NC SUSTAINABLE
ENERGY ASSOCIATION

September 4, 2019

Ms. Janice Fulmore
Deputy Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Raleigh, NC 27603

Re: Docket No. E-100, Sub 158
In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2018
Proposed Order of the North Carolina Clean Energy Business Alliance, the North Carolina Sustainable Energy Association, and the Southern Alliance for Clean Energy

Dear Ms. Fulmore,

In connection with the above-referenced docket, please find enclosed for filing the Proposed Order of the North Carolina Clean Energy Business Alliance, the North Carolina Sustainable Energy Association, and the Southern Alliance for Clean Energy.

Please let me know if you have any questions or if there are any issues with this filing.

Respectfully yours,

/s/ Peter H. Ledford

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing documents by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 4th day of September, 2019.

/s/ Peter H. Ledford

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	))))))))	**PROPOSED ORDER OF THE NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE, THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, AND SOUTHERN ALLIANCE FOR CLEAN ENERGY**

BY THE COMMISSION: This is the 2018 biennial proceeding held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C. 824a-3, and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions,[1] which delegated to this Commission certain responsibilities for determining each utility's avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings are also held pursuant to N.C.G.S. § 62-156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in N.C.G.S. § 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by FERC establish the responsibilities of FERC and state regulatory authorities, such as this

[1] Order No. 69, Docket No. RM79-55, FERC Stats. & Regs. 30, 128 (1980); *see also* 45 Fed. Reg. 12,214 (1980).

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

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

With respect to electric utilities subject to state jurisdiction, 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 FERC's rules.

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

This proceeding also follows the mandate of N.C.G.S. § 62-156, which was enacted by the General Assembly in 1979. This statute provides that "no later than March 1, 1981, and at least every two years thereafter" the Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed therein. Such standards generally approximate those prescribed in FERC regulations regarding factors to be considered in the determination of avoided cost rates. House Bill 589 ("H.B. 589"), S.L. 2017-192 made significant revisions to the state implementation of PURPA, while still leaving a number of implementation issues to the Commission for consideration in these biennial proceedings.

On June 26, 2018, the Commission issued its Order Establishing Biennial Proceedings, Requiring Data, and Scheduling Hearing. Pursuant to the Order, Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, LLC (DEP) (together, Duke Energy); Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (Dominion); Western Carolina University (WCU); and Appalachian State University, d/b/a New River Power and Light (New River) were made parties to these proceedings.

The following parties filed Petitions to Intervene that were granted by the Commission: North Carolina Sustainable Energy Association (NCSEA), North Carolina

Clean Energy Business Alliance (NCCEBA), Carolina Utility Customers Association, Inc. (CUCA), Ecoplexus, Inc. (Ecoplexus), Southern Alliance for Clean Energy (SACE), NC Small Hydro Group (Hydro Group), Cube Yadkin Generation LLC (Cube Yadkin), and NC WARN, Inc. (NC WARN). Participation of the Public Staff was recognized pursuant to N.C. G.S. § 62-15(d) and Commission Rule R1-19(e).

On November 1, 2018, DENC filed its Initial Statement and Exhibits and its confidential avoided cost information. On November 1, 2018 Duke Energy filed a Joint Initial Statement and Exhibits and confidential avoided cost information. On November 1, 2018 WCU and New River filed Joint Comments and Proposed Rates.

On December 31, 2018, the Public Staff filed Motion for Extension and Revised Procedural Schedule. On January 4, 2019 NCSEA filed a Response to the Public Staff's Motion for Extension and Revised Procedural Schedule and Motion for Modified Procedural Order on Testimony. On January 10, 2019, DEC and DEP filed a Joint Response to NCSEA's Response to the Public Staff's Motion for Extension and Revised Procedural Schedule and Motion for Modified Procedural Order on Testimony. On January 25, 2019, the Commission issued an Order on Procedural Schedule and Requiring Report.

On February 8, 2019, NC WARN filed Initial Comments. On February 12, 2019, Hydro Group, Cube Yadkin, NCSEA, and SACE each filed Initial Comments. On February 13, 2019, the Public Staff filed Initial Comments.

On or before February 20, DEC, DEP, and DENC filed Affidavits of Publication of Notice of Hearing, and the public hearing was held on February 19, 2019, as scheduled.

On March 7, 2019, DENC filed Revised Proposed Standard Offer Avoided Cost Rate Schedules. On March 2014, 2019, DENC filed a corrected version of the Revised

Proposed Standard Offer Avoided Cost Rate Schedules.

On March 27, 2019, the Public Staff, DENC, Hydro Group, NCSEA, Duke Energy, and SACE each filed Reply Comments.

On April 10, 2019 DEC and DEP filed a Joint Status Report.

On April 18, 2019, Duke Energy and the Public Staff filed a Stipulation of Partial Settlement regarding rate design.

On April 24, 2019, the Commission issued an Order Scheduling Evidentiary Hearing and Establishing Procedural Schedule. The Commission scheduled an evidentiary hearing for the week of Monday, July 15 on discrete issues specified in the Order.

On May 21, 2019 DENC filed the Direct Testimony of Bruce E. Petrie; DEC and DEP filed the Direct Testimony and Exhibits of Glen A. Snider, Steven B. Wheeler, David B. Johnson, and Nick Wintermantel; and DEC and DEP filed a Stipulation of Partial Settlement Regarding Solar Integration Services Charge between and among DEC, DEP, and the Public Staff.

On June 14, 2019, the Commission issued an Order Requiring Supplemental Testimony and Allowing Responsive Testimony.

On June 21, 2019, NCSEA filed the Direct Testimony of Ben Johnson, R. Thomas Beach, and Carson Harkrader; the Public Staff filed the Testimony of Jeff Thomas and John R. Hinton; and SACE filed the Direct Testimony and Exhibits of James Wilson and Brendan Kirby.

On June 25, 2019, DENC filed the Supplemental Testimony of James M. Billingsley; and DEC and DEP filed the Supplemental Testimony of Glen A. Snider.

On July 3, 2019 SACE filed the Responsive Testimony and Exhibits of Devi Glick;

DEC and DEP filed the Rebuttal Testimony of Glen A. Snider, Steven B. Wheeler, David B. Johnson, and Nick Wintermantel; DENC filed the Rebuttal Testimony of Bruce E. Petrie; the Public Staff filed the Testimony of Dustin Metz; and NCSEA filed the Responsive Testimony and Exhibits of Tyler Norris. On July 5, 2019, Ecoplexus filed the Supplemental Testimony of Michael R. Wallace.

Following the evidentiary hearing, Duke Energy filed Late Filed Exhibits 1-4 on August 2, 2019.

In addition to the foregoing, there were other motions, orders, and filings not specifically mentioned which are matters of record.

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

FINDINGS OF FACT

1. The Astrapé *Ancillary Service Study*, relied on by Duke Energy in this proceeding, uses a methodology that has not been adequately tested; relies on a reliability metric that fails to approximate conformance with NERC standards; overstates solar variability; inappropriately models DEC and DEP as physical islands; and has not been subject to a Technical Review Committee or peer review.

2. Duke Energy's historical reserve requirements demonstrate that the *Ancillary Service Study* does not accurately reflect Duke Energy's actual operational practices and does not accurate quantify the costs of integrating solar on to the grid.

3. Duke Energy did not incorporate potential benefits associated with solar QF generation.

4. The Stipulation entered into by Duke Energy and the Public Staff regarding the proposed Solar Integration Services Charge ("SISC") relied on the *Ancillary Service*

Study.

5. It is inappropriate to approve Duke Energy's proposed ancillary services charge or the related Stipulation at this time, given concerns regarding the underlying *Ancillary Service Study*, because Duke Energy has not considered or quantified potential benefits associated with solar, and because the proposed charge was not developed through an appropriate stakeholder process or with adequate independent technical review.

6. Dominion Energy North Carolina did not incorporate potential benefits associated with solar QF generation.

7. Battery storage can be used to smooth the profile and/or shift timing of QF energy production. If battery storage is used to smooth a QF's energy production profile, it can reduce solar volatility and mitigate or eliminate any need for additional ancillary service requirements.

8. The Stipulation entered into by Duke Energy and the Public Staff regarding the proposed SISC cannot be approved because it does not adequately define how innovative QFs could avoid the Solar Integration Charge.

9. Duke Energy and the Public Staff's Rate Design Stipulation relies on Astrapé's 2016 Resource Adequacy Studies and *Solar Capacity Value Study* to determine the avoided capacity rate design. Intervenors have critiqued Astrapé's 2016 Resource Adequacy Studies and the *Solar Capacity Value Study* in this proceeding and in Duke Energy's Integrated Resource Planning proceedings, raising concerns that flaws in the studies result in inaccurate and improper capacity rates and rate design.

10. In particular, the *Solar Capacity Value Study* relies on Astrapé's 2016 Resource Adequacy Studies, which overstate the risk of very high loads under extreme

cold; assume demand response will continue to be summer-focused despite identifying more resource adequacy risk in the winter; and overstate risk of load year-round due to unrealistic economic load forecast uncertainty assumptions.

11. There are multiple unresolved issues related to Duke Energy's reserve margin calculations and load forecast methodology, which have not been resolved in this proceeding. The Commission's 2018 IRP Order issued on August 27, 2019 has scheduled an oral argument to address these issues on January 8, 2020. Therefore, at this time the Commission lacks sufficient evidence to determine the reasonableness of the *Solar Capacity Value Study*.

12. Lacking sufficient evidence regarding the reasonableness of the *Solar Capacity Value Study* the Commission lacks sufficient evidence at this time to determine that Duke Energy's seasonal and hourly allocations of capacity payments are reasonable and appropriate.

13. The Rate Design Stipulation's language providing that it is "reasonable and appropriate for the Companies' seasonal and hourly allocations of capacity payments to be based on the loss of load risk identified in the Astrapé Solar Capacity Value Study" lacks sufficient evidentiary support at this time.

14. Because it is based on the Astrapé Solar Capacity Value Study, Duke's updated avoided energy rate design proposal lacks sufficient evidentiary support at this time.

15. For the purpose of determining capacity payments, it is unreasonable for Duke Energy to assume demand response will continue to be summer-focused despite identifying more resource adequacy risk in the winter.

16. In the absence of evidence on the record regarding whether or not nuclear uprates constitute a capacity expansion that could be avoided by a QF, the Commission declines to accept Duke Energy's assumption that the QFs could not help avoid the need for future nuclear uprates.

17. It is appropriate to calculate avoided costs utilizing a presumed in-service date of December 31, 2021.

18. It is appropriate to include the costs for firm natural gas transportation to a combustion turbine when calculating avoided capacity rates.

19. It is inappropriate to utilize brownfield sites when calculating the cost of new peaking generation when the utilities' integrated resource plans do not call for new peaking generation to be installed at brownfield sites.

20. Dominion's proposed annual capacity payment cap should be rejected.

21. QFs that file a notice with the utility at least 3 years before their current PPA expires indicating that the QF is committing to continuously provide capacity and energy (without interruption) after the current contract expires – and specifying the length of that capacity commitment – should continue to receive capacity payments when they enter into a subsequent, new PPA. Additionally, existing QFs should have the opportunity, at their option, to compete to meet any capacity needs after the expiration of their current PPAs.

22. Duke Energy's proposal to rely 2018 IRP commodity price forecast using 10 years of forward market pricing for natural gas for calculating its avoided cost rate is inappropriate.

23. Dominion's approach to calculating natural gas pricing, which uses 18

months of natural gas forward pricing, 18 months of blending natural gas forward pricing, and ICF pricing beyond 36 months to calculate avoided energy costs, is appropriate and reasonable, and should be utilized by all the Utilities.

24. Dominion's use of the Black-Scholes model for calculating a fuel hedge value is appropriate and reasonable.

25. Duke Energy's proposal to eliminate the fuel price hedge value because it is offset by a "Put Option" is inappropriate. Duke Energy has not calculated the value of the alleged "Put Option" and has provided no evidence that the value of the "Put Option" offsets the fuel hedge value quantified by the Black-Scholes model.

26. The Utilities' Performance Adjustment Factor ("PAF") proposals do not adequately reflect historical data regarding the distribution of summer and winter peaks and as a result understate the contribution to capacity QFs make during shoulder months. Historical data supports the addition of June, September, and December, and March in the Utilities' PAF calculations.

27. Solar QFs continue to provide line loss avoidance benefits and Dominion Energy's proposal to eliminate the line loss adder is inappropriate. While the historical 3% line loss adder may not accurately reflect the line loss avoidance benefits solar QFs currently provide, complete elimination of the adder also fails to accurately reflect line loss avoidance benefits.

28. Duke Energy's continued inclusion of a line loss adjustment for distribution connected QF power is appropriate and reasonable.

29. The Public Staff should convene stakeholders to calculate the value of market price suppression in North Carolina caused by new renewable energy generation.

30. It is appropriate at this time for the Utilities should offer a real-time avoided cost option to QFs, and the Utilities should include a granular, 12x24 rate design as an option for QFs in their 2020 avoided cost filings.

31. It is appropriate for Dominion to offer avoided cost rates that contain three seasons with three rate periods each.

32. The standard offer PPA contracts approved in Docket No. E-100, Sub 136, Sub 140, and Sub 148 do not limit DC rating, the addition of battery storage or other equipment modifications, or changes in the quantity of energy output or the timing of energy delivery. The only relevant limitations contained in some of those documents are on exceeding the stated AC capacity of the facility or modifying the estimated annual energy generation (which is not the same thing as a prohibition on exceeding a maximum energy generation value, which does not appear in any of the documents).

33. Duke's proposed changes to existing standard offer PPA and terms and conditions are not clarifying in nature but rather alter the legal rights and obligations of the QF and Duke.

34. Many of Duke's proposed changes to their standard offer PPA and Terms and Conditions are unnecessary and inappropriate and would disincentivize the addition of battery storage.

35. The prospective modifications to Duke Utilities standard offer PPAs and Terms and Conditions proposed by NCSEA and NCCEBA in Exhibit A to their post-hearing brief are reasonable and should be adopted.

36. The Commission adopts the proposal of NCSEA and NCCEBA that any storage additions to committed QFs (i.e. those with enforceable LEOs or executed PPAs)

be compensated at the avoided cost rate in effect when the QF's interconnection agreement is amended to include the storage addition.

37. The Commission finds that it is good public policy to support the advancement of battery storage technologies in North Carolina.

38. Duke's proposed Energy Storage Protocol for standard offer PPAs should be approved until the stakeholder negotiations concerning a similar protocol for use in CPRE Tranche 2 have been concluded.

39. The Commission does not adopt Duke's proposed definition of "Nameplate Capacity," the proposed definition of "Existing Capacity," and the proposed definition of "Material Alteration."

