a robust set of baseline industry data that could be utilized to produce the best possible result. They continue to believe the best data is their actual CT costs. According to the Companies, there is an inherent conflict in using publicly available data and using data that requires few adjustments. The more public data is, the more generalized it tends to be and greater adjustments will be needed to achieve an accurate result. The Companies pointed out that NCSEA criticized DNCP for using PJM and EIA due to the adjustments required to make that more generalized data applicable to DNCP. Finally, the Companies noteed all of the data provided by EPRI was provided to the other parties. The Companies are allowed to share that information with the other parties so long as EPRI's copyrights are respected.

DEC and DEP argued that SACE's position on economies of scale and scope is extreme and that judgment is necessary in developing avoided cost rates. Under PURPA, DEC and DEP are required to design rates that make customers indifferent to whether energy is produced by the QF or the utility. The Companies argued that, because this Commission recognized economies of scale as appropriate, the Companies are required to include them so not to violate the indifference standard of PURPA. The Companies acknowledged that the NCSEA's preferred method of starting with a 1-unit CT could be done; however, DEC and DEP made a different judgment. The Companies suggested that the question before the Commission is not what equation was used, but whether the result complies with the PURPA standard of providing an avoided cost payment that makes customers indifferent as to whether the capacity is provided by a CT or a QF.

<u>Conclusions</u>

While the Commission acknowledges that EPRI data is not publicly available in the sense of being free to access, the purpose of the Commission's directive to use publicly available data was to provide a baseline set of data for all parties outside the utilities' own costs. The purpose was to make industry data available to all parties rather than insisting the data be obtained at no cost. In this sense, the EPRI data fits the definition of "publicly available." The data was provided to each party in this docket at their request. The fact that the data was obtained by data request and marked confidential is not determinative of whether the data fit the definition of "publicly available" in this Docket. That is simply part of the ordinary process involved in Commission proceedings of this type. The data provided was more specific than that provided by EIA and PJM, and required fewer adjustments, also a Commission directive. It would have been unwise for the Commission to insist that only free data be used because the likelihood is that such data would be very generalized and less robust than the data available through EPRI.

In regards to FERC Order 69 and §292.302, those provisions provide for the public inspection of avoided cost energy rates and the electric utility's plan for additional capacity through purchases of firm energy and generation. They do not require the disclosure of proprietary information or information that might be useful but subject to copyright protections. The information referenced under the above provisions is available to the public through the filing of avoided costs rates, and other filings, including Integrated Resource Plans. This information allows a potential investor in a QF to estimate with reasonable certainty the return on a potential investment before the construction of a facility and therefore complies with FERC rules under PURPA.

The Commission recognizes that determining capacity costs is not a completely scientific and quantitative exercise. Some judgment is inherently involved in the process. The Commission determined that economies of scale should be reflected in avoided capacity cost but economies of scope should not. However, it may be impossible to isolate the two to an absolute certainty using publicly available data or any other source of data. This does not mean that economies of scale must be totally excluded from avoided cost rates. Excluding economies of scale would violate the "indifference standard" of PURPA to the detriment of ratepayers and deprive ratepayers of the economic benefits of economies of scale. Clearly, DEC and DEP could have used many formulas to develop their avoided capacity costs, but the Commission does not believe that it should dictate that utilities use a specific formula for determining capacity costs in all instances. The Commission must only determine if the formula chosen by the utility arrived at a reasonable result, and in this case, the Commission concludes that it did.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 5 AND 6

In the Initial Comments, NCSEA was the only party that asserted that DEC and

DEP had used a contingency adder that was too low and had estimated useful lives that were too high in calculating the installed cost of a CT. According to NCSEA, DEC and DEP proposed the same contingency adder in the 2012 biennial proceeding that they propose now – [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. NCSEA, however, criticized the Companies' contingency adder as inconsistent with Commission's previous orders because, according to NCSEA, it does not reflect the early stages of planning for the construction of a hypothetical CT. To support its contention, NCSEA replied upon EPRI TAG data that provided a [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] contingency adder, as well as the Brattle Report[19] and a report from Black & Veatch[20] that describe how a contingency adder is needed to account for various unknown costs that are expected to arise due to a lack of complete project definition, permitting complications, greater than expected startup duration, etc.[21] NCSEA also cited Public Staff testimony from an earlier avoided cost proceeding, arguing that the Companies' proposed adder is "more appropriate" for a project fairly far down the road in terms of development.

NCSEA further argued that in Phase One of this proceeding, the Commission did not "specifically" accept the contingency adder that the Companies have proposed here, but instead directed the Companies to include a contingency adder that was consistent with a hypothetical plant in the early stages of planning. NCSEA concluded that a contingency adder less than [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

[19] Cost of New Energy Estimates for Combustion Turbine and Combined Cycle Plants in PJM, prepared for PJM Interconnection, LLC by The Brattle Group and Sargent & Lundy, dated May 15, 2014 (the "Brattle Report").
[20] Cost Report: Cost and Performance Data for Power Generation Technologies, prepared by Black & Veatch for National Renewable Energy Laboratory, February 2012.
[21] NCSEA Initial Comments at 30.

is not adequate, even for internal purposes, during the early stages of the planning period.[22] To that end, NCSEA proposed a contingency adder of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

With respect to the useful lives proposed by DEC and DEP, NCSEA noted that the assumed useful life of a CT influences the avoided capacity costs because the longer the assumed useful life, the lower the carrying cost, and therefore, the avoided capacity cost. In support of its claim that the useful life assumption should be shorter, NCSEA again cited the EPRI TAG data that included a useful life of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] years, and noted that prior to the 2012 biennial avoided cost proceeding, both DEC and DEP had assumed shorter useful lives. NCSEA also cited a data request response from DEC in the previous avoided cost docket, the Sub 136 proceeding, that indicated that its past useful life assumptions were reasonable and conservative, based on internal studies and assumptions by external industry groups. In addition, the response cited by NCSEA noted that DEC's "past depreciation studies had assumed a [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] year or greater useful life for a CT."[23]

In its Reply Comments, the Public Staff did not discuss the Companies' useful life assumptions. It stated that it did not raise an issue with the Companies' contingency adder, because " the overall installed cost of the CT used for the purposes of calculating avoided capacity rates seemed reasonable and the nominal increase in the projected CT cost from the 2012 proceeding was comparable to the price trends compiled by the

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[22] NCSEA Initial Comments at 31.
[23] NCSEA Initial Comments at 36.

Bureau of Labor Statistics.'[24] In contrast, the Public Staff contested DNCP's proposed contingency adder, in part because it used a new model CT "with which it has no construction or operational experience."[25]

In its Reply Comments, NCSEA repeated assertions from its Initial Comments, recommending that, even though the Companies' contingency adder was apparently "overlooked" by the Public Staff, the Commission should direct DEC and DEP to multiply its proposed contingency adder by at least three, and as high as four, times when calculating its installed cost of a CT.[26] Moreover, NCSEA recommended that the Commission direct the Companies to use the useful life set forth in the EPRI TAG data upon which it relied in calculating the installed cost of a CT.

In the Companies' Reply Comments, they noted that they used their more than forty years of experience in constructing and operating CTs in the Carolinas to develop a contingency adder and their useful life assumptions. With respect to the contingency adder, they referred to their filings in both the Sub 136 proceeding and in Phase One of this proceeding where they had demonstrated that six of the Companies' most recent CT *and* Combined Cycle ('CC") projects (which include CT technology) have used little to no contingency, with only two of the six projects requiring a portion of the small contingency adders that the Companies had included. NCSEA's proposed increased contingency adder of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] more than *triples* the contingency adders that the Companies have experienced in their operations in the Carolinas. Therefore, the Companies contended that NCSEA's proposed contingency adder was overly high and utterly unrelated to DEC's and DEP's

[24] Public Staff Reply Comments at 7.
[25] Public Staff Reply Comments at 7.
[26] NCSEA Reply Comments at 15.

experiences.