40. The Commission adopts NCSEA and NCCEBA's proposed inclusion and definition of "maximum energy production."

41. The Commission finds that prior Dominion standard offer PPAs also do not contain a limit on DC capacity or annual energy output and do not prohibit or require Dominion's approval for modifications to the QF facility or shifting the time of energy delivery, including the addition of storage.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 1-5 AND 7-8

<u>SUMMARY OF THE EVIDENCE</u>

In its E-100, Sub 140 Order, the Commission wrote that "integration of solar resources into a utility's generation mix results in both costs and benefits, many of which may be appropriate for inclusion in a utility's avoided cost calculations."[2] The Commission

[2] *Order Setting Avoided Cost Input Parameters*, p. 60, Docket No. E-100, Sub 140 (December 31, 2014) ("*Sub 140 Phase I Order*").

further determined that inclusion of solar integration costs and benefits in avoided cost calculations would only be appropriate "when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained."[3] In the *Sub 148 Order*, the Commission concluded that it was "appropriate for utilities to propose schedules specific to QFs that provide intermittent non-dispatchable power, if the Utilities' cost data demonstrated marked differences in the value of the energy and capacity provided by these QFs."[4] Duke Energy has relied on the language of the Commission's *Sub 148 Order* to seek justification for a proposed SISC.[5] Duke Energy retained Astrapé Consulting to perform an *Ancillary Services Study* which attempted to quantify the cost of solar integration on the DEC and DEP systems at increasing levels of solar penetration, but the study and proposed charge raised a number of concerns from intervenors.

<u>*Ancillary Service Study* Methodology</u>

In its initial filings, Duke Energy stated that "the Companies have determined that the costs avoided by growing levels of solar QFs that provide intermittent, non-dispatchable power is markedly different from integrating firm power" and proposed a SISC to reflect the cost of integrating solar resources on the system.[6] The Companies proposed a \$1.10/MWh charge in DEC and a \$2.39/MWh charge in DEP based on the *Ancillary Service Study*'s predictions regarding integration costs. The Companies proposed

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[3] *Id.* at 61.
[4] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, p. 98, Docket No. E-100, Sub 148 (October 11, 2017) ("*Sub 148 Order*").
[5] Tr. Vol. 2, p. 77, l. 12 – p. 78, l. 6.
[6] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits*, p. 33, Docket No. E-100, Sub 158 (November 1, 2018) ("*Duke Initial Statement*").

that the SISC would initially only apply to new solar generators (including QFs that establish a LEO and commit to sell power under the avoided cost rates established in this proceeding), and as existing contracts expire and new contracts are executed, the SISC would apply to all solar QFs uniformly.[7]

In its initial comments, and through an expert report authored by witness Brendan Kirby, SACE raised several methodological problems with the *Ancillary Service Study*. SACE took issue with the *Ancillary Service Study*'s modeling of DEC and DEP as physically isolated power systems; reliance on LOLE metrics historically used for long-term utility planning rather than for assessing real-time system reliability; and scaling of solar plant intra-hour variability data in a way that failed to accurately reflect geographic diversity benefits of solar power.[8] NCSEA also critiqued the *Ancillary Service Study* for assuming that DEC and DEP operate as islands; failing to consider how participation in an energy imbalance market ("EIM") would reduce the costs of integration; assuming QFs would be incapable of supplying beneficial ancillary services; and failing to incorporate any solar integration benefits, contrary to the directive in the Sub 140 proceeding that both costs and benefits must be accounted for.[9] In initial comments, the Public Staff stated that it "generally agrees" with the basic premise of the *Ancillary Service Study* and with Duke Energy's assertion that intermittent and non-dispatchable resources have an impact on system operations, including cost.[10] However, the Public Staff noted several concerns with

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[7] *Id.* at p. 34.
[8] *Initial Comments of the Southern Alliance for Clean Energy*, p .5, Docket No. E-100, Sub 158 (February 12, 2019) ("*SACE Initial Comments*"); *id.* at Attachment A.
[9] *NCSEA's Initial Comments*, pp. 32-34, Docket No. E-100, Sub 158 (February 12, 2019). *Id.* at Attachment 2, p. 5 ("Beach Affidavit").
[10] *Initial Statement of the Public Staff*, p. 34, Docket No. E-100, Sub 158 (February 12, 2019) ("*Public Staff's Initial Comments*").

the modeling inputs used in the *Ancillary Service Study*, specifically Duke Energy's proposal that the SISC "refresh" every two years as Duke Energy updates inputs to the *Ancillary Service Study*; the Study's modeling of DEC and DEP as load islands; the Study's use of a "no solar" scenario as a benchmark for system reliability despite the presence of significant utility-owned solar on the grid; the use of only on year of historical data to determine the benefits of solar fleet diversity; and the study's failure to account for ancillary services other than load following reserves.[11]

Use of $\text{LOLE}_{\text{FLEX}}$ Metric

In its initial comments, SACE critiqued the *Ancillary Service Study*'s use of the $\text{LOLE}_{\text{FLEX}}$ metric for predicting the amount of operating reserves necessary to integrate increasing levels of solar penetration of the DEC and DEP systems.[12] SACE stated that the LOLE metric, while a well-accepted approach for long-term resource adequacy planning, is inappropriate for determining a system's ability to conduct day-to-day operations in a reliable manner.[13] SACE asserted that the $\text{LOLE}_{\text{FLEX}}$ metric bears no relationship with the NERC balancing standards that DEC and DEP actually operate to, and was therefore inappropriate for calculating a SISC based on compliance with NERC balancing standards.[14]

In reply comments Duke Energy asserted that its use of the $\text{LOLE}_{\text{FLEX}}$ metric to measure system flexibility by testing whether or not the system can meet net load ramps on a 5-minute basis was not meant to measure NERC reliability regulations, but to measure

[11] *Public Staff's Initial Comments*, pp. 36-37.
[12] *SACE Initial Comments*, p. 5. *Id.* at Attachment A.
[13] *SACE Initial Comments*, p. 5, n. 11.
[14] *SACE Initial Comments*, p. 5.

"much more serious infractions."[15] Duke Energy asserted that while the metric of 0.1 $LOLE_{FLEX}$, which requires the system to maintain enough ramping capability to match 5-minute load ramps in all but one period every 10 years, is "admittedly subjective" the fact that this requirement was imposed in the base case and in all cases with higher solar penetration was more important than the metric itself.[16]

In his direct testimony, Duke Energy Witness Nick Wintermantel confirmed that the "LOLE metric is traditionally used for IRP purposes."[17] Witness Wintermantel also stated that while the $LOLE_{FLEX}$ metric was not a NERC balancing standard, it was "a measure of the system's ability to satisfy net load obligations assuming the net load is known five minutes before it materializes."[18] Witness Wintermantel also asserted that "any $LOLE_{FLEX}$ event should be viewed as a substantial violation of a system's obligation to manage its own load."[19]

In his direct testimony, SACE Witness Brendan Kirby articulated his extensive experience related to power system operations and reliability standards, which included fifteen years at the Oak Ridge National Laboratory as a senior power systems researcher, fifteen published papers on ancillary services, and service as the FERC representative to NERC.[20] Witness Kirby critiqued the *Ancillary Service Study*'s conclusion that integration costs would increase exponentially as solar penetration increases, stating that this flawed

[15] *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments*, p. 96, Docket No. E-100, Sub 158 (March 27, 2019) ("*Duke Reply Comments*").
[16] *Id.* at p. 97.
[17] Tr. Vol. 4, p. 62, ll.19-21.
[18] *Id.* at p. 64, ll. 13-21.
[19] *Id.* at p. 64, ll. 21-23.
[20] Tr. Vol. 5, p. 169-72.

conclusion arose from the use of inappropriate reliability metrics rather than exponentially increasing physical balancing requirements.[21] Witness Kirby further emphasized that while the LOLE metric is appropriate for long-term generation planning, it is inappropriate for short-term balancing conditions because "a 5-minute imbalance will not result in the need to shed firm load or a blackout."[22] Witness Kirby also compared the $LOLE_{FLEX}$ metric to the NERC Balancing Standards, CPS1 and BAAL, and explained that neither standard requires Duke Energy to balance load as stringently as the self-imposed $LOLE_{FLEX}$ metric used in the *Ancillary Service Study*.[23] As a result, Witness Kirby concluded, the *Ancillary Service Study* inflates the balancing requirement beyond what is physically necessary, and then passes on the cost of conforming to this unrealistically stringent standard onto QFs in the form of the SISC.[24]

In his rebuttal testimony, Witness Wintermantel stated that Witness Kirby's critiques of *Ancillary Service Study*'s use of the $LOLE_{FLEX}$ metric overlook the fact that the model assumes perfect foresight in advance of each 5-minute time step.[25] Given that system operators never have perfect foresight, Witness Wintermantel stated that the model should attempt to carry enough reserves to match the 0.1 $LOLE_{FLEX}$ metric, knowing that in real-world conditions many more deviations would occur.[26] Witness Wintermantel further asserted that because the operating reserves the *Ancillary Service Study* predicts to be necessary to meet the 0.1 $LOLE_{FLEX}$ metric are comparable to historical reserves

[21] *Id.* at p. 176, ll. 11-17.
[22] *Id.* at p. 178, ll. 7-14.
[23] *Id.* at p. 180, l. 60 – p. 181, l. 9.
[24] *Id.* at p. 181, ll. 6-9.
[25] Tr. Vol. 4, p. 87, ll. 8-16.
[26] *Id.*

provided by DEC and DEP, "future compliance with the NERC CPS1 and BAAL standards is expected to be consistent with historical compliance."[27] When asked about comparing the *Ancillary Service Study's* predictions to historical reserves Witness Wintermantel admitted that Astrapé had not done such a comparison for any year but 2015, which was compared to the baseline "no solar" scenario.[28]

At the hearing, Witness Kirby explained that the Witness Wintermantel's focus on the perfect foresight condition of the *Ancillary Service Study* was a "red herring" because the "event" that triggers an increase in load following reserves for the model, one failure of the system to follow net load given 5-minute ahead perfect foresight, does not actually result in a loss of load or a NERC reliability standard violation.[29] Witness Kirby explained that absent the perfect foresight condition the *Ancillary Service Study* may overstate necessary reserves even more dramatically, but even with the perfect foresight condition, the driver of the model is a "violation" of a requirement that is not based on or related to any NERC reliability requirements.[30] Witness Kirby also testified that a power system connected to the Eastern Interconnection, as DEC and DEP are, would be perfectly reliable so long as it meets NERC standards.[31] Witness Wintermantel agreed that the NERC reliability standards are sufficiently protective of system reliability.[32] Witness Kirby also explained that if a utility over-complies with NERC standards by carrying significantly

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[27] *Id.* at p. 88, l. 20 – p. 89, l. 2.
[28] *Id.* at p. 119, l. 10 – p. 120, l. 2.
[29] Tr. Vol. 6, p. 90, ll.15-20 ("[the LOLE metric] is completely inappropriate because the violation, while it does result in loss of load under resource adequacy, in this case it does not result in loss of load... it doesn't even result in a BAAL violation.").
[30] *Id.*
[31] Tr. Vol. 4, p. 217, l. 20 – p. 218, l. 18.
[32] *Id.* at p. 163, ll. 6-8.

more operating reserves than necessary it is wasting ratepayers' money.[33] After Witness Wintermantel and Witness Kirby were both recalled by the Commission to provide further testimony, Witness Wintermantel acknowledged, in response to Commission questions, that the premise of the *Ancillary Service Study* is that if a resource capacity analysis indicates that DEC and DEP have sufficient operating reserves to match expected demand, they are likely to meet NERC reliability standards as well.[34] Witness Wintermantel then stated that "when we increase operating reserves, we are going to lower NERC imbalances. When we increase operating reserves, we're also going to lower $LOLE_{FLEX}$. They are correlated."[35] When asked what kind of testing had been conducted to determine the strength of the alleged correlation, Witness Wintermantel pointed to the comparison of the base case to 2015 historical operating reserves, and the sensitivity testing privately conducted for the Public Staff.[36] Witness Wintermantel admitted that no information regarding the "post-processing techniques" used to conduct sensitivity analysis had been introduced into the record.[37]

In response to questioning suggesting that the methodology used by the Ancillary Service Model, and the $LOLE_{FLEX}$ metric in particular, had not been sufficiently tested, Witness Wintermantel stated that SERVM, the resource adequacy and production cost model used in the *Ancillary Service Study*, had been in use for decades, and that the $LOLE_{FLEX}$ metric had been used multiple times since 2015.[38] But Witness Wintermantel

[33] Tr. Vol. 5, p. 234, ll. 6-16.
[34] Tr. Vol. 6, p. 37, ll. 11-17.
[35] *Id.* at p. 20, l. 15-18.
[36] *Id.* at p. 38, ll. 2- 19.
[37] Tr. Vol. 4, p. 174, l. 19 – p. 175, l. 3.
[38] *Id.* at p. 204, l. 1 – p. 205, l. 17.

did not provide any examples of the methodology used in the *Ancillary Service Study* or the $\text{LOLE}_{\text{FLEX}}$ metric being used to calculate a renewable energy integration charge. In defending the model's credentials, Witness Wintermantel stated that the *Ancillary Service Study* had been sufficiently tested because "Duke employees who have years and years of experience had their hands in this model."[39]

Modeling DEC and DEP as Physical and Economic Islands

The *Ancillary Service Study* models DEP and DEC as physical and economic islands.[40] In initial comments, SACE critiqued the *Ancillary Service Study* for relying on the assumption that DEC and DEP are physical load islands.[41] NCSEA critiqued the *Ancillary Service Study* for failing to consider the reductions in ancillary service costs that would come from operating and modeling DEC and DEP as part of a reserve-sharing group of Energy Imbalance Market ("EIM").[42] The Public Staff also expressed concern regarding the *Ancillary Service Study's* modeling of DEC and DEP as load islands with no ability to rely on each other or on the larger Eastern Interconnection to meet intra-hour load variation.[43]

In reply comments, Duke Energy responded to SACE, NCSEA, and the Public Staff's critiques of the *Ancillary Service Study*'s "islanding" assumption, asserting that the Companies could not rely on external market assistance from other Balancing Authorities, VACAR RSG members, or transfers of non-firm energy under the DEC DEP Joint

[39] *Id.* at p. 2017, ll. 3-4.
[40] *Ancillary Service Study*, p. 13.
[41] *SACE Initial Comments*, Attachment A, p. 2.
[42] *NCSEA's Initial Comments*, pp. 36-37.
[43] *Public Staff's Initial Comments*, p. 36.

Dispatch Agreement ("JDA") in order to meet regulation reserve requirements on a real-time, intra-hour basis.[44] Duke Energy stated that if DEC and DEP were modelled as a combined BA, it would only reduce the proposed SISC by approximately 15%.[45]

In his direct testimony, Witness Wintermantel defended the *Ancillary Service Study's* islanding assumption on the basis that it would be "inappropriate for the Companies to assume that they are able to rely on surrounding neighbors."[46] Witness Wintermantel also testified that modeling DEC and DEP as a single BA would decrease the proposed SISC from $1.10/MWh to $0.94/MWh in DEC and from $2.39/MWh to $2.03/MWh in DEP.[47]

In his direct testimony, Witness Kirby explained that his critique of the *Ancillary Service Study*'s islanding assumption is not that utilities should be allowed to "lean on" their neighbors and shirk balancing responsibilities, but that modeling DEC and DEP as physical islands that will experience a load shedding event or blackout if they are unable to meet ramping requirements during a single 5-minute period is unrealistic given that they are, in reality, interconnected utilities for whom conformance to NERC reliability standard is sufficient to maintain system reliability.[48]

In his rebuttal testimony, Witness Wintermantel acknowledged that there are intra-hour benefits of participating in an interconnected system.[49] Witness Wintermantel characterized Witness Kirby's testimony as suggesting that neighboring Balancing Areas

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[44] *Duke Reply Comments*, p. 88.
[45] *Id.* at p. 93.
[46] Tr. Vol. 4, p. 74, ll. 12-16.
[47] *Id.* at p. 75, ll. 12-15.
[48] Tr. Vol. 5, p. 187, l. 4 – p. 191, l. 10.
[49] Tr. Vol. 4, p. 99, ll. 16-17.

should bear the cost of Duke's integration of solar.[50]

At the hearing, Witness Kirby clarified his critique of the "islanding" assumption in the *Ancillary Service Study*, explaining that a physically islanded utility must at all times have sufficient generation to match load, so ramp rate is a concern; but an interconnected utility, like DEC and DEP, will suffer no consequences for being short on ramping ability for five minutes.[51] Therefore, Witness Kirby explained, the consequence of modeling DEC and DEP as physical islands in the *Ancillary Service Study* is that the Study predicts a much higher level of reserves in order to meet a five-minute ramping requirement that does not exist for interconnected facilities.[52] As Witness Kirby stated, when a utility takes advantage of the value interconnection creates it does not burden or lean on its neighboring balancing areas—rather, everyone benefits.[53] Witness Kirby concluded that allowing Duke Energy to recover regulation reserve costs from QFs based on calculations of what would be required for physically islanded operations is unreasonable, since DEC and DEP do not operate as physical islands.[54]

Scaling of Intra-Hour Solar Variability

In initial comments, SACE critiqued the *Ancillary Service Study*'s assumption that intra-hour solar variability scales linearly, and asserted that reliance on this assumption resulted in intra-hour solar variability being overstated and the SISC being inflated.[55] SACE asserted that the relative intra-hour variability of an aggregation of solar plants

[50] *Id.* at p. 99, ll. 18-21.
[51] Tr. Vol. 5, p. 267, ll. 3-16.
[52] *Id.* at p. 266, l. 21 – p. 268, l. 19.
[53] *Id.* at p. 190, l. 1 – p. 191, l. 7.
[54] *Id.* at p. 191, ll. 8-10.
[55] *SACE Initial Comments*, p. 5; *id.* at Attachment A, pp. 11-12.

declines as the aggregation grows and that when analyzed, Duke Energy's historical data showed a decline in relative variability.[56] Therefore, SACE recommended that aggregation benefits should be accounted for in Study's intra-hour solar variability assumptions.[57] SACE recommended that intra-hour variability should be reduced for each solar penetration scenario in the *Ancillary Service Study*. For the Existing + Transition scenario, Witness Kirby recommended a 39% reduction (to 61%).[58]

In reply comments, Duke Energy stated that Duke Energy had analyzed the actual historical volatility data and calculated a 13% discount for DEC and 17% discount for DEP based on aggregation benefits.[59] The Companies criticized Witness Kirby's recommendation that the intra-hour solar volatility should be reduced to 61% for the Existing + Transition penetration scenario, stating that the formula Witness Kirby used was "subjective."[60] The Companies emphasized that they did not incorporate the 13% and 17% discounts they calculated in the proposed SISC because "these projections are not guaranteed to materialize."[61]

In his direct testimony, Witness Kirby explained that the short-term variability figures proposed in SACE's initial comments were based on the well-supported assumption that solar plant short-term variability is uncorrelated.[62] He explained that the formula SACE relied on to conclude that intra-hour solar volatility should be reduced to

56 *SACE Initial Comments*, Attachment A, p. 12.
57 *Id.* at p. 21.
58 *Id.* at p. 22.
59 *Duke Reply Comments*, p. 107.
60 *Id.* at p. 106.
61 *Id.* at p. 108.
62 Kirby Direct, p. 31.

61% for the Existing + Transition scenario was not "subjective" but was the standard root mean square statistical formula for combining the variability of uncorrelated entities.[63] Witness Kirby explained that it is well-documented in scientific literature that short-term variability of geographically dispersed solar plants is largely uncorrelated, and that therefore employing the formula for combining the variability of uncorrelated entities to determine intra-hour solar volatility was reasonable.[64] In other words, Duke Energy's assumption that solar variability scales linearly substantially overestimates the amount of intra-hour solar variability that should be expected as solar penetration increases.

At the hearing, Witness Wintermantel was asked why he did not include even the smaller 13% and 17% discount in solar variability that Duke Energy calculated for DEC and DEP respectively. Witness Wintermantel responded that "the Company has chosen" not to include those diversity benefits.[65] Witness Wintermantel also admitted that he is "not an expert" on the issue of calculating short-term solar variability.[66]

Accuracy of *Ancillary Service Study*'s Predictions

At the hearing, Witness Wintermantel admitted that Astrapé had not compared the *Ancillary Service Study*'s predictions to actual historical operating reserves for any year but 2015, which was compared to the baseline "no solar" scenario.[67] Witness Wintermantel also stated that he had no plans to test the *Ancillary Service Study*'s predictions against actual historical performance to see how well it matches up to actual experience.[68]

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[63] *Id.* at p. 32.
[64] Tr. Vol. 5, p. 194, l. 14 – p. 199, ll. 13.
[65] Tr. Vol. 4, p. 181, ll.19-22; *see id.* at p. 182, l. 21 – p. 183, l. 3.
[66] Tr. Vol. 6, p. 23, ll. 4-8.
[67] Tr. Vol. 4 p. 119, l. 10 – p. 120, l. 2.
[68] *Id.* at p. 2013, ll. 21 – p. 204, l. 2.

The Commission requested that Duke Energy provide the actual historical operating reserve data from 2014 through the present so that the *Ancillary Service Study* could be "rerun" to compare the *Study's* predictions for each year against reality.[69] The Commission specified that Duke Energy should provide not only aggregate historical reserves, but also more granular categories, including regulating reserves, load following reserves, and contingent reserves.[70] Witness Kirby agreed with the Commissioners that if the *Ancillary Service Study*'s predictions for the years 2014, 2015, 2016, 2017, and 2018 yielded results that conform to historic operating reserves, this would give him more confidence in the model.[71]

Following the hearing, Duke Energy filed Late Filed Exhibit 2, which provided aggregate historical reserves for the years 2015, 2016, 2017 and 2018.[72] Late Filed Exhibit 2 did not include the more granular categories of reserves that the Commission requested. Late Filed Exhibit 2 also did not "rerun" the *Ancillary Service Study*'s model for each of these years. Instead, it compared the aggregate historical reserves for the years 2015-2018 to the *Ancillary Service Study*'s 2020 No-Solar scenario and 2020 Existing + Transition Solar scenarios. Late Filed Exhibit 2 illustrated that Duke Energy's actual historical operating reserves have not increased exponentially as solar penetration has increased. Late

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[69] *Id.* at pp. 223-24; Vol. 5, pp. 291-92; Tr. Vol. 7, p. 107; *see also* Tr. Vol. 6, p. 45, ll. 3 – p. 46, l. 3. ("How difficult would it be to do that for the 2016, 2017, and 2018, to . . . run your model, hold it to the 0.1 . . . LOLE FLEX result, see what reserves the model spits out, and then compare to the actuals?" "I can go pull already existing results, kind of what the operating reserves, the model, say total for '15, '17, '18. That's just kind of imbedded in the... results.").
[70] Tr. Vol. 5, p. 291, l. 5 – p. 292, l. 8.
[71] *Id.* at p. 297, l. 6 – p. 299, l. 9.
[72] Duke Energy, Late Filed Exhibit 2, pp. 1-3.

Filed Exhibit 2 also demonstrated that contrary to Witness Wintermantel's testimony,[73] the *Ancillary Service Study*'s "base case" does not align with the 2015 Actual historical reserves.[74]

Comparison to Idaho Power Study

In initial comments, SACE cited a 2016 Solar Integration Study Report by Idaho Power ("Idaho Power Study") as a feasible and realistic approach to calculating a solar integration charge.[75] Specifically, SACE highlighted the reliability metric used in the Idaho Power Study, which allowed a total of *90 hours per year* of deviations, as opposed to the 0.1 $LOLE_{FLEX}$ metric used by the *Ancillary Service Study*, which allows *one single five-minute deviation in ten years*.[76]

In reply comments, the Companies stated that the Idaho Solar Integration Study predicted similar levels of incremental operating reserves required at 800 MW and 1600 MW of solar penetration as the Ancillary Services Study.[77] In his direct testimony, Witness Wintermantel testified that the Idaho Power Study and the *Ancillary Service Study* produced similar results at similar solar penetration levels.[78]

In his Direct Testimony, Witness Kirby responded to Witness Wintermantel's claim that the Idaho Power Study and the *Ancillary Service Study* produce similar results. Witness Kirby explained that the Idaho Power BA is far smaller than DEC and DEP (peak load is 3,400 MW for Idaho Power and 20,600 MW and 14,000 MW for DEC and DEP

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[73] *See* Tr. Vol. 6, p. 38, ll. 2- 19.
[74] Duke Energy, Late Filed Exhibit 2, pp. 1-2.
[75] *SACE Initial Comments*, Attachment A, p. 10.
[76] *Id.* at pp. 10-11.
[77] *Duke Reply Comments*, p. 99.
[78] Tr. Vol. 4, p. 78, ll. 1-11.

respectively) and experiences far higher levels of renewable penetration than DEC and DEP (67% for Idaho Power and 5% to 33% for the solar penetration scenarios modelled in the *Ancillary Service Study*).[79] As a result, Witness Kirby concluded, the reserve requirement and integration costs calculated in the *Ancillary Service Study* far exceed those calculated in the Idaho Power Study when analyzed based on renewables penetration by percentage.[80] Furthermore, Witness Kirby explained, unlike the Idaho Power Study, the *Ancillary Service Study* predicts exponentially increasing integration costs as solar penetration increases.[81]

In his rebuttal testimony, Witness Wintermantel continued to maintain that the results of the *Ancillary Service Study* and Idaho Power Study are comparable, stating that "solar volatility is simply a function of the nominal size of the solar fleet and not at all related to the size of system load" and that therefore comparing incremental operating reserves relative to renewable penetration as a percentage of total load, as Witness Kirby did, was inappropriate.[82]

At the hearing, Witness Wintermantel admitted that the size of a Balancing Authority may have an impact on the amount of operating reserves that must be added to as solar penetration increases.[83] Public Staff Witnesses Jeff Thomas and Dustin Metz also testified that many factors other than the total amount of MW of solar in a Balancing Authority, including the Balancing Authority's size, impact the amount of load following

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[79] Tr. Vol. 5, p. 201, l. 9 – p. 203, l. 8.
[80] *Id.*
[81] *Id.* at p. 201, ll. 15-18.
[82] Tr. Vol. 4, p. 96, l. 12 – p, 97, l. 6.
[83] *Id.* at p. 151, ll. 15-18.

reserves necessary to adjust for increasing solar penetration.[84]

NCSEA Witness Beach also provided testimony regarding the Idaho Power Study. Witness Beach explained that both Idaho Power and PacifiCorp have conducted multiple renewable integration studies over time, and that for both utilities, integration cost estimates have declined over time, even as renewable penetration increased.[85] Witness Beach noted that the most recent Idaho Power and PacifiCorp integration studies, which calculated the lowest renewable integration charges, included review by a technical review committee of outside experts from institutions such as the National Renewable Energy Laboratory ("NREL"), the Western Renewable Energy Generation Information System ("WREGIS"), and the Utility Wind Interest Group ("UWIG").[86] Witness Beach noted than Duke Energy's *Ancillary Service Study* was not subject to independent technical review.[87]

<u>Consideration of Costs and Benefits</u>

In its initial comments, NCSEA argued that the *Ancillary Service Study* and Duke Energy's proposed SISC should be rejected for failing to consider both the costs and benefits of solar QFs in conformance with the Commission's Sub 140 Order. In that Order, the Commission determined that "integration of solar resources into a utility's generation mix results in both costs and benefits," and inclusion of solar integration costs and benefits in avoided cost calculations would only be appropriate "when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained."[88] Duke Energy proposes to impose the SISC to

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[84] Tr. Vol. 6, p. 444, l. 16 – p. 446, l. 21.
[85] Tr. Vol. 5, p. 121, l. 4 – p. 122, l. 4.
[86] *Id.* at p. 122, l. 8 – p. 123, l. 2.
[87] *Id.* at p. 123, ll. 2-3.
[88] *NCSEA's Initial Comments*, p. 32 (*quoting Sub 140 Phase I Order*, p. 60).

recover integration costs from solar QFs without also quantifying and including integration benefits, and therefore NCSEA urged that the SISC should be rejected as inconsistent with the Commission's prior directive.

NCSEA characterized Duke Energy's proposed SISC as a "punitive charge" on QFs rather than a "rate based on the characteristics of QF-supplied power."[89] In an expert report attached to NCSEA's initial comments, Witness Beach explained that at least two benefits associated with integration solar energy should have been considered in the *Ancillary Service Study*: lower overall wholesale market prices due to integration of zero-variable cost renewables, and avoided transmission and distribution capacity cost ("T&D") savings due to distributed solar.[90] Witness Beach asserted that the Companies have already quantified their avoided T&D capacity costs as part of their efforts to assess the benefits of energy efficiency programs, and explained how these benefits could be incorporated into avoided cost rates.[91]

In reply comments, Duke Energy argued that T&D savings are not "known and measurable" and are too "speculative" to be considered in the calculation of avoided costs under PURPA.[92] Duke Energy also critiqued Witness Beach's use of the T&D benefits calculated for energy efficiency programs in the avoided cost context, arguing that this is not an "apples-to-apples" comparison.[93] In his testimony, Duke Witness Snider characterized the benefits Witness Beach identified as "speculative and not real costs."[94]

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[89] *Id.* at p. 35.
[90] Beach Affidavit, pp. 6-7.
[91] *NCSEA's Initial Comments*, pp. 21-24.
[92] *Duke Reply Comments*, pp. 126-128.
[93] *Id.* at pp. 128-29.
[94] Tr. Vol. 2, p. 141, ll. 7-8.