The Companies further noted that the Commission has not rejected DEC's and DEP's [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] contingency adder, which the Companies have used in their IRPs since 2013 and in the past two avoided cost proceedings (the Sub 136 proceeding and Phase One of this proceeding). The Companies recounted that, in the Sub 136 proceeding, the Public Staff and the Companies settled on an installed CT cost per kW for purposes of calculating the Companies avoided capacity rates in this proceeding; thus, the Commission did not directly approve or disapprove the contingency adder proposed by DEC and DEP.

With respect to their useful life assumption, the Companies estimated a [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] year useful life for a CT in calculating their avoided capacity costs. They noted that no party challenged evidence produced in Phase One that showed that the vast majority of CTs on the Companies' systems have operated or are expected to operate for [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] years or more.[27] Thus, the Companies' experiences could actually support a longer useful CT life than [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] years.[28]

The Companies further cited witness Snider's testimony from Phase One, where he referred to the useful life assumptions in each of the Companies' independently completed updated depreciation studies supporting their proposed depreciation rates.[29] DEP's most recent depreciation study uses a [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] year useful life for its CTs. DEC's most recent depreciation study

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[27] Tr. Vol. 1 at 192
[28] Id.
[29] Tr. Vol. 1 at 190-93.

considered a lifespan of a new CT to be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] years.[30]

<u>Conclusion</u>

Based upon the foregoing, the Commission concludes that the Companies' contingency adder and useful life assumptions are reasonable and appropriate. AACE International defines "contingency" as:

> an amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and *that experience shows will likely result, in aggregate, in additional costs*. Typically estimated using statistical analysis or *judgment based on past asset or project experience*, contingency usually excludes: 1) major scope changes such as changes in end product specification, capacities, building sizes, and location of the asset or project; 2) extraordinary events such as major strikes and natural disasters; 3) management reserves; and 4) escalation and currency effects.

Cost Engineering Terminology, AACE International Recommended Practice No. 10S-90, April 25, 2013 at 21 (emphasis added). The equipment for constructing a CT is generally uncomplicated and standardized; the construction process for a CT is relatively quick and straightforward. Because of their uncomplicated nature, CT projects are not prone to the unforeseen risks and circumstances that a contingency adder is intended to cover. Consistent with these facts, and with their experience in constructing the operating CTs, the Companies demonstrated in Phase One and the Sub 136 proceeding their six most recent CT *and* CC projects (which include CT technology) used little to no contingency. No party has effectively contested the Companies' experience in constructing CTs in the Carolinas.

[30] Id.

The Commission disagrees with NCSEA's recommendation to triple or quadruple the contingency adder proposed by the Companies. Contrary to NCSEA's assertions, the Companies' proposed contingency adder does not violate any prior Commission decisions. Due to the settlement in the Sub 136 proceeding between the Companies and the Public Staff, witness Hinton's pre-filed testimony, which NCSEA cites in this case, was entered into the record but was not subject to cross-examination by the Companies. Consequently, the Commission did not cite or credit this testimony in the Commission's Order in the Sub 136 proceeding. Moreover, the Commission did not reject the Companies' contingency adder, which they have included in their avoided cost filings since 2012 and in Phase One of this proceeding.

Second, the Commission agrees with the Companies that their actual operational experiences in the Carolinas are the best and most appropriate methods to determine the appropriate contingency adder, instead of more generic studies that do not directly relate to the Carolinas. The Brattle Report, cited by NCSEA in support of its arguments against the Companies' contingency adders, does not apply to DEC and DEP's service area in the Carolinas. The Black & Veatch Report assumes, among other things, "on-site construction in the Midwestern United States."[31] Employing NCSEA's suggestion that the contingency adder should be higher only results in an avoided capacity cost rate that is in excess of DEC's and DEP's actual avoided contingency costs and produces an unreasonable result.

In addition, with respect to the useful lives proposed by the Companies, NCSEA presents no compelling reasons why DEC and DEP should depart from their operational experiences and their depreciation studies, which were utilized in the most recent rate

[31] NCSEA's Comments, Exh. 3 at 3.

cases before the NCUC, and instead utilize a proposed shorter useful life, resulting in higher avoided capacity rates. NCSEA argues that that the EPRI TAG data assumes a useful life of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] years, and that prior to the 2012, DEC had used a [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] year life and that DEP had used a [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] year useful life. From there, NCSEA recommends that the NCUC direct the Companies to decrease their useful life estimation to that used in the EPRI TAG data, without reference to the Companies' forty plus years of experience in the Carolinas.

The Companies' estimates of the useful life of a CT, however, are reasonable and appropriate. Avoided capacity rates should reflect the capital costs that the purchasing utility actually avoids if it purchases power from a QF rather than generating the power itself. The rates paid by customers for QF power should not exceed the purchasing utility's avoided cost. Thus, it follows that the best reference points to use in determining the useful life of a CT in setting avoided cost rates are: (1) the actual operating lives of the utility's CT fleet and (2) the CT useful life assumptions used in setting the utility's base rates. No party has presented evidence contesting the Companies' system operation. In addition, the Companies' most recent depreciation studies use a [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL year useful life for DEP and a [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] useful life for DEC. The costs that North Carolina customers bear for a CT in a rate case and the reasonable expectation of how long a CT should operate in the Carolinas are appropriate to consider in estimating the useful life for the calculation of the avoided capacity rates in this docket. By those measures, the Companies have justified their reasonable estimation of the useful life. Accordingly, the Commission approves the Companies' contingency adder and useful life estimates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

In their Initial Statements, DEC and DEP stated that they had revised certain of their avoided cost calculations to incorporate best practices and to adopt a more unified approach to calculating avoided cost rates for DEC and DEP. Among these stated revisions are the seasonal allocations factors.[32] The Companies' respective March 2 filings reflect the proposed seasonal allocations, based on historical CT production, of 80% on-peak months / 20% off-peak months for DEC Option A, 60% summer months / 40% non-summer months for DEC Option B, and 60% summer months / 40% non-summer months for DEP Options A and B.

In response to data requests by the Public Staff, DEC and DEP provided data supporting their proposed seasonal allocations. Consequently, in its Initial Comments, the Public Staff stated that the provided data "supported the 60%/40% weighting for summer and non-summer months for the proposed avoided capacity rates under DEC Option B and DEP Options A and B, and the 80%/20% (summer/non-summer) weighting for DEC Option A."[33] The Public Staff further stated that it did not take issue with the weightings or methodologies used by the Companies to weight avoided capacity costs in this proceeding. The Public Staff concluded by noting that further review may be needed in the next avoided cost proceeding to determine if the seasonal allocation factors proposed in this proceeding remain reasonable.

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[32] The seasonal allocation factors are shown on pages 6-9, 17-20, 23-26 and 29-32 of each Company's confidential Exhibit 6 from their March 2, 2015 filings.
[33] Public Staff Initial Comments at 43.

In its Initial Comments, NCSEA contended that "DEC and DEP have modified inappropriately the weighting given to summer and non-summer months in calculating their rates in this proceeding."[34] NCSEA noted that in the Sub 136 proceeding, the Commission directed DEP and DNCP to include an Option B using the same on-peak hours as used at the time by DEC. In addition NCSEA referenced the 2012 Stipulation of Settlement between DEC, DEP and the Public Staff regarding modification of Option B on-peak hours. NCSEA acknowledged that the seasonal weighting was not specifically presented in the proceeding, but nonetheless contended that it is closely related to the issues presented relating to the modification of Option B and recommended consideration of this change be deferred until a future hearing.

In their Reply Comments, DEC and DEP reiterated their objective of standardizing best practices and methodologies to achieve administrative efficiencies and reducing the chance for confusion and mixed messaging. In addition, the Companies stated that the continuation of differing legacy seasonal allocation approaches for similar seasonal definitions results in an unjustifiable difference in price signals between the two operating companies for QFs doing business in North Carolina. The Companies illustrated through a table the difference in the currently approved seasonal weightings resulting from differing legacy allocation approaches; the proposed weightings based on individual supporting data analyses; and the resulting change in allocation percentage for each option listed. The table showed that the proposed allocation values for DEC's Option B are simultaneously a decrease to the summer weighting by 19% and an increase of the same percentage to the non-summer weighting. Conversely DEP's Option A and Option B showed an increase of 22% and 17% to the summer weighting, respectively,

[34] NCSEA Initial Comments at 36.

and a simultaneous decrease of the same percentages to the respective non-summer weightings.

DEC's Option A was not reflected on the table because it does not share the same summer month definition of June-September as the three options included. In addition, the table does not show the on-peak hours associated with any of the options because they did not change as a result of the change in seasonal allocation factors.

The Companies also noted in their Reply Comments that NCSEA appears to accuse them of violating the Stipulation of Settlement with the Public Staff in the Sub 136 proceeding. The Companies further noted that the Public Staff's comments did not mention the settlement agreement but did credit the data supporting the Companies' proposal in its Initial Comments.

Conclusion

The Commission concludes that the Companies' seasonal weighting is appropriate. First, consistent with the Phase One Order, DEC and DEP continue to use the same Option B on-peak hours (for both summer months and non-summer months) as agreed to in the Settlement Agreements entered into among DEC, DEP, DNCP and the Public Staff in the Sub 136 proceeding. Next, the Commission finds that NCSEA's argument that the change in the seasonal allocations results in a decrease to all summer weightings is incorrect. The table provided in the Companies' Reply Comments demonstrates that this is not the case.

In addition, the Commission disagrees with NCSEA's claim that the proposed seasonal method is inconsistent with the peaker method and should be rejected. In the peaker method, the capacity price is determined based on the annualized cost of a peaker plant. The application of the seasonal allocation factor does not change the annualized cost of the hypothetical CT and is therefore not inconsistent with the peaker method. The annualized cost of a peaker has historically been allocated to on-peak and off-peak seasons in both Companies' legacy capacity rate calculations. The use of long-term CT data analysis as the basis of this allocation is a reasonable method for developing a consistent approach between DEC and DEP.

Based on the foregoing, the Commission concludes that the Companies' seasonal weighting methodology, based on historical CT production, is considered a reasonable approach and should be utilized by DEC and DEP in their respective avoided cost calculations.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 8

DEC's Schedule PP-N and PP-H included a provision that stated that, "This Schedule is not applicable to a qualifying facility owned by a Customer, or affiliate or partner of a Customer, who sells power to the Company from another facility within one-half mile." In the Companies' avoided cost filings, they included this provision in both DEC's and DEP's proposed Schedule PP.

In its Initial Comments, SACE argued that this language exceeded FERC's recent orders. SACE cited a FERC order that indicated that, when determining whether two generators near each other should be viewed as a single facility or two separate facilities, for purposes of a capacity threshold under PURPA, there are three criteria that should be considered: distance between facilities (measured between the respective facilities' electric generating equipment), ownership, and the type of energy resource. The requirement that two facilities be located more than one mile apart only applies to facilities under common ownership that use the same type of energy resource, according to SACE. SACE concluded by arguing that the one-mile radius restriction should only apply when two proposed facilities under common ownership use the same energy resource. SACE also added that the distance between facilities is measured from the electrical generating equipment of a facility for purposes of making the one-mile determination.

NCSEA did not oppose DEC's and DEP's provision in its Initial Comments.

The Public Staff did not raise this issue in its Initial Comments, but in its Reply Comments, stated that DEC had historically included a similar one-half mile availability limitation. The Public Staff also agreed with SACE's recommendations that the one-half mile restriction should only apply to facilities that use the same energy resource and that the Utilities should include language stating that the distance between the facilities should be measured from the electrical generating equipment of the facility. The Public Staff recommended the availability limitations for each utility be limited to one-half mile, while maintaining the qualification that two or more QFs under the same or affiliated ownership are eligible for standard offer rates and terms so long as the combined capacity of those facilities does not exceed 5 MW.

In their Reply Comments, the Companies distinguished the applicability of the case cited by SACE, which pertained to the FERC requirements for certification of a facility as a QF under the "one-mile" rule from the availability of the standard offer, which is determined by the Commission. DEC and DEP noted that their respective Schedule PPs are consistent with the FERC one mile rule because each provide that the Schedule is available to facilities that are certified as QFs as defined by the FERC's regulations at 18 C.F.R. §§ 292.203, 292.204, and 292.205. The Companies then compared the provision with the Commission's prior decisions to maintain a 5 MW threshold for availability, noting that the provision works with the threshold because it limits larger QFs that are owned by the same seller, or an affiliate or partner of that seller, from breaking themselves up into smaller, closely-located 5 MW or less facilities. The Companies further reported that this contested provision had been included in DEC tariffs since 1997 and that no party appeared to have challenged it until now.

Based upon the foregoing, the Commission approves the inclusion of the Companies' proposed one-half mile provision in Schedule PP. This provision has been included in DEC's Schedule PP-A and PP-H since 1997 and the Commission believes that as DEC and DEP work to incorporate best practices, it is reasonable and appropriate to include this provision in DEP's Schedule PP, too. The Commission adopted its 5 MW eligibility threshold for standard offers in Docket No. E-100, Sub 41A to ensure that developers of smaller projects that do not have the resources or expertise to negotiate a contract with a utility could avail themselves of the utilities' standard offer. Thus, the intent of the provision included in DEC's former Schedule PP-N and PP-H was to ensure that larger developers of QFs do not thwart the Commission's intent by breaking up their facilities in geographically adjacent facilities of 5 MW or less in order to avail themselves of the standard offer. In other words, the Commission did not intend for larger facilities to evade negotiating with a utility by breaking into smaller, closely located facilities of 5 MW or less.

Moreover, the Commission concurs with the Companies that this provision is not contrary to FERC precedent or regulations. In 18 C.F.R. § 292.204, the FERC established the criteria for qualifying as a small power production facility as follows:

> [t]he power production capacity of a facility for which qualification is sought, together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 MW.

In addition, "facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought."[35] This "one-mile" rule applies to the qualifications to become as QF in the first place and not to the applicability of the standard terms and conditions. Both DEC's and DEP's Schedule PP are consistent with the "one-mile" rule.

The availability of the standard offer, however, is a Commission determination, not a FERC one. In the Phase One Order, the Commission reaffirmed the 5 MW eligibility thresholds for the standard offer. Accordingly, the Commission concludes that the Companies' provision providing that their Schedules are not applicable to a QF owned by a customer, or affiliate or partner of a customer, who sells power to the Company from another facility within one-half mile is consistent with the intent of the 5 MW thresholds. No party has offered a compelling legal or policy reason to alter or add to this provision that the Commission has essentially approved since 1997. Therefore, the Commission approves inclusion of this provision in the Companies' Schedules.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The Companies included the following provision in their Terms and Conditions:

> If Seller's average energy generated on-peak or off-peak periods or capacity during any 12 month period falls significantly below the Contract annual kilo-watt hours or Contract Capacity, the Company may petition the North Carolina Utilities Commission to invoke a Reduction in Contract Energy Charge or Reduction in Contract Capacity Charge and

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[35] 18 C.F.R. § 292.204(b).

establish a new Contract Energy or Capacity level.