In his testimony, Witness Beach explained that multiple studies have quantified the reduction in wholesale market prices due to integration of renewables.[95] Specifically, Witness Beach testified that the current penetration of renewables in DEC and DEP could easily account for a 4% reduction in energy market prices in North Carolina, which would substantially offset the proposed SISC.[96]

At the hearing, Witness Snider testified that the Companies had not quantified the T&D costs or benefits associated with distributed solar.[97] Witness Snider admitted that the Companies had not commissioned any studies attempting to quantify T&D benefits.[98]

Connection to Resource Adequacy Studies

The *Ancillary Service Study* relies on many of the same assumptions regarding DEC and DEP's load as Astrapé's 2016 Resource Adequacy Studies ("RA Studies").[99] In initial comments, the Public Staff noted its concern that the *Ancillary Service Study* relied on the same problematic resource adequacy modeling assumptions discussed in the Public Staff and Duke's Joint Report in the 2017 IRP proceeding.[100] SACE discussed these flaws—overstated loss of load risk at extreme cold temperatures; unreasonable demand response assumptions; overstated economic load forecast uncertainty; and inaccurate assumptions regarding operating reserves during brief load spikes on cold winter mornings—at length in its initial comments and in Witness Wilson's direct testimony.[101]

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[95] Tr. Vol. 5, p. 115, l. 12 – p. 116, l. 3.
[96] *Id.*
[97] Tr. Vol. 3, p. 19, ll. 7-17.
[98] *Id.* at p. 20, l. 17 – p. 21, l. 8.
[99] *Ancillary Service Study*, p. 14.
[100] *Public Staff's Initial Comments*, p. 36; *Joint Report of the Public Staff, Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC*, pp. 9-17, Docket No. E-100, Sub 147 (April 2, 2018).
[101] *SACE Initial Comments*, p. 12; Tr. Vol. 5, pp. 333-41.

Impact on H.B. 589 Programs

The parties to this proceeding agreed that the proposed SISC could have implications beyond PURPA solar QFs, and could also impact solar facilities participating in legislatively mandated H.B. 589 programs. The Competitive Procurement of Renewable Energy ("CPRE"), Green Source Advantage ("GSA"), and Community Solar programs are all currently tied to the avoided cost rate established in this proceeding.[102] Duke Energy confirmed its perspective that the proposals in this proceeding with impact the CPRE, GSA, and Community Solar programs.[103] However, there is significant disagreement regarding *whether* and *how* the proposed SISC would or should impact these programs. Duke Witness Wheeler stated that the SISC would apply to CPRE Tranche 2 if approved by the Commission in this proceeding.[104] Public Staff Witness Thomas testified that the Public Staff did not know how the SISC would be implemented in CPRE.[105] Intervenors expressed concern that (i) it is inappropriate to make decisions about the applicability of an SISC to other programs in this docket; (ii) applying an SISC to CPRE Tranche 2 and GSA on the eve of the opening of those programs would be highly disruptive, especially since the details of how an SISC would be incorporated into those programs, or how the SISC can be mitigated, have not been worked out; (iii) application of an SISC to CPRE could harm rather than benefit ratepayers; (iv) application of an SISC to GSA should not be considered without simultaneously revisiting the bill credit; and (v) if the SISC were to be applied to CPRE, reducing the CPRE bid cap, bids at the previous Tranche 1 threshold could be

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[102] Tr. Vol. 3, p. 142, ll. 12-19.
[103] Tr. Vol. 2, p. 349, l. 7 – p. 350, l. 10; *id.* at p. 350, l. 15 – p. 351, ll. 21.
[104] *Id.* at p. 290, ll.18-24.
[105] Tr. Vol. 6, p. 428, ll. 18-20.

rendered unviable if the SISC were to be applied to CPRE, reducing the CPRE bid cap, bids at the previous Tranche 1 threshold could be rendered unviable.[106]

SISC Stipulation

On May 21, 2019 Duke Energy and the Public Staff entered into a *Stipulation of Partial Settlement Regarding Solar Integration Services Charge* ("*SISC Stipulation*"). The *SISC Stipulation* provided that the *Ancillary Service Study*'s "data, methodology, results and conclusions are reasonable for the purpose of quantifying . . . the [SISC]."[107] The *SISC Stipulation* provided that the SISC would only be applied prospectively, and would not be applied to solar generators who can demonstrate, "as reasonably determined by the Companies," and contract to operate, in a manner that "material reduces or eliminates the need for additional ancillary service requirements."[108] The *SISC Stipulation* also provided that the SISC, currently set at $1.10/MWh for DEC and $2.39 MWh for DEP, would be subject to a "refresh" every two years that could not exceed a cap of $3.22/MWh for DEC and $6.70/MWh for DEP.[109]

SACE and NCSEA urged the Commission to reject the *SISC Stipulation*. NCSEA Witness Beach testified that the SISC failed to consider how the benefits associated with solar QFs, such as transmission and distribution savings, could offset integration costs; and failed to address Intervenors concerns regarding the *Ancillary Service Study*'s modeling of the DEC and DEP systems as islands.[110] Witness Beach also testified that the cap set by

[106] Tr. Vol. 2, p. 383, l. 20 – p. 384, l. 7; p. 302, ll. 4-14.
[107] *SISC Stipulation* at III.A.
[108] *Id.* at II.A.
[109] *Id.* at IV.C, VI.
[110] Tr. Vol. 5, p. 127, ll. 5-10.

the Stipulation was far too high, and well above the solar integration charges adopted in other jurisdictions.[111] Witness Kirby agreed that the cap provided in the *SISC Stipulation* was inappropriately high.[112] Public Staff Witness Jeff Thomas testified in support of the *SISC Stipulation*. Witness Thomas testified that during private meetings between the Public Staff, the Companies, and Astrapé, the Public Staff became convinced that the methodology used in the *Ancillary Service Study* was reasonable.[113] Witness Thomas further testified that Astrapé and Duke Energy conducted sensitivity testing using "post-processing" techniques that demonstrated that the islanding assumptions and concerns about the $LOLE_{FLEX}$ metric raised by Intervenors were not as significant as the Public Staff initially believed.[114] Both Witness Wintermantel and Witness Thomas stated that the reductions in the SISC achieved by modeling DEC and DEP as a single BA or by relaxing the $LOLE_{FLEX}$ metric were not sufficiently large to merit changing the methodology.[115]

When asked about the sensitivity analysis conducted on various study assumptions with the Public Staff, Witness Wintermantel admitted that no information regarding the "post-processing techniques" discussed by Witness Thomas had been introduced into the record.[116] Witness Wintermantel confirmed that he did not "rerun" the *Ancillary Service Study* with changed assumptions, but merely "attempt[ed] to interpolate" in order to estimate the impact of changing certain assumptions.[117]

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[111] *Id.* at p. 127, ll. 15-20.
[112] *Id.* at p. 208 ll. 4-13.
[113] Tr. Vol. 6, p. 361, ll. 5-8.
[114] *Id.* at 362, l. 9 – p. 363, l. 4.
[115] Tr. Vol. 4, p. 166, l. 10 – p. 167, l. 5.
[116] *Id.* at p. 174, l. 19 – p. 175, l. 3.
[117] *Id.* at p. 173, l. 21 – p. 174, l. 18.

Avoidance of the SISC by Innovative Solar QFs

The *SISC Stipulation* provided that the SISC would not be applied to solar generators who can demonstrate, "as reasonably determined by the Companies," and contract to operate, in a manner that "material reduces or eliminates the need for additional ancillary service requirements."[118] The Stipulation further provided that a "solar generator seeking to reduce or eliminate the applicability of the Integration Services Charge shall contractually agree to construct and operate its solar generating facility and co-located energy storage to meet design specifications and operational requirements, as reasonably determined by Duke . . ."[119]

There is general agreement among the parties that a solar QF with battery storage can be operated to "smooth" its delivered energy output by charging the battery when solar output quickly spikes and by discharging the battery when solar output quickly drops.[120] Since, as Witness Snider explained, intra-hour volatility is the main driver for costs quantified by the SISC, a solar QF operating to smooth energy output should not be subject to the SISC.[121] However, Witness Snider testified, the "mere existence of a battery does not guarantee that you're going to have less intermittency"—the battery needs to be operating in a particular way to have this effect.[122] Therefore, Witness Snider explained, the *SISC Stipulation* requires that in order to avoid the SISC, a QF would be required to demonstrate that it is capable of operating in such a manner to the Companies' satisfaction,

118 *SISC Stipulation* at II.A; Tr. Vol. 2, p. 319, ll. 2-5.
119 *SISC Stipulation* at II.A.
120 Tr. Vol. 2, p. 152, ll. 7-10.
121 *Id.* at p. 151, l. 17 0 p. 153, l. 7.
122 *Id.* at p. 355, ll. 5-7.

and then contract to do so.[123]

NCSEA Witness Beach testified that the language included in the Stipulation is insufficiently detailed to allow a QF to avoid the SISC.[124] Witness Snider acknowledged that the Companies have not yet finalized energy storage protocols or proposed a fully dispatchable PPA for CPRE Tranche 2, so potential Tranche 2 participations do not yet know what would be required for them to avoid the proposed SISC and how to factor those requirements into their bids.[125] Witness Snider also admitted that because none of these details have been finalized, CPRE Tranche 2 participants likely would not have the option of avoided the propose SISC.[126]

The *SISC Stipulation* stated that if a solar generator "can demonstrate that the facility is capable of operating, and shall contractually agree to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements (as reasonably determined by the Companies), through inclusion of energy storage devices, dispatchable contracts, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generators ('controlled solar generators')."[127] Pursuant to the *SISC Stipulation*, this determination would be subject to the Companies' discretion, and the *SISC Stipulation* does not describe what would be required for solar generators to be considered "controlled solar generators."

As parties have described throughout this proceeding, coupling solar facilities with battery storage can provide a variety of tools to increase operational efficiencies, maximize

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[123] *Id.* at p. 354, l. 20 – p. 355, l. 21.
[124] Tr. Vol. 5, p. 127, l. 21 – p. 128, l. 7.
[125] Tr. Vol. 3, p. 154, l. 2 – p. 158, l. 23.
[126] *Id.* at p. 157, ll. 20-23.
[127] *Id.* at p. 5.

the value of renewable generation, and save ratepayers money. With respect to the specific provision in the *SISC Stipulation* before the Commission in this proceeding, however, solar QFs will have no way of knowing what would be required of them to be considered a "controlled solar generator." Duke Witness Snider acknowledged this during the evidentiary hearing and stated that Duke considered it "more appropriate that we're addressing the storage protocol as part of [H.B.] 589, and that we would take this into consideration" in the context of H.B. 589 programs rather than during the avoided cost proceeding.[128]

DISCUSSION AND CONCLUSIONS

The Commission reaffirms its finding in the *Sub 140 Phase I Order* that "integration of solar resources into a utility's generation mix results in both costs and benefits."[129] The Commission further reaffirms its directive that inclusion of solar integration costs and benefits in avoided cost calculations would only be appropriate "when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained."[130] The Commission finds persuasive NCSEA Witness Beach's testimony that the *Ancillary Service Study* fails to consider quantifiable benefits associated with renewable integration, including avoided Transmission and Distribution costs and lower overall wholesale market prices due to integration of zero-variable cost renewables. The Commission finds informative Witness Snider's testimony that Duke Energy has not sought to commission a study quantifying

[128] Tr. Vol. 3, p. 33.
[129] *Sub 140 Phase I Order*, p. 60.
[130] *Id.* at 61.

avoided T&D costs. The Commission concludes that by failing to consider the benefits along with the costs of solar integration, the Companies have not complied with the Commission's *Sub 148 Order* allowing utilities to "propose schedules specific to QFs that provide intermittent non-dispatchable power, if the Utilities' cost data demonstrated marked differences in the value of the energy and capacity provided by these QFs." The Commission therefore determines that the SISC is premature at this time, because the Companies have not simultaneously studied and quantified the benefits of integrating solar power onto the system.

The Commission determines that the SISC is also premature at this time due to the potential ramifications for other renewable energy programs, in particular the CPRE, GSA, and Community Solar programs. Although Duke Energy asserts that the SISC would apply to these other programs, particularly the CPRE program, it is unclear how the SISC would be applied and how it would impact the success of these programs and the state's renewable energy procurement goals. The Commission agrees that the proposed SISC would impact the CPRE, GSA, and Community Solar programs created by H.B. 589. The Commission also acknowledges the imminent commencement of CPRE Tranche 2, and notes that the proposed SISC has not been discussed in the context of CPRE Tranche 2. The Commission also notes Witness Snider's statement that participants in CPRE Tranche 2 currently do not have enough information to determine whether they will be able to avoid the proposed SISC by conforming to a yet-to-be-proposed fully dispatchable PPA. In the absence of clarity regarding how the SISC would be implemented, how it would impact participation in these programs, and how these impacts would affect ratepayers, the Commission does not believe it is appropriate to approve the proposed SISC at this time.

While the Commission need not address additional aspects of the SISC at this time, it nevertheless provides guidance below regarding the details of the underlying *Ancillary Services Study* to inform future integration cost and benefit proposals.

The Commission recognizes that the *Ancillary Service Study* seeks to quantify the costs of solar integration by determining the amount of additional load-following reserves that are necessary in order to keep the system's operational reliability constant as solar penetration increases. However, the Commission finds persuasive SACE Witness Kirby's testimony the *Ancillary Service Study* contains several methodological flaws that compromise the Study's reliability. The Commission finds inappropriate the *Ancillary Service Study*'s reliance on the $LOLE_{FLEX}$ metric, the assumption that DEC and DEP are physical islands, and the assumption that intra-hour solar volatility scales exponentially.

The Commission observes that the *Ancillary Service Study* applies long-term resource adequacy principles to attempt to quantify real-time operational reliability. Compounding the intervenor concerns regarding the merits of using this methodology for approximating NERC compliance, this particular novel approach has not been peer-reviewed or subject to a Technical Review Committee. The Commission finds the lack of independent, third-party analysis of the *Ancillary Service Study* to be problematic in light of the numerous critiques raised by Intervenors and evidence that integration studies in other jurisdictions, including the 2016 Idaho Power Study and 2017 PacifiCorp Study, were subject to Technical Review Committees. The Commission also notes that Duke Energy was given an opportunity to validate the *Ancillary Service Study*'s predictions by comparing the Study's predictions to actual historical operating reserves data. But Duke Energy only partially complied with the Commission's request, and did not provide sufficient data to justify its claims that increasing solar penetration leads to exponentially increasing integration costs. The historical data Duke Energy did provide demonstrates that as solar penetration has increased, operating reserves have remained relatively stable.

The Commission further recognizes that some of the resource adequacy assumptions underlying the *Ancillary Service Study* are subject to the same critiques Intervenors have raised in regards to the 2016 RA Studies in this proceeding and in concurrent IRP proceedings. The Commission's 2016 IRP Order directed Duke to revisit and refine some of the resource adequacy assumptions, including load forecasting methodology and for reserve margin calculations, raised by Witness Wilson.[131] The Commission's recently issued Order Accepting Integrated Resource Plans And REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses ("2018 IRP Order") specifically declined to accept "some of the underlying assumptions upon which DEC's and DEP's IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020."[132] The Commission's 2018 IRP Order also scheduled an oral argument for January 8, 2020, to further consider Witness Wilson's concerns regarding Duke Energy's load forecasts and reserve margins.[133] In light of these unresolved concerns regarding resource adequacy assumptions underlying the *Ancillary Service Study*, the Commission reiterates that it is premature to approve the proposed SISC at this time.

The *SISC Stipulation* states that "[t]he Stipulating Parties agree that the Astrapé

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[131] *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans* ("2016 IRP Order"), Docket No. E-100, Sub 147 (June 27, 2017).
[132] *Order Accepting Integrated Resource Plans and REPs Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*, p. 7, Docket No. E-100, Sub 157 (August 27, 2019).
[133] *Id.* at p. 89.

Study's data, methodology, results, and conclusions are reasonable for purposes of quantifying the Companies' 'average' and 'incremental' ancillary services costs attributable to integrating solar generation, as well as for purposes of calculating the Companies' Integration Services Charge."[134] As described above, the Astrapé Study's data, methodology, results, and conclusions are not reasonable.

The Commission notes that all parties agree that solar QF with battery storage can use their battery to smooth the profile or shift the timing of QF energy production. The Commission recognizes the agreement between the parties that when a battery is used to smooth the profile of a solar QF's energy production, it can reduce solar volatility and potentially mitigate or eliminate any need for additional ancillary service requirements. The Commission acknowledges that a key provision of the SISC Settlement, the ability of a solar QF to avoid the integration charge if it is a "controlled solar generator" has not been adequately detailed, and solar QFs—as well as the Commission—do not know what would be required for a solar QF to avoid the SISC.

The *SISC Stipulation* lacks details as to whether and to what extent the SISC would apply to H.B. 589 programs, and Duke and the Public Staff have demonstrated that they do not agree as to whether or how the charge would be applied to these programs. With respect to the specific provision in the *SISC Stipulation* before the Commission in this proceeding, however, solar QFs have no way of knowing what would be required of them to be considered a "controlled solar generator." Duke witness Snider acknowledged this during the evidentiary hearing and stated that Duke considered it "more appropriate that

[134] *Id.*, p. 6.

we're addressing the storage protocol as part of [H.B.] 589, and that we would take this into consideration" in the context of H.B. 589 programs rather than during the avoided cost proceeding.[135]

The evidence in this proceeding has demonstrated that renewable energy integration charges often decrease as utilities adapt and learn to better manage the integration of renewables.[136] Despite this, the cap included in the *SISC Stipulation* is based on the estimated "incremental" rate, which incorporates a wide range of assumptions called into question in this proceeding, and would directly impact the financial assumptions that solar generators would have to make when financing their projects or when participating in H.B. 589 programs. Duke Witness Snider agreed during cross-examination that QFs bidding into the CPRE program would have to assume the full cap would apply during the contract, stating "if I was evaluating it and was a bidder, I would say it starts with my base case being the charge as implemented and my tail risk is the cap."[137] Public Staff Witness Thomas stated that he could not "speak to the ability of QFs to . . . obtain financing with or without the cap."[138]

The Commission also notes that a major issue – how solar plus storage QFs would be exempted from the SISC – is unaddressed in the *SISC Stipulation*. Despite Duke Energy's assurances that it will work with solar QFs and other stakeholders in the future to establish a storage protocol and will negotiate PPAs in good faith to incorporate the

[135] Tr. Vol. 3, p. 33.
[136] NCSEA Witness Beach's testimony shows that the California Independent System Operator ("CAISO"), an operator for a state with a significantly higher amount of distributed solar and wind generation sources[136], did not see increased ancillary benefits costs "over a 13-year period in which the amount of wind and solar resources integrated by the CAISO has increased nine-fold." Tr. Vol. 5, p. 131.
[137] Tr. Vol. 3, p. 28.
[138] Tr. Vol. 6, p. 422.

protocol or other means by which a solar facility can avoid the SISC, Duke will hold tremendous leverage during any such negotiations. The Commission cannot adopt a stipulation that leaves a major provision unknown and subject to future negotiation. As discussed above, because the term "controlled solar generator" has not been adequately defined or described, the Commission must reject the *SISC Stipulation*.

Based upon the foregoing and the entire record herein, the Commission concludes that Duke Energy's proposal to impose a SISC on QFs should not be adopted at this time. The Commission encourages Duke Energy to quantify and incorporate benefits in addition to costs in future integration studies; to fully consider the implications of proposed charges or credits to other renewable programs including CPRE, GSA, and Community Solar programs; and to have Astrapé seek out independent peer review or a TRC in developing any future studies that rely on the $LOLE_{FLEX}$ metric in this context. The Commission finds that there is insufficient evidence in the current record before it to support Duke Energy's assertion that the *Ancillary Service Study* accurately approximates the costs of integrating solar onto the DEC and DEP systems.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

SUMMARY OF THE EVIDENCE

In its initial filings, Dominion proposed a $1.78/MWh Solar Re-Dispatch Charge ("Re-Dispatch Charge").[139] Dominion characterized this charge as representing "the increase in system supply costs—specifically, re-dispatch costs—caused by . . .

[139] *Initial Statement and Exhibits of Dominion Energy North Carolina*, p. 12, Docket No. E-100, Sub 158 (November 1, 2019) ("*Dominion Initial Statement*").

intermittent non-dispatchable QFs."[140]

In its initial comments, and through an expert report authored by Witness Kirby, SACE expressed concern regarding several aspects of Dominion's methodology for determining the Re-Dispatch Charge. Specifically, SACE asserted that the methodology used inappropriate solar penetration levels; averaged re-dispatch costs of multiple solar penetration levels; and averaged multiple combinations of assumptions in unreasonable ways, resulting in an inflated Re-Dispatch Charge.[141] The Public Staff also expressed concern with the calculations for the Re-Dispatch Charge, particularly the weighting of cost categories and solar penetration scenarios.[142] NCSEA also critiqued the proposed Re-Dispatch Charge's methodology and asserted that the costs calculated by Dominion should be netted against the T&D benefits of distributed solar generation.[143] NCSEA calculated an alternative re-dispatch charge of $0.69/MWh.[144]

In its reply comments, Dominion agreed to recalculate the Re-Dispatch Charge with modified cost categories and solar penetration scenario weightings, and proposed a significantly reduced $0.78/MWh Re-Dispatch Charge.[145] Dominion argued that it had accounted for some benefits associated with distributed solar generation through other aspects of the avoided rates, including the hedge value adder.[146] Dominion also asserted that non-dispatchable QFs do not allow Dominion to avoid any T&D costs, and therefore

[140] *Id.* at pp. 12-13.
[141] *SACE Initial Comments*, p. 18; *id.* at Attachment C.
[142] *Public Staff's Initial Comments*, p. 45.
[143] Beach Affidavit, p. 18-20.
[144] *Id.* at 20.
[145] *Reply Comments of Dominion Energy North* Carolina, p. 25, Docket No. E-100, Sub 158, (March 27, 2019) ("*Dominion Reply Comments*").
[146] *Id.* at pp. 19-20.

it is inappropriate to consider avoided T&D costs as a benefit for offsetting the Re-Dispatch Charge[147] savings due to distributed solar.[148] Dominion Witness Petrie's direct testimony further explained the changes Dominion had made in calculating the revised Re-Dispatch Charge.[149]

In his direct testimony, Witness Kirby stated that Dominion's willingness to remove the 80 MW Scenario from its analysis and base its proposed Re-Dispatch Charge calculations on the "all costs" analysis alleviated the majority of this concerns regarding the calculation of the Charge.[150] However, Witness Kirby maintained that Dominion's failure to include analysis of the benefits of distributed solar remained problematic.[151]

At the hearing, Witness Petrie testified that Dominion had not commissioned a study to calculate avoided T&D costs, but stated that Dominion's intent was to eventually "weigh and quantify the costs and benefits" of solar generation.[152]

Witness Billingsley testified that Dominion only sought to apply the recalculated Re-Dispatch Charge prospectively.[153] Witness Billingsley also testified that there were some circumstances where it would be inappropriate to apply a Re-Dispatch to a QF with battery storage.[154] Witness Billingsley explained that if a battery is operated to "shift" energy—"charge in the morning and discharge in the evening to take advantage of the on-

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[147] *Id.* at pp. 20-21.
[148] Beach Affidavit, pp. 6-7.
[149] Tr. Vol. 5, p. 21, l. 17 – p. 22, l. 4.
[150] *Id.* at p. 209, l.4 – p. 210, l. 6.
[151] *Id.* at p. 209, ll. 1-3.
[152] *Id.* at p. 82, l. 17 – p. 83, l. 14.
[153] *Id.* at p. 91, l. 23 – p. 91, l. 16.
[154] *Id.* at p. 93, ll. 20-24.

peak/off-peak spread"—it will not reduce intermittency.[155] But if the battery is operated to "smooth" a QF's energy output, it could eliminate the intermittency that justifies the imposition of Dominion's proposed Re-Dispatch Charge.[156] Witness Billingsley also testified that Dominion was not prepared to offer any proposed operating protocols for storage that would allow a solar QF to be exempted from the Re-Dispatch Charge.[157]

DISCUSSION AND CONCLUSIONS

As stated above, the Commission reaffirms its finding in the *Sub 140 Phase I Order* that "integration of solar resources into a utility's generation mix results in both costs and benefits."[158] The Commission further reaffirms its directive that inclusion of solar integration costs and benefits in avoided cost calculations would only be appropriate "when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained."[159]

Dominion Witness Petrie admitted at the hearing that Dominion has not commissioned a study to calculate avoided T&D costs, but stated that Dominion's intent was to eventually "weigh and quantify the costs and benefits" of solar generation. Thus, the Commission concludes that the proposed Re-Dispatch charge is premature at this time and inconsistent with the Commission's prior order on this matter, requiring the quantification of both costs and benefits.

For consideration in future proceedings, the Commission recognizes and appreciates Dominion's willingness to recalculate the proposed Re-Dispatch Charge in

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[155] *Id.* at p. 93, ll. 3-24.
[156] *Id.*
[157] Tr. Vol. 5, p.95, ll. 3-24.
[158] *Sub 140 Phase I Order* at p. 60.
[159] *Id.* at 61.

accordance with recommendations from the Public Staff and other Intervenors. The Commission notes that the recalculated Re-Dispatch Charge of $0.78/MWh is a significant reduction from Dominion's original proposal, and is comparable to the $0.69/MWh charge calculated by NCSEA Witness Johnson.

The Commission also notes Witness Billingsley's testimony that it would be inappropriate to impose the Re-Dispatch Charge upon solar QFs with battery storage that operate to "smooth" a QF's output. Despite this acknowledgement, Dominion has not currently proposed a battery storage protocol or terms that would allow QFs operating in such a manner to avoid the proposed Re-Dispatch Charge. As such, if the Re-Dispatch Charge were to be approved, even QFs operating to smooth output in a manner that eliminates re-dispatch costs on the system would still be subject to the Re-Dispatch Charge. This lends further support to the Commission's conclusion that the Re-Dispatch charge is premature at this time.

Based upon the foregoing and the entire record herein, the Commission concludes that Dominion's proposal to impose a Re-Dispatch on QFs should not be adopted at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 9-15

<u>SUMMARY OF THE EVIDENCE</u>

In the Sub 148 proceeding, the Commission ordered the Companies to calculate their avoided capacity rates using seasonal allocation weightings of 80% winter and 20% summer.[160] In its initial filings in this proceeding, Duke Energy proposed a 100%/0%

[160] *Sub 148 Order*, Ordering Paragraph 5.

winter/summer capacity payment weighting for DEP and a 90%/10% weighting for DEC.[161] Duke Energy relies on the DEC and DEP Solar Capacity Value Study performed by Astrapé ("*Solar Capacity Value Study*") to justify its proposed seasonal capacity weighting. This seasonal capacity payment weighting is included in the Stipulation of Partial Settlement among DEC, DEP, and the Public Staff on April 18, 2019 (hereinafter "*Rate Design Stipulation*").[162]

In its initial comments and through an expert report authored by SACE Witness James Wilson, SACE critiqued the *Solar Capacity Value Study* and the seasonal capacity allocation it produces for relying on the same model and many of the same flawed assumptions used in Duke Energy's 2016 Resource Adequacy Studies.[163] SACE asserted that these flaws resulted in inaccurate and improper avoided capacity rates that caused solar QFs to be underpaid for their capacity contributions in the summer.[164] SACE pointed to four problematic assumptions in the RA Studies that tainted the *Solar Capacity Value Study's* accuracy.

First, SACE asserted that the RA studies significantly overstated the risk of very high loads under extreme cold primarily due to faulty assumptions regarding the relationship between extreme cold and load.[165] SACE stated that while the Companies assume that under extreme cold conditions DEC load will increase by 231 MW for each degree the temperature falls; Witness Wilson's analysis showed that the historical

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[161] *Duke Initial Statement*, p. 29.
[162] *Rate Design Stipulation* at IV.
[163] *SACE Initial Comments*, pp. 11-12.
[164] *Id.* at 12.
[165] *Id.* at Attachment B, pp. 6-13.

relationship was much weaker at extreme temperatures, likely reflecting that under extreme cold temperatures customers have already turned on all of their heating resources and many public facilities, such as schools and government buildings close, reducing loads.[166] Second, SACE asserted that the RA studies overstated winter resource adequacy risk by assuming that demand response will continue to be summer-focused even though the Companies have identified more resource adequacy risk in the winter.[167] Witness Wilson's report stated that if the Companies were to assume equal levels of demand response in winter and summer, most of the hours with load loss would be in the summer rather than winter.[168] Third, SACE asserted that the RA studies improperly layered greatly overstated "economic load forecast uncertainty" on top of the weather-related load distribution.[169] Fourth, SACE asserted that the studies used inaccurate assumptions regarding operating reserves during brief load spikes on extremely cold winter mornings.[170]

In its initial comments and through Witness Ben Johnson's affirmation, NCSEA also critiqued Duke Energy's demand-side response management ("DSM") assumptions.[171] NCSEA Witness Johnson's affidavit noted that, now that Duke is utilizing a winter peak for calculating avoided costs, it should reorient its DSM offerings to primarily focus on winter peaks.[172] NCSEA Witness Johnson further notes that, given that winter peaks are less frequent and of shorter duration than summer peaks, "a winter-

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[166] *Id.*
[167] *Id.* at pp. 19-20.
[168] *Id.* at pp. 19-20.
[169] *Id.* at pp. 14-19.
[170] *Id.* at pp. 6-7.
[171] *NCSEA's Initial Comments*, pp. 12-13.
[172] *Id.* at Attachment 1, p. 38 ("Johnson Affidavit").

oriented DSM program will be more attractive to more customers, yet it will be just as effective (or more effective) in meeting the shorter, less frequent peaks that occur during the winter season."[173] NCSEA Witness Johnson then recommended that the Commission reject the DSM assumptions used by DEC and DEP because they fail to minimize the cost or maximize the effectiveness of the DSM programs.[174]