NCSEA opposed inclusion of this provision in its Initial Comments. In support, NCSEA discussed the Sub 136 proceeding where DEC had proposed to incorporate a similar provision from DEP's standard contract. In that case, the Commission had struck the proposed provision but had invited DEP to propose an alternative provision. NCSEA argued that the alternative provision proposed in this proceeding should also be struck because it is inconsistent with DEP's stated purpose of ensuring QFs do not decrease production in the later years of levelized QF contracts. NCSEA also criticized the provision as unnecessary and unduly punitive for QFs that generate electricity using variable resources and will inevitably present a barrier to the QF's ability to obtain financing.

Furthermore, NCSEA characterized the proposal as confusing because it combines shortfalls of capacity and energy into a single triggering condition, and it does not define "significantly below." NCSEA indicated that DEC had explained in response to a data request that "significantly below" means a permanent reduction (six consecutive months or more) a twenty percent or more reduction in annual energy production or generator capacity and that contract energy is intended to represent the estimated annual energy production expressed in kilowatt hours that the seller anticipates supplying to the Company annually, as specified by the QF in the PPA. NCSEA concluded that the Companies have not established that the provision bears any relationship to the harm it is intended to prevent – underproduction in later years of a contract resulting in overpayment during the early years of a levelized contract.

The Public Staff did not raise this issue in its Initial Comments. In its Reply

Comments, the Public Staff stated that NCSEA had taken issue with the proposed Reduction in Contract Energy and Reduction in Contract Capacity charge in DEC's and DEP's terms and conditions, which would allow for the Companies to apply to the Commission on a case-by-case basis for approval to impose a charge in the event the QF's average energy generated or capacity falls significantly below the contract energy and capacity levels. The Public Staff cited its previous comments in the Sub 136 proceeding that stated that the Commission had previously held in Docket No. E-100, Sub 59, that a utility could require a QF to state the amount of capacity and energy it intends to provide, but the utility could not use the stated amount to penalize the QF, particularly a QF that cannot control its fuel. The Public Staff stated the QFs, under standard contracts are not paid unless they are generating, and, therefore, a penalty is unwarranted. The Public Staff acknowledged that there was some risk that a QF could underperform in the later years of a long-term levelized contract after receiving the benefits of a levelized contract in the early years, but, in the Public Staff's opinion, the Companies' provision did not address this concern. Therefore, the Public Staff recommended that this provision be struck from DEP's and DEC's terms and conditions and, in the interim, the Companies could apply to the Commission for approval to impose a charge on a case-by-case basis, at which time the Commission could determine the extent, if any, of any harm.

In their Reply Comments, the Companies agreed that, in the Sub 136 proceeding, they had included a Reduction in Contract Energy Charge and that the Commission had directed that it be struck. The Companies explained that their rationale for inclusion of such a provision was to protect their customers. According to the Companies, long-term levelized rate QF contracts create a tension between encouraging QF development, on one hand, and the risk of overpayment to QFs on the other. Long-term levelized rates tend to overpay the QF in the early years and underpay the QF in later years. Therefore, the Companies were concerned that a QF's economic incentive to incur the costs of operating and maintaining the facility diminishes and could even disappear over the life of a long-term contract. The Reduction in Contract Energy charge addresses that situation by providing a mechanism to adjust the contract to restore the expected balance of the economic benefits to both parties if the QF's performance falls materially short of its contractual obligation. The Companies acknowledged that the Commission had directed them to remove this provision because it was inconsistent with previous Commission rulings and with the purpose of ensuring QFs do not decrease production in the later years of levelized QF contracts, but indicated that they had complied with the Commission's invitation to propose a provision that allowed it to take action of the QF has lower production in the later years of a long-term contract.

The Companies also reported that the recent inspections of solar facilities by Advanced Energy had heightened their concerns about the possibility of QF facilities underperforming in later years. The Companies highlighted several findings from the report of those inspections, including that some solar sites with substantial shading from vegetation and portions of the arrays out of service or facing north. The Companies expressed concerns that, allowed to continue, these circumstances will lead to the situation that the proposed provision is intended to remedy. The Companies thus concluded that the troubling lack of oversight and maintenance issues signaled that the Companies' provisions were appropriate and necessary to encourage performance by the

QF, so that ratepayers have not overpaid in early years for underproduction in later ones.

The Companies also distinguished their proposed provision from the one the Company struck in the Sub 136 proceeding. The Companies contended that this new proposal was not intended to be punitive as the Companies will not impose a charge without Commission approval. To obtain Commission approval, they will need to make a showing that such a charge is justified.

Conclusions

Based on its review of the comments on this issue, the Commission is persuaded that the Companies' Reduction in Contract Energy and Contract Capacity charge is reasonable and appropriate. The provision will incent QFs to maintain performance, thereby protecting ratepayers.The Commission is not persuaded by the arguments of NCSEA and the Public Staff that this provision should be rejected because it is too similar to the one the Commission rejected in Sub 136 proceeding and that it is not designed to address the problem of a decrease in production in later years of a contract. First, the provision rejected in Sub 136 proceeding provided the following:

> After the first two years of operation of the Facility, if Seller's average energy generated in the on-peak or off-peak periods during any 12-month period falls below 80% of the Contract On-Peak or Off-Peak level, the Company may invoke a Reduction-in-Contract Energy Charge and establish a new Contract Energy level of on-peak and off-peak energy periods, respectively.

In contrast, the provision proposed by the Companies may not unilaterally impose a charge if average production falls below 80%. Instead, the Companies must seek and obtain Commission approval before imposing any charge and must make a satisfactory showing that such approval is warranted. This is appropriate because the Commission should be able to determine if the ratepayers are being harmed. If the Commission determines that the charge is not warranted, that is, if the Commission does not find that production has not fallen sufficiently or it is too early in the contract term to impose a charge, the Commission may so find.

The Public Staff has recommended that the Companies propose a new alternative that is more closely aligned to preventing QFs from obtaining benefits in the early years of a contract and then underperforming in later years. The Public Staff suggested that, in the interim, the Companies apply to the Commission to impose a charge on a case-by-case basis, at which time the Commission may determine the extent of the harm. The Public Staff's recommendation, however, is exactly what the Companies are proposing with their provision – the ability to petition the Commission for relief for ratepayers on a case-by-case basis. Allowing relief on a case-by-case basis, while excluding the express provision from the terms and conditions, however, deprives the QFs of notice of the possibility that the Companies may seek relief. Moreover, the value of this provision is that it will act to encourage QFs to maintain oversight and operation over their facilities, so that the issues identified by the Advance Energy inspections do not remain or worsen, harming ratepayers. For these reasons, the Commission approves inclusion of the Companies' Reduction in Contract Energy and Capacity Charge provisions in their Terms and Conditions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The Companies included the following provision in their Terms and Conditions:

> Assignment of Agreement - A Purchase Agreement between Company and Seller may be transferred and assigned by Seller to any person, firm, or corporation purchasing or leasing and intending to continue the operation of the plant or business which is interconnected under such

> Agreement, subject to the written approval of Company. Company will grant such approval upon being reasonably satisfied that the assignee will fulfill the terms of the Agreement and if, at the Company's option, a satisfactory guarantee for the payment of any applicable bills is furnished by assignee. However, before such rights and obligations are assigned, the assignee must first obtain necessary approval from all regulatory bodies including, but not limited to, the Commission.

In its Initial Comments, NCSEA objected to this provision, indicating that it gave the Companies "undue discretion" to disapprove or put onerous conditions on the assignment rights, such as the requirement of financial security, which has the potential to impede QF development. NCSEA recommended that the Commission direct the Companies to revise the provision to require that they not unreasonably withhold consent on a proposed assignment and not require commercially unreasonable measures, such as security.