In reply comments, Duke Energy explained that in its June 27, 2017 Order on the 2016 IRP Proceeding, the Commission concluded that the Companies' reserve margins in their 2017 IRPs were reasonable, but also directed the Companies to work with the Public Staff to address outstanding concerns regarding the RA Studies raised by the Public Staff and SACE Witness Wilson.[175] Duke Energy noted that the Companies and Public Staff were directed to file a Joint Report on April 2, 2018 to the Commission regarding these issues.[176] Duke Energy also acknowledged that the Companies and the Public Staff did not ultimately reach agreements on all the issues in the Joint Report.[177] Duke Energy stated that they had "previously demonstrated that removal of cold weather outages . . . is insignificant to the 2016 Resource Adequacy results."[178] Duke Energy also stated that in private meetings with the Public Staff, Astrapé demonstrated that changes in the load forecast uncertainty modeling would not impact the winter to summer or hourly LOLE relationships.[179] Duke Energy also stated that "regarding the removal of the short duration

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[173] *Id.* at p. 38.
[174] *Id.* at p. 39.
[175] *Duke Reply Comments*, p. 59.
[176] *Id.*
[177] *Id.*
[178] *Id.*
[179] *Id.*

winter outages from the outage rate data, Astrapé also demonstrated to the Public Staff that the impact of removing outages would result in only a modest change . . . [w]hich resulted in a slight shift of LOLE from the winter to the summer, again resulting in the Companies' initial seasonal weighting proposal remaining essentially unchanged."[180] In response to SACE's comments regarding the relationship between temperature and load at extremely cold temperatures, Duke Energy stated that it had performed a sensitivity analysis that showed only a very small decrease in the reserve margin.[181] Duke Energy noted that the Public Staff was satisfied with this approach, and therefore SACE's comments on the subject should be rejected. Duke Energy also questioned Witness Wilson's statement, in his report, that the 2016 RA Studies exaggerate winter risk by using unrealistic operating reserve assumptions. While Witness Wilson stated in his report that the RA Studies held over 1,000 MW for DEC and 750 MW for DEP of operating reserves, Duke Energy stated that the RA studies and *Solar Capacity Value Study* only held 216 MW in DEC and 134 MW in DEP.[182] Duke Energy did not provide a citation for this statement. Finally, Duke Energy argued that increasing winter DSM to summer levels was unrealistic and not cost effective.[183]

In his direct testimony, Witness Wilson critiqued the Rate Design Stipulation for its statement that "it is reasonable and appropriate for the Companies' seasonal and hourly allocations of capacity payments to be based on the loss of load risk identified in the

[180] *Id.* at 61.
[181] *Id.* at 62.
[182] *Id.*
[183] *Id.* at pp. 63-66.

Astrapé Solar Capacity Value Study."[184] Witness Wilson recommended that the Rate Design Stipulation be rejected and Duke Energy be required to adopt more balanced seasonal capacity cost weightings.[185] Witness Wilson also recommended that in future resource adequacy studies Duke Energy should study the relationship between extreme cold and conditions, taking into account relevant factors such as likely facility closures and the impacts of wind speeds; research the drivers of sharp winter load spikes under extreme cold conditions and develop programs for shaving these rare and brief spikes; research the potential for load forecast errors due to economic and demographic forecast errors; and provide more detailed information including model reports and comprehensive sensitivity analyses.[186]

In his testimony, Witness Snider stated that Duke Energy had "previously fully responded" to Witness Wilson's recommendations in reply comments and in the Sub 157 2018 IRP proceeding.[187] At the hearing, Public Staff Witness Thomas stated that in his perspective, "the items that Mr. Wilson has brought up have been . . . addressed" and would be reviewed when Duke Energy does their next reserve margin study. [188] Witness Thomas also acknowledged that the issues raised by Witness Wilson in this proceeding overlapped with issues pending before the Commission in the 2018 IRP proceeding.[189]

Multiple parties expressed concern about the avoided energy rate design proposals filed by the Utilities in their initial statements. The Public Staff wrote that, "In light of

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[184] Tr. Vol. 5, p. 337, ll. 11-12.
[185] *Id.* at p. 340, ll. 1-8.
[186] *Id.* at p. 341, ll. 4-18.
[187] Tr. Vol. 2, p. 129, ll. 1-3.
[188] Tr. Vol. 6, p. 64, l. 24 – p. 65, ll. 4.
[189] *Id.* at p. 65, ll. 5-9.

current and future potential uses of avoided cost hours and rates, the Public Staff believes that additional granularity, beyond that proposed by Duke and DENC in this proceeding, is appropriate and beneficial to North Carolina ratepayers."[190] The Public Staff went on to state that:

> [M]ore granular pricing would signal a dispatchable QF to provide energy during times when the Utilities are most likely to operate their highest marginal cost generation units, thus avoiding the need to run those units, and would also provide clear price signals to developers interested in adding new technologies, such as energy storage, to their intermittent facilities. Avoided energy rates that accurately reflect the Utilities' highest production cost hours (lambdas) increase the likelihood that the interests of ratepayers and developers align.[191]

Similarly, NCSEA wrote that "DEC, DEP, and DENC all propose oversimplified daily on-peak and off-peak rates that average time periods with distinctly different cost characteristics. These proposals are made despite the fact that the Utilities have detailed avoided cost data available for all 8,760 hours for each of the next 10 years."[192] NCSEA also identified that "the Utilities have failed to propose rates based on the characteristics of QF-supplied power, but have instead proposed a punitive charge for such QFs[]" [193] and that "the Utilities have also failed to provide the Commission with 'data sufficient for the parties and the Commission to evaluate the appropriateness of such a rate in their initial filings[.]'"[194]

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[190] *Public Staff's Initial Comments*, p. 54.
[191] *Id.* at p. 54.
[192] *NCSEA's Initial Comments*, p. 28 (internal citations omitted).
[193] *Id.* at p. 35 (internal citations omitted).
[194] *Id.* (internal citations omitted).

DISCUSSION AND CONCLUSIONS

On June 27, 2017, in Docket No. E-100, Sub 147, the Commission issued an Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans. In the 2016 IRP Order, the Commission concluded that the electric utilities' peak load and energy sales forecasts were reasonable for planning purposes. However, the Commission expressed concern about DEC's forecast.

> The Commission further concludes that the DEC load forecast may be high. In reaching this conclusion, the Commission recognizes the Wilson Report.[195] To quote from Mr. Wilson's report, "Overall, the DEC winter peak forecast seems somewhat high compared to the trend in the weather-adjusted peaks . . ." Mr. Wilson notes in his report on page 9 that for DEC, there has been a steady differential between the weather-adjusted summer and winter peaks during recent years, averaging 750 MW over 2009 to 2016, and averaging 683 MW over 2014 to 2016. The report states that DEC's current forecast breaks from this pattern, again suggesting that the winter peak forecast is high (see Figure JFW-6: DEC Summer and Winter Peaks, Historical and Forecast).
>
> Continuing to address the DEC winter forecast, Mr. Wilson states in his report on page 7 that changes in end-use technologies may be affecting these brief, extreme winter peak loads under extreme cold conditions. The report points out that DEC stated it has not performed any formal analysis to determine which end uses are contributing to these load spikes on extremely cold winter mornings (response to Data Request SACE 2-11).[196]

As a result, the Commission directed DEC to address in its 2017 IRP Update any refinements in its load forecasting methodology.[197]

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[195] On behalf of Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council (hereinafter, SACE), James F. Wilson of Wilson Energy Economics prepared a report entitled "Review and Evaluation of the Peak Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans" (Wilson Report).
[196] *2016 IRP Order* at p. 15.
[197] *Id.*

On August 27, 2019, the Commission issued an Order Accepting Integrated Resource Plans And REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses in the E-100, Sub 157 docket, in which it declined to accept "some of the underlying assumptions upon which DEC's and DEP's IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020."[198] The Commission's 2018 IRP Order also scheduled an oral argument for January 8, 2020, to further consider Witness Wilson's concerns, among other issues, regarding Duke Energy's load forecasts and reserve margins.[199]

The Commission recognizes that the issues raised by Witness Wilson here overlap with those scheduled for oral argument by the Commission's 2018 IRP Order. In light of the Commission's outstanding concerns regarding Duke Energy's load forecasts and reserve margins, the Commission declines to adopt the Rate Design Stipulation's language providing that it is "reasonable and appropriate for the Companies' seasonal and hourly allocations of capacity payments to be based on the loss of load risk identified in the Astrapé Solar Capacity Value Study."[200] The Commission further declines to adopt Duke Energy's proposed seasonal capacity allocation of 100%/0% winter/summer capacity payment weighting for DEP and a 90%/10% weighting for DEC. The Commission finds it appropriate to temporarily revert to the previous seasonal allocations approved in the E-100 Sub 140 proceeding,[201] which did not rely on the studies in controversy, pending an

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[198] *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses*, p. 7, Docket No. E-100, Sub 157 (August 27, 2019).
[199] *Id.* at p. 89.
[200] *See* Tr. Vol. 5, p. 337, ll. 11-12.
[201] The Commission's *Sub 140 Phase I Order* approved a "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

order following the oral argument on these issues scheduled on January 8, 2020 and any subsequent consideration by the Commission. In the next biennial avoided cost proceeding, which will follow the issuance of an order addressing the Commission's concerns regarding Duke Energy's load forecasts and reserve margins, the Commission will revisit the issue of seasonal capacity weighting and determine whether a departure from the previous winter and summer seasonal allocation is warranted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

SUMMARY OF THE EVIDENCE

The Commission's *Sub 148 Order* stated that "DEC [and] DEP . . . shall calculate avoided capacity rates using the peaker method and include a levelized payment for capacity over the term of the contract that provides a payment for capacity in years that the utility's IRP forecast period demonstrates a capacity need."[202]

In its initial filings, Duke Energy asserted that it had developed DEC and DEP's avoided capacity rates consistent with the *Sub 148 Order* and H.B. 589 to recognize each utility's next avoidable future capacity need based upon the Companies' most recent biennial IRPs.[203] Duke Energy asserted that DEC's next avoidable capacity need is a planned 460 MW (winter rating) of combustion turbine unit ("CT") capacity in 2028, while DEP's next avoidable capacity need is a planned 30 MW short-term market capacity purchase in 2020.[204]

80%/20% (summer/non-summer) weighting for DEC Option A." It is appropriate to default to the 60%/40% seasonal capacity allocation, which encompassed the majority of contracts signed under the Sub 148, and is not tainted by the problematic 2016 RA Studies.

[202] *Sub 148 Order*, Ordering Paragraph 4.

[203] *Duke Initial Statement*, pp. 12.

[204] *Id.* at p. 13.

In its initial comments, NCSEA noted that DEC's 2018 IRP shows a 30 MW short-term market capacity purchase in 2020, and uprates at existing units scheduled for 2021, 2022, 2023, 2024, and 2025.[205] NCSEA asserted that market purchases of power and uprates at existing units should be relevant in determining an avoidable capacity need, and that Duke Energy had not explained whether or not these planned capacity expansions could be met by small power producers.[206] In its initial comments, SACE also noted that the lack of detail regarding uprates was problematic because if the uprates required a capital investment, that capacity should be reflected in the Companies' avoided capacity rates.[207]

In its reply comments, Duke Energy asserted that near-term designated capacity additions, including the nuclear uprates identified by NCSEA and SACE, were not recognized as an avoidable capacity.[208] Duke Energy stated that these nuclear uprates are operation and maintenance related investments and not new, undesignated capacity additions that could be avoided by QFs.[209]

DISCUSSION AND CONCLUSIONS

The Commission reaffirms its finding in the *Sub 148 Order* that DEC and DEP shall "include a levelized payment for capacity over the term of the contract that provides a payment for capacity in years that the utility's IRP forecast period demonstrates a capacity need."[210]

The Commission finds persuasive NCSEA and SACE's comments that planned

[205] *NCSEA's Initial Comments*, p. 11.
[206] *Id.*
[207] *SACE Initial Comments*, pp. 13-14.
[208] *Duke Initial Statement*, p. 39.
[209] *Id.* at p. 40.
[210] *Sub 148 Order*, Ordering Paragraph 4.

capacity expansions through uprates could potentially be met by small power producers, and that more detail is necessary to determine whether the uprates included in the Companies' IRPs constitute capacity expansions that could be avoided by a QF. The Commission notes that the Companies have the burden of proof to demonstrate that an apparent capacity need cannot be met by a QF. In the absence of evidence on the record regarding whether or not nuclear uprates constitute a capacity expansion that could be met by avoided by a QF, the Commission declines to accept Duke Energy's assumption that the QFs could not help avoid the need for future nuclear uprates. The Commission recommends that Duke Energy revise its capacity assumptions and provide a detailed explanation regarding the degree to which the capacity expansions created through nuclear uprates could be avoided by QFs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

SUMMARY OF THE EVIDENCE

In his affidavit, NCSEA Witness Johnson noted that DENC calculates avoided costs based on an in-service date of January 1, 2019.[211] NCSEA Witness Johnson noted that "That is an arbitrary, and obviously unrealistic, assumption about when QFs qualifying for the avoided cost rates established in this proceeding will be placed in service, or the time period which will apply to the rates set in this proceeding[,]"[212] and recommended that "Since the standard offer tariff establishes a single set of rates that apply to all QFs eligible for the tariff, regardless of when they are placed in service, it is appropriate to use

[211] Johnson Affidavit, p. 58.
[212] *Id.* at p. 58.

a less arbitrary, more reasonable, estimate of when that will first occur."[213] In his direct testimony, NCSEA Witness Johnson noted that

> In their direct testimony, the utilities made very little effort to defend their assumed in-service date of January 1, 2019, nor did they offer any response to my concern that this assumption distorts all of the avoided cost calculations. Rather than just admitting the January 1, 2019 assumption is inaccurate, or offering to change this assumption, they concentrated on criticizing the alternative date of December 31, 2021 which I suggested in my affidavit.[214]

DISCUSSION AND CONCLUSIONS

NCSEA Witness Johnson testified that "An inaccurate in-service date leads to inaccuracies throughout the rate-setting process."[215] The Commission agrees with NCSEA Witness Johnson that "it is completely unrealistic to assume an in-service date of January 1, 2019 for QFs that sign a contract during the 2019-2020 biennial period.[216] While the Utilities disagreed with NCSEA Witness Johnson's suggestion that avoided costs should be calculated utilizing an in-service date of December 31, 2021, the Utilities neither supported the in-service date of January 1, 2019 utilized in their avoided cost calculations nor provided any evidence to support a date other than December 31, 2021, as suggested by NCSEA Witness Johnson. Based on the evidence presented in this proceeding, the Commission concludes that it is appropriate to calculate avoided costs utilizing a presumed in-service date of December 31, 2021.