In its Reply Comments, the Public Staff noted that the Commission has included standard rates, terms and conditions in its biennial avoided cost proceeding since Docket No. E-100, Sub 41A to reduce transaction costs for smaller project developers who may not have the resources or expertise to negotiate with the utility. Thus, the Public Staff agreed with NCSEA's assertion that the Companies' proposed assignment provisions could constitute an unreasonable burden on QF development and recommended that the provisions be revised accordingly.

In their Reply Comments, the Companies responded to NCSEA's claim that the assignment provisions could burden QF development. First, the Companies noted that the provision was very similar to one already included in DEP's Terms and Conditions on file at the Commission since the Sub 136 proceeding. Second, the Companies had not withheld any assignments other than declining to accept a bank as a second counterparty.

The Companies noted that assignment of PPAs is not uncommon, and therefore the provision was intended to protect their customers from the possibility that QF developers may assume a PPA and be unable to fulfill their financial obligations under it.

Conclusion

Based upon its review of the comments in this matter, the Commission finds that the Companies' assignment provision is necessary and appropriate to include in the standard contract. The Commission is not persuaded that this provision is an undue burden on QF development. First, similar language was included, without objection, in the Sub 136 proceeding for DEP. Second, although NCSEA and the Public Staff have argued that the provision potentially constitutes a burden on QF development, there is simply no evidence that this has happened. QF development in North Carolina has been robust, and no party disputed that PPAs do get assigned to third parties. Finally, the Companies have not used the provision in any way to hinder development. Instead, the Companies reported that they have not withheld assignments, other than declining to accept a bank as a second counterparty. For the foregoing reasons, the Commission approves the Companies' provisions on assignment of the PPA without modification.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The Companies included the following provision in its Standard PPA:

> Said Rate Schedule and Terms and Conditions for the Purchase of Electric Power are subject to change, revision, alteration or substitution, either in whole or in part, upon order of said Commission or any other regulatory authority having jurisdiction, and any such change, revision, alteration or substitution shall immediately be made a part hereof as though fully written herein, and shall nullify any prior provision in conflict therewith.
>
> The language above beginning with "Said Rate Schedule" shall not apply to the Fixed Long-Term Rates themselves, but it shall apply to all

> other provisions of the Rate Schedule and Terms and Conditions for the Purchase of Electric Power, including but not limited to Variable Rates, other types of charges (e.g., administrative charges), and all non-rate provisions.

The Companies included similar language in its Schedule PP, again with the exception of long-term fixed rates from the Commission's authority to issue an order amending the PPA and Schedule PP. The Companies also included in their Terms and Conditions that the agreement is subject to change by governmental agencies, but provided that no change may be made in rates or in essential terms and conditions of the contract except by the agreement of the parties to the contract.

NCSEA stated that these provisions were unclear and that they could disrupt settled expectations embodied in an agreement, which would lead to uncertainty and difficulty obtaining financing. NCSEA then requested that the Commission reject the proposed language.

The Public Staff did not raise this issue in either its Initial Comments or its Reply Comments.

In their Reply Comments, the Companies recounted that the Commission had approved language similar to the contested language in this issue in the Sub 136 proceeding. At that time, Section 2 of DEC's Terms and Conditions provided that those rate schedules and service regulations were subject to change by the Commission and that such changes should immediately be part of the QF's contract and should nullify any provision in conflict therein. The sentence that DEC had deleted had included a limitation to changes in the rate schedule to "variable rates only." DEC removed this language because it had appeared overly broad and suggestive that long-term fixed rate contracts would not be subject to change in non-rate terms and provisions. The Companies indicated that DEC had not meant to imply, however, that the long-term fixed avoided cost rates themselves were subject to change during the term of the contract. The Public Staff and the Renewable Energy Group ("REG") had objected and, to respond to their objections, DEC had agreed to include the following:

> The language above beginning with "Said Rate Schedule" shall not apply to the Fixed Long-Term Rates themselves, but it shall apply to all other provisions of the Rate Schedules and Service Regulations, including but not limited to Variable Rates, other types of charges (e.g., facilities charges) and all non-rate provisions.[36]

The Public Staff and REG agreed with this proposal. The Companies stated that the Commission then directed that DEC's contracts from November 1, 2010 until November 1, 2012 be retroactively deemed to have included the sentence. The Companies further reported that no party objected to that retroactive modification of the contracts.

The Companies concluded by stating that their intent is to simply comply with the Commission's decision in the Sub 136 proceeding.

Conclusion

Based on its review of the comments in this proceeding and its Sub 136 Order, the Commission finds that the inclusion of the language that the Companies propose is consistent with prior precedent and the scope of the Commission's authority pursuant to PURPA and the North Carolina General Statutes to issue orders approving standard offers, terms and conditions, and rate schedules related to avoided costs. The Commission further notes the language provides that the long-term fixed avoided cost rates are not subject to change during the term of the contract, thereby providing certainty that those rates will remain fixed, regardless of subsequent Commission action. These

[36] The Companies' Reply Comments at 38.

agreements are, quite simply, subject to the Commission's authority and, pursuant to that authority, certain provisions, such as facilities charges, are subject to change based on Commission action. This works both ways, for the QFs and for the Companies, as shown in the Sub 136 proceeding. Therefore, the Commission concludes that the provisions are reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

In its Initial Comments, NCSEA argued that the Companies proposed adjustments for reactive power were confusing and had the potential to penalize QFs unfairly. NCSEA further questioned conditions that would warrant an Operating Agreement as mentioned in DEP's provision.[37] In its Reply Comments, NCSEA reiterated its earlier statements with respect to conditions that warranted an Operating Agreement and suggested that QFs receive a commensurate credit whenever they supplied reactive power.[38] NCSEA also highlighted the design standard reflected in Section 1.8 of the approved North Carolina Interconnection Agreement that requires a generating unit to maintain a power factor within the range of 95% leading to 95% lagging.[39] NCSEA recognized the difference between this design requirement and the unity power factor operating requirement stated in Schedule PP, but it expressed concern with a QFs' ability to meet possible voltage support requirements as expressed in paragraph 8(b) of the Terms and Conditions while maintaining a unity power factor.

In its Reply Comments, the Public Staff noted that Section 1.8 of the approved North Carolina Interconnection Agreement provides that a utility is obligated to pay the interconnection customer when the utility requests the interconnection customer to

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[37] NCSEA Initial Comments at 58.
[38] NCSEA Reply Comments at 27.
[39] NCSEA Reply Comments at 28.

operate with a power factor outside of the 95% leading to 95% lagging range at the rate the Utility pays its own or affiliated generators for reactive power service within the specified range. The Public Staff recommended that DEC and DEP update their rate schedules to reflect the utilities' obligation to pay an interconnection customer for reactive power that the customer provides or absorbs at the utility's request.

In their Reply Comments, the Companies noted that they revised the power factor provisions to clarify that a QF is expected to operate their generation in a manner that will not adversely impact voltage. QFs without specific Operating Agreements are requested to operate at unity or 100% power factor without either supplying or consuming VARS. This approach, argued the Companies, eliminates potential conflicts with the normal system operations, which could adversely impact service to retail customers in the surrounding area. If the QF supplies reactive power, the Companies explained, it can often conflict with DEC's or DEP's normal operating scheme and cause high voltage conditions. An Operating Agreement may be appropriate for larger QFs with the capability to actively provide direct voltage support. The agreement specifies the ancillary service requirements and the compensation for providing ancillary services as permitted in the QF's interconnection agreement. Such agreements are not appropriate, for smaller generators because DEC or DEP must still install its own capacitors if the QF is not operating during a low voltage event. Thus, the Companies avoid no costs. QFs not operating at a unity power factor as proposed to be charged for VAR consumption or supply as retail customers.

The Companies disputed NCSEA's claim that the proposed power factor provisions were confusing and potentially punitive. The Companies indicated that they are not treating the QFs differently than retail customers that deviate from their power factor requirement. The Companies described NCSEA's comment that providing VARS benefits the Companies as erroneous; the supply of VARs conflicts with the Companies' normally operating schemes and potentially creates higher cost to maintain voltage in the area. The Companies concluded by noting that operating at a unity power factor maximizes the QF's kilowatt production, which is a unit of measure used to compensate QFs for their electricity production; thus, a unity power factor should be desirable to a QF.

Conclusions

The Commission recognizes the importance of reactive power in maintaining area voltage control. Requesting that a QF operate at a unity power factor is reasonable to avoid conflicts with the utility's normal grid operations. As indicated in the Companies' Reply Comments, operating at a unity power factor maximizes the QFs kilowatt-hour production, which is the unit of measure used to compensate the QF for their electricity production; therefore, a unity power factor should be desirable from the QFs' perspective.[40] In cases where the QF is better positioned to control voltage, an Operating Agreement can be executed between the party that specifies compensation for reactive power that the QF provides or absorbs at the utilities' request. Compensation for the supply or consumption of reactive power will be at the rate the utility pays its own or affiliated generators for reactive power service consistent with its Open Access Transmission Tariff as required in the approved North Carolina Interconnection Agreement. Contrary to the Public Staff's Reply Comments, it is not necessary to restate this requirement for compensation in the utility tariffs since it is already adequately

[40] Companies' Reply Comments at 40.

addressed in the approved North Carolina Interconnection Agreement. The Commission therefore finds that the Power Factor Correction provisions proposed by DEC and DEP are just and reasonable and are therefore approved.

FINDINGS AND CONCLUSION FOR FINDING OF FACT NO. 13

The Companies included the following provision in its Rate Schedules:

> Service necessary for the delivery of power from the Seller's generating facilities into the Company's system shall be furnished solely to the individual contracting Seller in a single enterprise, located entirely on a single, contiguous premise.

In its Initial Comments, NCSEA questioned the inclusion of this provision, arguing that it had the potential to be more restrictive than the Companies' half-mile limitation. NCSEA further argued that single, contiguous premise was not defined, and the provision may be contrary to the Commission's 5 MW eligibility threshold.

In their Reply Comments, the Companies disputed NCSEA's argument. The Companies noted that service to a single, contiguous property is a well-established retail service practice and is intended to minimize the cost of providing service to a site, which minimizes the costs passed on to DEC's and DEP's customers. The provision does not preclude the QF's ability to wire its entire site's electrical requirements to a single point of interconnection if its property happens to be bisected by a right of way, for example. The Companies concluded that no change in this provision was necessary.

Conclusions

Based on the foregoing, the Commission finds that the provision proposed by the Companies minimize the costs passed along to their customers by minimizing the costs of providing service to a single site. The provision does not preclude a QF from being able to wire its entire site's electrical requirements to a single point of interconnection. Therefore, the Commission concludes that this provision is reasonable and appropriate and therefore is approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

As a part of its effort to consolidate its tariff structures, the Companies added a new "Reporting Requirements" section to the proposed standard PPA. The purpose of the new provision was to require QFs with capacities of 100 kW or greater, upon request of the utility, to provide their operating schedule to the utility to assist the utility in scheduling its other generation resources. The QF would be required to provide the start time, the time for return to service, the amount of unavailable capacity, and the reason for the outage. DEC and DEP indicated that the reporting requirement was intended to give system operations ample notice of QF operations to allow them to plan generation accordingly, particularly when a QF was experiencing an outage.[41]

During its review of DEC's and DEP's proposal, the Public Staff expressed concern with the difficulty and ambiguity of this reporting requirement and believed that the provision was overly broad. In its Initial Comments, the Public Staff indicated that it believed such reporting may be appropriate for certain facilities; however, the threshold for reporting and the degree of detail associated with the QF's operations, appeared onerous and did not provide clear direction to the QF when it is necessary to report such operations.[42] With the Companies' concurrence, the Public Staff recommended in its Initial Comments that the "Reporting Requirements" provision in the PPA be restated as follows:

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[41] Public Staff's Initial Comments at 54.
[42] Id. at 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.

In its Reply Comments, NCSEA indicated that it did not oppose the reporting requirement as it relates to QF outages, planned or unplanned.[43] NCSEA recognized 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. However, NCSEA expressed concerns regarding the production forecast requirements agreed to by the Public Staff and the Companies. NCSEA argued that while the QF is in the better position to provide information regarding outages, the Companies are in the better position to forecast production for QFs relying on variable resources such as solar, wind and streamflow that require sophisticated meteorological analysis. NCSEA recommended that the Commission reject the proposal as it relates to production forecasting or at a minimum allow any production forecast to be based upon the QF's initial design criteria.[44]

Conclusions

The Commission has considered the arguments raised by the parties and concurs that a Reporting Requirement is appropriate to aid the Companies in scheduling the operation of other generation resources. The Commission agrees that the QF is in the best position to provide its outage schedule and to identify the duration of both planned and unplanned outages. The Commission agrees that for variable resources, such as

[43] NCSEA Reply Comments at 25.
[44] NCSEA Reply Comments at 26.

solar, wind and streamflow, a precise hourly forecast of production is difficult, but such prevision does not appear to be the intent of the Companies' provision. The QF should provide its best estimate of production, but the Commission concludes the QF shall be held harmless if such production estimate is in error due to factors beyond its control such as the availability of solar, wind or streamflow. The Commission agrees that the revised provision proposed by the Companies and the Public Staff is a reasonable compromise to meet the needs of the Companies while not imposing an undue burden on the QF. The Commission therefore concludes that the revised provision tendered by the Public Staff and Companies shall be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

In its Initial and Reply Comments, NCSEA raised several concerns related to the provisions that the Companies had included in their PPAs, Purchase Power Schedules, and Terms and Conditions. These concerns related to Termination Rights and the Right to Terminate for Inability to Deliver, the Deadline for Achieving Commercial Operation and Commencement of Term, and the Inclusion of Certain Terms from the Interconnection Agreements. NCSEA's concerns were mainly that the terms were not clear or were potentially adverse to QF development. The Public Staff agreed with many of NCSEA's specific concerns about the PPAs, Purchase Power Schedules and Terms and Conditions in its Reply Comments.

In their Reply Comments, the Companies indicated that they had settled some of these issues with NCSEA. On September 17, 2015, the Companies filed a letter, which outlined the settlement of these issues with NCSEA. NCSEA agreed to the filing of the letter. The letter indicated the following:

Termination Rights and Right to Terminate Based in Inability to Deliver

The Companies and NCSEA have agreed that, for termination issues that are included in both the interconnection agreements and the PPA, there will be a five (5) day cure period in Section (i) of its Terms and Conditions. For termination issues that are not covered by the interconnection agreement, the Terms and Conditions will contain a 30 day cure period, except for fraudulent or unauthorized use of Company's meter where termination is immediate. The agreed-upon language is as follows:

(i) Company's Right to Terminate or Suspend Agreement - Company, in addition to all other legal remedies, may either terminate the Agreement or suspend purchases of electricity from Seller (l) for any default or breach of Agreement by Seller, (2) for fraudulent or unauthorized use of Company's meter, (3) for failure to pay any applicable bills when due and payable, (4) for a condition on Seller's side of the point of delivery actually known by Company to be, or which Company reasonably anticipates may be, dangerous to life or property, or (5) due to Seller's inability to deliver to Company the quality and/or quantity of electricity mutually agreed to in the Purchase Agreement. Termination of the contract is at the Company's sole option and is only appropriate when the Seller either cannot or will not cure its default or if the Seller fails to deliver energy to the Company for more than six months.