[213] *Id.* at p. 59.
[214] Johnson Direct, pp. 17-19.
[215] *Id.*
[216] *Id.* at pp. 22-26.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

SUMMARY OF THE EVIDENCE

North Carolina has historically utilized the "peaker method" for calculating avoided cost, and continues to do so in the instant proceeding. Under this method, avoided capacity rates are calculated based upon the fixed costs of a combustion turbine (CT) peaker generating facility.[217] Duke now argues that its system is winter peaking, and is attempting to allocate most of the avoided capacity rates to the winter season. The Commission notes that periods of cold weather are exactly when natural gas demand peaks and pipeline capacity is constrained. NCSEA argues that, in order to ensure reliable operation, CTs need to be served with firm pipeline capacity, to be assured of receiving gas supplies, or to have a backup supply of an alternative fuel (oil).[218] NCSEA further argues that, given current fuel pricing, procuring firm pipeline capacity is the more cost-effective solution, and as such the costs of securing firm pipeline capacity should be included when calculating avoided capacity costs.[219]

In response, Duke makes two arguments. First, Duke argues that it does not reserve firm pipeline capacity for CTs.[220] The Commission has concerns about this practice, and will address the reasonableness and prudency of this decision in future fuel rider proceedings. Second, Duke argues that it is inappropriate to include firm pipeline capacity costs when calculating avoided capacity rates for a winter peak but not for a summer

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[217] *See, e.g., Sub 148 Order*, p. 6; *Sub 140 Phase I Order*, p. 48; *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, pp. 7-8, Docket No. E-100, Sub 136 (February 21, 2014).
[218] *NCSEA's Initial Comments*, pp. 23-24.
[219] *Id.*; Beach Affidavit, p. 4.
[220] *Duke Reply Comments*, p. 35.

peak.[221]

DISCUSSION AND CONCLUSIONS

The Commission is not persuaded that the distinction drawn by Duke is relevant. The fundamental purpose of a peaker plant is to supply electricity during periods of high demand. A peaker plant cannot supply electricity if it does not have access to the fuel that it uses to generate electricity. The Commission does not agree with Duke that including an operating cost, such as the cost of procuring firm pipeline capacity, in the avoided capacity calculation represents a fundamental departure from the peaker method of calculating avoided costs.[222] As such, the Commission finds that it is appropriate to include the costs for firm natural gas transportation to a CT when calculating avoided capacity rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

SUMMARY OF THE EVIDENCE

In its initial comments, the Public Staff noted "that DEC and DEP have retired, and plan to retire over the next 10 years, significant natural gas and coal generation that may lead to the availability of several 'brownfield' sites for future use for both baseload and peaking needs."[223] The Public Staff went on to recommend "that DEC and DEP evaluate the use of appropriate adjustments to the EIA data to reflect the potential for utilizing brownfield sites for some portion of their generation additions, and include such evaluation in their next avoided cost filing."[224]

In their reply comments, NCSEA disagreed with the Public Staff's

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[221] *Id.*
[222] *Id.*
[223] *Public Staff's Initial Comments*, p. 67.
[224] *Id.* at p. 69.

recommendation, stating that:

> The issue with the Public Staff's suggestion that Duke rely upon brownfield rather than greenfield costs is that Duke has not projected enough open brownfield locations for capacity additions. As the Public Staff notes – Duke has not proscribed the use of brownfield sites in their avoided cost calculation in their next avoided cost proposal. Therefore, the Public Staff is, on its own accord, changing the avoided cost calculus in such a way that will cause it to suppress installed costs and lower the capacity payments in the next filing. To this point, in the 2018 Integrated Resource Plan filings, Duke only identified two future capacity additions that will occur at brownfield locations, and both of these facilities have already received certificates of public convenience and necessity ("CPCNs") from the Commission: in DEC, the "402 MW Lincoln CT 17 included in December 2024[;]"and, in DEP, the "560 MW Asheville combined cycle addition in November 2019." Given that Duke predicts only two capacity additions which may be brownfield sites, and that neither site is incorporated into its avoided cost peaker plant calculations, Duke does not appear to intend to utilize numerous brownfield sites and, instead, may have used the EIA-formula utilizing greenfield sites for good reason.[225]

<u>DISCUSSION AND CONCLUSIONS</u>

North Carolina utilizes least-cost planning when determining where and when to construct new generation. When it is reasonable and prudent to do so, the Commission expects the Utilities to site new generation at brownfield locations where installed costs may be reduced due to pre-existing infrastructure. However, the Commission is not convinced that it should assume, for purposes of calculating avoided costs, that new peaking generation will be located at brownfield sites when the Utilities' IRPs do not specify that new generation will be constructed at brownfield sites. As noted by NCSEA, the two new generation units being constructed by Duke at brownfield locations have both

[225] *NCSEA's Reply Comments*, p. 7, Docket No. E-100, Sub 158 (March 27, 2019) (internal citations omitted).

already received CPCNs, and none of the new generation units planned in Duke's IRPs are expected to be constructed at brownfield sites. As such, the Commission is not convinced that avoided costs should be calculated utilizing brownfield costs and directs the Utilities to continue utilizing the EIA-formula, which includes greenfield site costs, to calculate avoided costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

SUMMARY OF THE EVIDENCE

In its initial statement, Dominion proposes establishing a cap on the annual capacity payment for intermittent QFs.[226] In essence, "the cap would be applied to a solar facility that has 'reduced output, relative to its nameplate capacity, during early morning hours on cold winter days, and during mid-afternoon hours on hot summer days.'"[227] According to the Public Staff, Dominion's proposed cap would apply to tracking solar facilities with a capacity factor above 25.8%, while the Public Staff's examination found that the maximum capacity factor in Dominion's service territory was 25.1%.[228]

DISCUSSION AND CONCLUSIONS

While Dominion's capacity payment cap may be of limited applicability at this time, the Commission shares the concerns about the cap expressed by the Public Staff and NCSEA. The Public Staff aptly observed "that PURPA specifically authorized states to consider, to the extent practical for calculating avoided costs, '[t]he availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods.'"[229]

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[226] *See Public Staff's Initial Comments*, p. 60.
[227] *Id.* at p. 60 (internal citations omitted).
[228] *Id.* at pp. 61-62 (internal citations omitted).
[229] *Id.* at pp. 63-64 (internal citations omitted).

The Commission notes that, since Dominion utilizes the PJM system peaks when calculating avoided costs and PJM is a summer-peaking system, solar QFs that provide capacity on summer afternoons would be providing capacity during seasonal peak periods. As such, the Commission sees no compelling reason to adopt Dominion's proposed capacity payment cap. The Commission agrees with the Public Staff that, "rather than implementing a cap based on the projected capacity value of an intermittent QF relative to a fully dispatchable CT resource, DENC should instead evaluate alternative seasonal allocation and Capacity Payment Hours that align more directly to DENC's system (as opposed to the PJM system as a whole)."[230]

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

SUMMARY OF THE EVIDENCE

The vast majority of solar QFs in North Carolina have existing PPAs with Duke or Dominion under standard offer contracts approved by the Commission in previous biennial avoided cost proceedings. At the end of their existing contracts, those solar QFs will have substantial remaining useful life. The treatment of expiring PPAs in the Utilities' IRPs will directly impact the avoided capacity payments that are included in the avoided cost rates established during biennial avoided cost proceedings.

In his Direct Testimony, Duke Witness Snider states that:

> the Companies' IRPs have consistently and appropriately assumed that all wholesale purchase contract capacity is removed in the year after a wholesale contract expires and that QFs are not presumptively assumed to establish a new legally enforceable obligation ("LEO") to deliver capacity and energy to the utilities over a new fixed term in the future. At the time any merchant wholesale generator, including a QF, executes a PPA and commits itself to deliver energy and capacity over a future term, the

[230] *Id.* at pp. 63-64 (internal citations omitted).

Companies would then recognize the committed energy and capacity for IRP planning purposes, including as "existing capacity" for purposes of determining the utility's need for additional capacity in the future.[231]

However, Public Staff Witness Hinton testified that:

> In response to data requests submitted by the Public Staff and other parties, Duke indicated that for planning purposes, it also assumes that purchase power agreements (PPAs) are expected to be either renewed or replaced in kind. The assumptions as to renewal of wholesale power contracts as opposed to solar PPAs appear to be in conflict and indicate potentially different treatment of QF contracts.[232]

Public Staff Witness Hinton went on to testify that, based on discussions with Duke, "the Public Staff understands that in order to establish the first year of needed capacity for avoided cost purposes, DEC and DEP utilize a parallel IRP expansion plan that does not include the Company's assumption regarding the replacement of in-kind solar QF generation."[233] For this reason, the Public Staff suggested, and Duke agreed, that Duke should include a "Statement of Need section in future IRPs that identifies DEC's and DEP's first year of an avoidable need along with the supporting factors used to determine the avoidable need date."[234]

In Direct Testimony, NCSEA Witness Johnson included a proposal for how to address expiring QF PPAs and their respective capacity. NCSEA Witness Johnson identified the fact that existing "QFs are currently helping to meet the utilities' capacity needs, and there is no principled basis for ceasing to pay them for the capacity costs they are helping to avoid, once their contracts come up for renewal."[235] NCSEA Witness

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[231] Tr. Vol. 6, p. 97.
[232] *Id.* at p. 308.
[233] *Id.* at p. 311.
[234] Tr. Vol. 2, p. 99.
[235] Tr. Vol. 6, pp. 206-207.

Johnson proposed that "the Commission could require QFs to file notice with the utility at least 3 years before the current PPA expires indicating whether the QF is committing to continuously provide capacity and energy (without interruption) after the current contract expires - and specifying the length of that capacity commitment."[236] With respect to the connection to Duke's IRPs and the respective capacity needs, NCSEA Witness Johnson explains:

> To the extent the QF confirms its capacity will be continuously available, the utility would include that capacity in the IRP - treating it as a committed generation resource, and the QF would be entitled to receive full avoided capacity payments without interruption for the full duration of the commitment period (with the actual payment rate and other details to be determined when the new contract is signed).
>
> If a QF does not make a post-contract commitment, it will retain maximum flexibility to choose its course of action when the existing contract expires - including the option to sell power on an energy-only "as available" basis, or to sign a new fixed price contract at the same terms applicable to a new QF (e.g. with little or no capacity payments).
>
> If the QF does not make a capacity commitment, or it only commits to a short period of time, the utility would exclude the QF's capacity from the IRP at the end of the contract term or commitment period. The removal of that capacity would be factored into the calculation of the extent to which a "need" for capacity exists each year - similar to the calculations that are developed when an existing generating plant is scheduled for retirement, or a wholesale purchase contract is expiring and is not expected to be renewed.[237]

DISCUSSION AND CONCLUSIONS

As an initial matter, the Commission notes that no party has objected to requiring Duke to include a Statement of Need in future IRPs. As such, the Commission directs Duke to do so.

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[236] *Id.* at p. 200.
[237] *Id.* at pp. 214-215.

The Commission believes that NCSEA Witness Johnson's proposal strikes the appropriate balance between the need for certainty as to the QFs commitment to renew its contract and allowing an existing QF to continue to receive compensation for the uninterrupted capacity it continues to provide to Duke. This position appears consistent with Duke's statement in its Reply Comments that if "QFs have already begun contract extension or renewal negotiations with the Companies, the specific contract capacity may be included past the current contract expiration year to the expected year of expiration of the extended/new contract."[238] Inasmuch as NCSEA Witness Johnson's proposal does not address the specifics of how such a notice should be made, the Commission will require the parties to engage in stakeholder discussions to make recommendations on any additional terms that would need to be addressed, including any appropriate penalty for a QF that committed to renew its contract and failed to do so. The parties may also choose to reach agreement on an alternative approach along the lines suggested by NCSEA and NCCEBA under which QFs with existing PPAs would be able to compete to supply future capacity needs that are identified prior to (including based on) the expiration of their existing PPAs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 22-23

SUMMARY OF THE EVIDENCE

The Commission's *Sub 148 Order* provided that "DEC and DEP shall recalculate their avoided energy rates using forward natural gas prices for no more than eight years

[238] *Duke Reply Comments*, pp. 46-47.

and fundamental forecasts for the remainder of the planned period."[239] In its initial filings, Duke Energy stated that their avoided energy calculations rely on ten years of forward natural gas market price data.[240]

In its initial comments SACE critiqued Duke Energy's reliance on ten years of forward pricing, arguing that reliance on long-term forward pricing is inappropriate because future markets are not good indicators of long-term market trends.[241] SACE recommended that the Commission require Duke Energy to rely on no more than two to three years of forward market price forecasts before transitioning to a blended forecast, and then a fundamental price forecast. SACE noted that Dominion Energy's use of 18 months of natural gas pricing, 18 months of blended natural gas forward pricing, and ICF pricing beyond 36 months provided a more accurate approximation of long-term avoided energy costs.[242]

Similarly, NCSEA objected to the form and methodology that Duke used in developing its natural gas forecast. NCSEA noted that "Duke's method undermines its fundamentals forecast."[243] NCSEA explained that

> Forward prices and fundamentals forecasts each play a role in a reasonable gas price forecast: forward prices provide market-based information on short-term price trends influenced strongly by (1) current demand, by (2) near-term expected demand, and by (3) the current status of gas in physical storage. While forward prices represent the future price parties are willing to contract for now, these amounts are not necessarily what the price for those future supplies will be in the future. Forward prices often track current prices, and the magnitude of the forward price curve shifts up or down

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[239] *Sub 148 Order*, Ordering Paragraph 5.
[240] *Duke Initial Statement*, p. 18.
[241] *SACE Initial Comments*, pp. 6-7.
[242] *Id.* at p. 7.
[243] *NCSEA's Initial Comments*, p. 14 (internal citations omitted).

> largely in parallel to changes in the current spot price. While there is some evidence that short-term forward prices provide a reasonable forecast of short-term spot prices, Duke does not provide evidence that ten years of forward price data is superior to forecasts that examine the fundamentals of the supply and demand of natural gas.[244]

NCSEA went on to recommend Duke utilize:

> a balanced forecast that uses forward market prices for two years while the market is robust and deep, with a transition in the next three years to the average of a set of recent fundamentals forecasts, which NCSEA believes should come from (1) DNCP's forecast from ICF and (2) the new *2019 AEO* forecast from EIA, is a more appropriate forecast to use. Alternatively, NCSEA would not object to the use of Dominion's similar forecast methodology of 18 months of forwards transitioning to a fundamentals forecast beginning at 36 months for all of the Utilities.[245]

DISCUSSION AND CONCLUSIONS

The Commission notes that this issue was extensively litigated in the Sub 148 proceeding in addition to the instant proceeding. At that time, the Commission directed Duke "to recalculate their avoided energy rates using forward natural gas prices for no more than eight years before using fundamental forecast data for the remainder of the planning period."[246] The Commission noted at that time that it was "satisfied that at the present time the number of such transactions is sufficiently fewer to prevent the Commission from relying completely on this method for establishing energy prices in this case at this time and will continue to monitor the liquidity in the market in future avoided cost proceedings."[247]

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[244] *Id.* at p. 18 (internal citations omitted).
[245] *Id.* at p. 19.
[246] *Sub 148 Order*, p. 7.
[247] *Id.* at pp. 77-78.

As in the Sub 148 proceeding, the Commission does not believe that there are sufficient transactions in the futures market to establish liquidity for 10-year futures, and as such the Commission cannot adopt the methodology proposed by Duke in the current proceeding. Therefore, the options before the Commission are the methodology proposed by NCSEA and SACE and the Sub 148 methodology.