(ii) No such termination or suspension, however, will be made by Company without written notice delivered to Seller, personally or by mail, stating what in particular in the Agreement has been violated, except that no notice need to be given in instances set forth in 1.(i)(2) ~~and 1.(i)(4)~~ above. Company shall give Seller 30 calendar days prior written notice before suspending or terminating the Agreement pursuant to provisions 1.(i)(1), (3), and (5). Company shall give Seller five (5) calendar days prior written notice before suspending or terminating the Agreement pursuant to provision 1.(i)(4).

The Companies and NCSEA have discussed interpretation of (i)(5) above, which provides that the Seller's inability to deliver to the Company the quality and/or quantity of electricity mutually agreed to in the Purchase Agreement is a condition for termination or suspension. The Companies and NCSEA agree that this provision does not mean that if the Seller was unable to deliver due to circumstances beyond its control, such as weather conditions, the Companies would terminate or suspend under this provision. The intent of (i)(5) is to allow for termination or suspension when events or circumstances *within* the Seller's control, e.g. unrepaired equipment, result in the Seller not delivering as mutually agreed to in the Purchase Agreement.

Deadline for Achieving Commercial Operation and Commencement of Term

As discussed in the Companies' Reply Comments, the Companies and NCSEA have agreed that the Companies would clarify that the 30-month deadline for achieving commercial operation can be extended in both their Purchased Power Agreement and their Purchased Power Schedule. Additionally, the Companies agreed that the beginning date of an agreement in the Purchased Power Agreement would occur on the date energy is first generated and delivered rather than the date the Company's facilities are first available. The agreed upon language is as follows:

> Initial Delivery Date (included in the Purchased Power Agreement)
>
> The term of this Agreement shall begin upon the first date when energy is generated by the Facility and delivered to Company and continuing for the term specified in the Rate Schedule paragraph above and shall automatically extend thereafter unless terminated by either party by giving not less than thirty (30) days prior written notice. The extension will be at the Variable Rates in effect at the time of extension. The term shall begin no earlier than the date Company's Interconnection Facilities are installed and are ready to accept electricity from Seller which is requested to be ________________, 20__. Company at its sole discretion may terminate this Agreement on ________________, 20__ (30 months following the date of the order initially approving the rates selection shown above which may be extended beyond 30 months if construction is nearly complete and the Seller demonstrates that it is making a good faith effort to complete its project in a timely manner) if Seller is unable to provide generation capacity and energy production consistent with the energy production levels specified in Provision No. 2 above.

AVAILABILITY (included in the Purchased Power Schedule)

All qualifying facilities have the option to sell energy to the Company on an "as available" basis and receive energy credits only calculated using the Variable Rates identified in this Schedule for the delivered energy. The Variable Energy Credit shall constitute the "as available" avoided cost credit for Non-Eligible Qualifying Facilities. The Fixed Long Term Credit rates on this schedule are available only to otherwise eligible Sellers that establish a Legally Enforceable Obligation on or before the filing date of proposed rates in the next biennial avoided cost proceeding, provided eligible Seller begins delivery of power no later than thirty (30) months from the date of the order approving avoided cost rates in Docket No. E-100, Sub 140, but may be extended beyond 30 months if construction is nearly complete and Seller demonstrates that it is making a good faith effort to complete its project in a timely manner.

Inclusion of Interconnection Terms

The Companies and NCSEA have discussed the Companies' concern that they have some "grandfathered" Sellers that do not have interconnection agreements. Therefore, the Companies and NCSEA agree to inclusion of the interconnection terms in the Terms and Conditions for transparency and clarity. The Companies have included in their Reply Comments a statement that, in the unlikely event of a conflict between the Terms and Conditions and the interconnection agreement, the interconnection agreement will control. Therefore, the Companies' Terms and Conditions will include the following language:

> If Seller is not subject to the terms and conditions of the North Carolina Interconnection Procedures, Forms and Agreements for State-Jurisdictional Interconnection, as approved by the Commission in Docket No. E-100, Sub 101, the following conditions shall apply to Interconnection Facilities necessary to deliver Seller's electricity to Company. Otherwise, the terms and conditions of the North Carolina Interconnection Procedures, Forms and Agreements for State-Jurisdictional Interconnection, as approved by the Commission in Docket No. E-100, Sub 101 govern.

Conclusions

Based on the foregoing, the Commission finds and concludes that the terms that the Companies and NCSEA have agreed upon for inclusion Schedule PP, the PPA and the Terms and Conditions are just, reasonable, in the public interest, and are therefore approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

In their Initial Statements, the Companies supported DNCP's proposal the at the QF complete a simple form that states that the QF is making an offer to sell its output to the facility that sets the date of the Legally Enforceable Obligation. The Companies asserted that the form should provide the date and the docket number of the CPCN it has obtained or the Report of Proposed Construction ("ROPC") it has filed. If the QF has not yet entered into a CPCN or received an ROPC, the QF should bear the responsibility of supplementing the form. The Companies also noted that the forms could be submitted electronically and would be available on the Companies' website. The Companies also noted that unless the Companies decided to stop using the form, or made a material change to it, no additional approvals by the Commission should be necessary.

In its Initial Comments, NCSEA objected to the proposed Notice of Commitment to Sell Form ("Notice") offered by DNCP. NCSEA indicated that the form was too complicated and that it contained provisions that were contrary to law and precedent. In particular, NCSEA argued that the form contained circumstances under which the Notice would terminate. One of the circumstances NCSEA identified was when a QF that is eligible for the standard offer rates and contract terms does not execute a PPA prior to the date set by NCUC for the filing of updated rates and contracts. Another circumstance was if a QF did not execute a PPA within six months after DNCP submitted the PPA to the QF, unless the PPA was subject to arbitration. NCSEA argued that PPA negotiation can take more than six months and there is no federal precedent for the termination of a LEO.

NCSEA offered its own form as a means, but not an exclusive, means for establishing a commitment. NCSEA also indicated that the form should be available on the Companies' websites, standard instructions for completing it should be provided to the QF and that the form should be submitted electronically, but also by mail, etc. Finally NCSEA concluded that the utilities should be required to obtain Commission approval before changing the form.

In its Reply Comments, NCSEA again stated that DNCP's Notice includes a section on the termination or expiration of a commitment, which NCSEA asserted was premature and outside of the FERC and Commission guidance. For that reason, NCSEA indicated that the Notice would lead to additional disputes at the Commission.

As for instructing the QFs about the form, the Public Staff in its Initial Comments recommended that each utility, in the notification that it sends out to an interconnection customer confirming receipt of an interconnection request include a statement as follows:

> The submission of an interconnection request does not constitute an indication of a customer's commitment to sell the output of a facility to the utility. For information on submitting a legally enforceable obligation ("LEO") form or requesting a power purchase agreement ("PPA"), please see the following website.

The Public Staff also agreed with the items that the Companies had proposed including in the form, with the addition of information regarding termination of the LEO. It further indicated that a QF that has obtained a CPCN and established a LEO should have a commercially reasonable period of time, not less than thirty days after being presented with an executable PPA from the utility, to execute the PPA before rates expire.

In its Reply Comments, DNCP submitted a revised Notice. DNCP disagreed with NCSEA's contention that use of the Notice should be permissive and responded that the entire point of developing the Notice in the first place was to increase simplicity and transparency. If the QF could opt to use the Notice or some other type of communication, then the disagreements about the commitment to sell would simply begin anew. Moreover, DNCP and the Public Staff agreed that the utilities should publicize this Notice so that QFs will know of its use. Thus, concluded DNCP, there is no reason to make using the Notice an option rather than a requirement.

DNCP also defended the clarity of its form, in that it addresses matters related to LEOs that have been subject to dispute, leading to Commission proceedings and delayed PPAs. DNCP indicated it would have the Notices located on a section of its website related to Interconnection Agreements and PPAs. With respect to LEO termination, DNCP, consistent with the suggestion of the Public Staff, included a provision that stated that the LEO would terminate if the QF does not execute a PPA within 30 days of the Company's delivery of an executable PPA. An executable PPA, DNCP explained, is one that contains all the information necessary for execution and that the Company has requested be returned. For QFs that are not eligible for the standard rate schedule, DNCP proposed to clarify the length of the potential extension of time allowed to execute a PPA related to the tendering of an Interconnection Agreement.

In its Reply Comments, the Public Staff noted that it had reviewed the form submitted by DNCP and found it resolved its specific issues. The Public Staff noted that other issues among NCSEA, DNCP, the Companies and the Public Staff remained and additional conversations were planned.

On September 10, 2015, the Public Staff filed a letter in this Docket explaining that DEC, DEP, DNCP, NCSEA and the Public Staff had reached agreement on the contents of the first four sections of DNCP's Notice, and believe they can be adapted for use by DEC and DEP. The parties did not agree, however, on the fifth section of the Notice, which includes acknowledgments of when the LEO is established, or the sixth section, which sets out the circumstances under which the Notice terminates. The parties agreed to address these issues in their proposed orders for this proceeding.

On September 17, 2015, the Companies filed a letter on behalf of them and DNCP indicating that they had come to agreement on Section 5 of the Notice. In particular, the Companies believe that a Notice should attach to the facility that received a CPCN or ROPC, not the owners. Section 5 and Section 6 also generally provide that a Notice should not go on indefinitely. The letter explained that because DNCP and the Companies have established different internal procedures for QFs that are larger than 5 MW, the Companies forms should be allowed to reflect those differences. The letter also reaffirmed that DEC and DEP will make the Notice accessible on-line.

Conclusions

As noted by the Public Staff, it has been the FERC's long-standing practice to "leave to state commissions the issue of when and how a legally enforceable obligation is created." [45] Therefore, both the initiation of a LEO and, contrary to NCSEA's assertion about FERC precedent, termination of a LEO, is within the Commission's jurisdiction. The Commission is not required to look to FERC precedent to establish this Notice or its expiration or termination provisions.

In addition, the Commission concludes that use of such Notice should be

[45] Public Staff Initial Comments, at 60.

mandatory. It agrees with the comments of DNCP that, by making use of the Notice but one way to communicate a Notice of Commitment to Sell, development of this Notice does not achieve any clarity or certainty. Unless the Notice is mandatory, disputes will clearly continue.

The Commission concludes that based on the agreement of the parties that the first four sections of the Notice are acceptable and in the public interest. The Commission also approves of the inclusion of Section 5 from the DNCP and the Companies' proposed Notice. Section 5 is intended to clarify the acknowledgments both for QFs with capacity of 5 MW and less and for QFs greater than 5 MW ("large QFs"). As the Commission concluded in its March 6, 2015 *Order of Clarification* in this docket, with respect to large QFs, the Utilities should use the most up-to-date data to calculate avoided cost rates. Therefore, the establishment of a LEO is vital for the Utilities to determine what rate schedule the smaller QF is eligible for or to calculate the rates using "up-to-date" data for large QFs. Section 5(a)-(c) outlines the interplay of the CPCN and the Notice to clearly explain the requirements to establish a LEO. New Section 5(d)-(f) explains that the Notice is not perpetual. An PPA with one of the Utilities replaces the need for the LEO. If a PPA is terminated or expires, then the relevant Utility should not be forced to assume the QF still intends to sell to it, and the QF should not be able to revive a potentially long-past given Notice to obtain rates more advantageous to it than the rates that are currently in effect. Therefore, the Notice does not survive a terminated or expired PPA, unless the termination is determined to be improper as outlined in Section 5(d). One of the purposes of the LEO is to entitle the QF to avoided cost rates calculated at the time of the LEO is established. Allowing the Notice to carry on indefinitely, even after a PPA has been executed and then terminated or has expired, would defeat the purpose of the LEO, and allow the QF to claim a LEO years after the relevant PPA. Such a LEO would enable the QF to enter into a long-term fixed rate contract that would not be aligned to the current avoided costs of the Utilities, to the potential detriment of the Utilities' customers.

Section 5(f) requires acknowledgement that the Notice applies to the proposed facility that is identified in the CPCN or in the ROPC. In the Utilities' experiences, the generating facilities have been subject to "flipping," which means one QF developer assigning or selling the facility to another. Changes in ownership can make tracking a Notice administratively impossible. Attaching the Notice to the facility described in the CPCN or ROPC, and not to the owners of the facility, accomplishes the Commission's goals by linking a CPCN (or RPOC) and a commitment to sell from that facility to the establishment of a LEO. Therefore, based on the above, the Commission agrees with and approves the respective Notices agreed to and submitted by DNCP and the Companies.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

In support of its Reply Comments, NCSEA submitted an affidavit of Ben Johnson, PH.D. on August 7, 2015. The filing of this affidavit was improper under the circumstances and, therefore, the Commission will not consider it. Under N.C. Gen. Stat. § 62-68 affidavits may be proposed to be used as evidence "prior to a hearing or a continued hearing." Prior to the submission of proposed avoided cost rates by the utilities, the Commission stated that it did not intend to conduct another full evidentiary hearing for the purpose of receiving expert testimony.[46] The Commission further stated

[46] *Order Establishing Procedural Schedule and Scheduling Public Hearing*, Docket No. E-100, Sub 140, issued Jan. 8, 2015 at 2.

that this procedure is appropriate given the amount of evidence already presented in Phase One.[47] NCSEA clearly submitted Dr. Johnson's affidavit as a way of supporting its Reply Comments by expert testimony, but this submission is outside of the Commission's procedure. Had Dr. Johnson wanted to present testimony or comments in this docket, he had the option of testifying as a public witness at the May 19, 2015 public hearing or intervening as a party. As he did not do either, the Commission will not consider his affidavit in making its determinations in this docket.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC and DEP shall offer long-term levelized capacity rates and energy rates for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in N.C. Gen. Stat. § 62-3(27) contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of the or more years shall include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. DEC and DEP shall offer their standard five-year levelized rate option to all other QFs contracting to sell 3 MW or less capacity.

[47] Id.

2. That DEC and DEP shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process, (b) negotiating a contract and rates with the utility, or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates shall have the option of selling into the wholesale market. The exact points at which an active solicitation is regarded as beginning and ending for these purposes shall be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

3. That the Utilities shall post the LEO Form(s) as approved herein to the sections of their respective websites dedicated to informing developers about the process for obtaining a PPA as soon as practicable after the date of this Order, and that the

LEO forms(s) as approved herein are, commencing with the date of this Order, the only method that a QF may use to commit to sell to a utility. We also direct that the Utilities implement the suggestion of the Public Staff with regard to informing parties seeking interconnection of the distinction between that process and the QF commitment process by including the language proposed by the Public Staff in their notices of confirmation of interconnection request receipt and on their interconnection websites.

4. That the rate schedules and standard contract terms and conditions proposed in this proceeding by DEC and DEP are approved, except as otherwise discussed herein. The Utilities shall file new versions of their rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order, to become effective 15 days after the filing date unless specific objections to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of ________, 2015.

NORTH CAROLINA UTILITIES COMMISSION

Gail S. Mount, Chief Clerk