The Commission notes that Duke did not provide any evidence in the current proceeding supporting the Sub 148 methodology or its departure from it, which utilized eight years of futures before transitioning to fundamentals. The evidence in the current proceeding also makes clear that few, if any, QFs entered into Sub 148 standard contract PPAs. Given this, the Commission believes it would be inappropriate to utilize the Sub 148 fuel forecasting methodology. As such, the Commission directs Duke to utilize a fuel forecasting methodology that utilizes of 18 months of natural gas pricing, 18 months of blended natural gas forward pricing, and ICF pricing beyond 36 months.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 24-25

SUMMARY OF THE EVIDENCE

In its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in the E-100, Sub 140 Docket ("Sub 140 Order"), the Commission directed the Utilities to include a fuel price hedge value in the Company's avoided energy calculations.[248] The Commission provided that "there are fuel price hedging benefits associated with solar generation" and therefore "[i]t is appropriate to recognize those

[248] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, p. 30-31, Docket No. E-100, Sub 140.

hedging costs that are avoided as a result of energy purchases from QF generation."[249] In the Sub 140 proceeding, Duke Energy and Dominion Energy accepted the Public Staff's proposed hedge value of 0.028 cents per kWh in a Memorandum of Understanding filed on February 2, 2016.[250] Both Duke Energy and Dominion included a fuel price hedge value in their avoided cost calculations in the Sub 148 proceeding, and Dominion Energy continues to include a fuel price hedge value in the current proceeding.[251]

In its initial filings Duke Energy proposed to eliminate the fuel price hedge value from its avoided cost rates.[252] Duke Energy stated that the relationship between QFs and the Utilities established by PURPA constitutes a "Put Option" which subjects the Utilities and their customers to overpayment risk.[253] Duke Energy stated that it is not "recommending applying this charge to QFs at this time" but that it would be appropriate to eliminate the 0.028 cents per kWh fuel price hedge value in light of the existence of the Put Option.[254]

In its initial comments SACE critiqued Duke Energy's proposal to eliminate the fuel price hedge value. SACE argued that Duke Energy is not entitled to compensation for the legal right PURPA grants QFs to sell energy and capacity to utilities at the avoided cost rates.[255] SACE explained that a QF is not required to purchase the right to sell energy and

[249] *Sub 140 Phase I Order*, p. 42.
[250] *Memorandum of Understanding by and between Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Dominion North Carolina Power and the Public Staff of the North Carolina Utilities Commission in Support of Recalculation of Avoided Cost Rates*, Docket No. E-100, Sub 140 (Feb. 2, 2016).
[251] *Duke Initial Statement*; *Dominion Initial Statement*, Exhibit DENC-6.
[252] *Duke Initial Statement*, p. 22.
[253] *Id.* at p. 22.
[254] *Id.*
[255] *SACE Initial Comments*, p. 9.

capacity under PURPA because Congress and FERC have expressly granted QFs that right.[256] Furthermore, SACE asserted that even if a Put Option did exist, Duke Energy had failed to meet its burden of proof, N.C.G.S. §62-75, by failing to actually calculate the value of the Put Option, and instead assuming that its value equals the fuel price hedge value.[257] SACE concluded that "Duke may not circumvent its obligation to include hedging benefits in its avoided energy rates by assuming that the alleged and unsupported option premium, based on a yet-to-be-calculated value of the Put Option, is identical to the existing hedging value."[258]

In its initial comments the Public Staff also critiqued Duke Energy's proposal to eliminate the fuel price hedge value. The Public Staff characterized Duke Energy's proposal as "essentially require[ing] WFs to compensate utilities for the right to sell this generation."[259] The Public Staff concluded that "renewable generation provides additional fuel price stability that is of value" and recommended that the Commission "require DEC and DEP to calculate and include the fuel hedging benefits associated with purchases of renewable energy in their avoided energy cost rates using the Black-Scholes Option Pricing model or similar method."[260]

In its reply comments, NCSEA agreed with the Public Staff and SACE that demanding QF compensations for a Put Option would unreasonably require the QF to compensate utilities for their existing rights under PURPA.[261] NCSEA also agreed with

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[256] *Id.*
[257] *Id.* pp. 8-9.
[258] *Id.*
[259] *Public Staff's Initial Comments*, p. 28.
[260] *Id.* at 29.
[261] *NCSEA's Reply Comments*, p. 4.

SACE that since Duke had not actually calculated the value of the alleged Put Option, it had not met its burden of proof to eliminate the fuel price hedge value.[262]

In its reply comments, Duke Energy acknowledged that it is seeking to impose costs on QFs for an "option that is now being freely given to QFs under PURPA."[263] Duke Energy argued that the value of the alleged Put Option is "know and measurable" and that customers currently "receive nothing for this option."[264]

DISCUSSION AND CONCLUSIONS

The Commission recognizes that, as stated in its Sub 140 Order, "there are fuel price hedging benefits associated with solar generation" and therefore "[i]t is appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation."[265] The Commission further recognizes that in previous avoided cost proceedings both Duke Energy and Dominion have proposed hedge value of 0.028 cents per kWh in accordance with a Memorandum of Understanding with the Public Staff filed on February 2, 2016, and that Dominion continues to include this hedge value in its avoided cost calculations.

The Commission finds persuasive Public Staff, SACE, and NCSEA's argument that QFs are entitled to the "Put Option," as Duke Energy Describes it, under PURPA, and that it would be inappropriate for Duke Energy to charge QFs a fee for a right guaranteed to them by federal law. Therefore, the Commission declines to accept Duke Energy's proposal to eliminate the fuel price hedge value from its avoided cost calculations. The

[262] *Id.* at p. 5.
[263] *Duke Reply Comments*, p. 25.
[264] *Id.*
[265] *Sub 140 Phase I Order*, p. 42.

Commission finds reasonable Dominion's continued use of the Black-Scholes Option Pricing model to calculate the fuel price hedge value.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

SUMMARY OF THE EVIDENCE

In its initial filings, DEP and DEC proposed a Performance Adjustment Factor ("PAF") of 1.05. The Companies compiled five years of historic Equivalent Availability ("EA") data for the entire fleet during the months of January, February, July, and August. The Company designated these as critical peak season months, reflecting high load periods during which the Companies do not typically schedule planned maintenance outages. The respective equivalent availability during that timeframe was determined to be 95%, which translates to a PAF capacity multiplier of 1.05. Duke Energy proposed to continue its use of a 2.0 PAF for run-of-river hydro with no storage capability under 1 MW. In support of this position, the Companies stated that they 2014 Hydro Stipulation was negotiated in good faith, and that North Carolina has a policy of supporting small hydro, and there is a finite amount of small hydro capacity in the state.[266]

In its initial filings, Dominion proposed a PAF of 1.07, using the EA metric. The EA represented the availability of units during a defined period and accounts for unavailability due to planned, maintenance, and forced outages. Dominion provided a summary table of historical fleet-wide EA rates, and used June, July, August, and January-February as peak season months. According to Dominion, PJM considers these to be critical months when system emergencies and performance assessment hours are

[266] *Duke Initial Statement*, pp. 15-17.

expected.[267] Dominion did not take a position on the 2.0 PAF approved in a settlement between DEC, DEP and the NC Hydro group in the 2014 avoided cost proceeding due to the lack of hydro QF activity in Dominion's North Carolina territory.[268]

NCSEA pointed out in its initial comments that the PAF is designed to ensure that QFs "are not discriminated against in favor of rate-based generation."[269] NCSEA stated that ratepayers pay the full cost of rate-based capacity even when that capacity is not available during critical peak hours, whereas QF capacity payments are tied to the amount of energy QFs provide during specific hours. Thus, the PAF should consider actual availability of rate-based generation during all critical peak hours. NCSEA took particular issue with Duke Energy's designation of peak hour months for purposes of calculating its EA, and a proposed PAF of 1.05. In particular, NCSEA noted that Duke Energy has designated additional critical peak months in other contexts, including Duke Energy's proposed rate design changes in this proceeding, and noted that Duke Energy has not claimed that these are the only months when peaks can occur. NCSEA also noted that the difference in the proposed PAF between Duke Energy and Dominion was due, at least in part, to a difference in peak month designations.[270] NCSEA argued for increasing the range of Duke Energy's critical peak months for purposes of the PAF calculation to include peak months between June – September and December – March, and filed the affidavit of Dr. Ben Johnson to further explain and support this position.[271] Based on Dr. Johnson's

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[267] *Dominion Initial Statement*, pp. 32-33.
[268] *Id.* at p. 32, n. 38.
[269] *NCSEA's Initial Comments*, pp. 30-31.
[270] *Id.*
[271] Johnson Affidavit, pp. 28-36.

analysis, he recommended a PAF for Duke Energy of 1.10.[272]

Public Staff revised its recommendations between initial and reply comments. In initial comments, the Public Staff generally agreed with the methodology used by the Utilities to calculate the PAF, but also recommended that the use of the Equivalent Forced Outage Rate ("EFOR") forward-looking data would be appropriate because the avoided cost rates are also forward looking. In particular, Public Staff recommended that the Commission direct the Utilities to recalculate their PAF using fleet weighted average peak month EFORs utilizing five years of historical data and a minimum of five years of prospective data, but in no event greater than the PPA term of 10 years. Public Staff also commented on peak month designations and said that utility data supported inclusion of June through August as summer peak months and December through February as winter peak months. Public Staff recommended that DEC and DEP should add June and December to their calculations and Dominion should add December, and all utilities should use EFOR data.[273] With regard to the related issue of Duke Energy's proposal to eliminate the fuel hedge value because the "Put Option" would offset any hedge value, the Public Staff said as follows: "The risk of overpayment was directly addressed by this Commission in the 2016 Proceeding through the elimination of capacity payments when capacity is not needed, the reduction in the PAF from 1.20 to 1.05, and the reduction of the MW threshold to be eligible to receive a Standard Contract."[274]

In its reply comments, Public Staff revised its recommendation based on

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[272] *Id.* at p. 37, para. 114.
[273] *Public Staff's Initial Comments*, pp. 69-72.
[274] *Id.* at pp. 28-29.

discussions with the Utilities and further consideration of the PAF issue. Public Staff said its initial recommendations meant to bring the peak season concept to the forefront, but that it had given greater consideration to the differences between the EA and EFOR metrics and challenges with using forward-looking data. Public Staff revised its previous recommendation to say that if a rate-based metric like EFOR is used, three to five years of historic data is appropriate. Additionally, other methods like the Equivalent Unplanned Outage Rate ("EUOR") may be appropriate in future proceedings. Public Staff revised its position to support the Utilities' PAF proposals in this proceeding but recommended that the Commission direct the parties to further discuss the appropriate PAF metric in future avoided cost proceedings. The Public Staff did not object to continued use of a 2.0 PAF for run-of-river hydro without storage capability that are one MW and below.[275]

In reply comments, NCSEA agreed with Public Staff that the PAF should be more forward-looking as technology improves, but encouraged a stronger position from Public Staff. Namely NCSEA reiterated its concerns that Duke Energy biased its PAF calculations in a way that discriminates against QFs and understates their contribution to capacity during peak months. NCSEA stood by its recommendation to approve a PAF in the range of 1.08 to 1.10 for Duke Energy. NCSEA further agreed with Public Staff's position that the reduction in the PAF in the Sub 148 proceeding was meant to address the risk of overpayment and thus the fuel hedge value should not be removed in this proceeding.

In reply Comments, SACE agreed with NCSEA and Public Staff recommendations

[275] *Reply Comments of the Public Staff*, pp. 14-16, Docket No. E-100, Sub 158 (March 27, 2019) ("*Public Staff Reply Comments*").

to expand the peak month designations for the PAF calculations. SACE also agreed with Public Staff and NCSEA regarding the point that the Commissions reduction in PAF in the Sub 148 avoided cost proceeding was one of the determinations that addressed overpayment risk, and that Duke Energy's proposal to eliminate the fuel hedge value in this proceeding is unwarranted.[276]

The Hydro Group in initial comments supported Duke Energy's proposal to continue a 2.0 PAF for run-of-river hydro without storage as set forth in the 2014 Hydro Stipulation, including for standard offer facilities up to 1 MW in size, and up to 5 MW in size for QFs subject to the Hydro Stipulation, and asked the Commission to approve that continuation. The Hydro Group noted the state's policy of supporting hydro QFs, and there is a relatively small and finite amount of small hydro QF capacity in the state.[277] The Hydro Group reinforced its position in reply comments that the 2.0 PAF should be available for run-of-river hydro without storage up to 5 MW in size, and not just up to 1 MW in size, given that there are only ten small hydro facilities between 1 MW and 5 MW. Further, a reduction of almost 50% in the PAF coupled with the lower avoided cost rates proposed in the proceeding would be financially devastating to those facilities. If the PAF is reduced, it is unlikely they would renew their contracts and would instead shut down.[278]

In its reply comments, Duke noted that it did not oppose the Public Staff's recommendation as an alternative quantification of the PAF, subject to certain

[276] *Reply Comments of the Southern Alliance for Clean Energy*, p. 3, Docket No. E-100, Sub 158 (March 27, 2019) ("*SACE Reply Comments*").
[277] *Hydro Group's Initial Comments*, p. 10, Docket No. E-100, Sub 158 (February 12, 2019).
[278] *Hydro Group's Reply Comments*, p. 2, Docket No. E-100, Sub 158 (March 27, 2019).

clarifications.[279] Duke noted its objection to including June and December as critical peak season months, along with January, February, July, and August, but stated that it is agreeable to include those months to quantify the PAF using the Public Staff's recommended methodology.[280] Upon re-running the calculations under the Public Staff's recommended methodology, Duke noted that "both approaches generally arrive at consistent results and support a PAF of 1.05 or slightly lower."[281]

In its reply comments, Dominion recognized comments from Intervenors and stated its belief that three years of EA history should be used rather than five years, since the older data may be less relevant due to generation changes. Dominion stated that use of forward-looking data would be more subjective and unnecessarily complicated. Dominion did not support a shift to the (W)EUOR metric as contemplated by Public Staff for discussion in future proceedings because it is an obscure metric not currently calculated by the company. Dominion also disagreed with the proposal to designate additional peak months, because its proposal matches PJM's peak month designations and generator outages scheduled in the spring can start in March and fall outages can extend to December.[282]

<u>DISCUSSION AND CONCLUSIONS</u>

The Commission determines that the PAF continues to be appropriate to ensure non-discriminatory treatment against QFs. *See* FERC Order No. 69 at 12,222-12,223. The Commission reaffirms its conclusion in the E-100 Sub 148 Order that the availability of a CT is not determinative for purposes of calculating a PAF, and that the Equivalent

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[279] *Duke Reply Comments*, p. 51.
[280] *Id.* at pp. 51-52.
[281] *Id.* at p. 54.
[282] *Dominion Reply Comments*, pp. 39-42.

Availability factor is an appropriate means of quantifying the PAF at this time, but directs the parties to discuss whether the use of alternative metrics and forward-looking data is appropriate in future avoided cost proceedings as recommended by Public Staff. The Commission also finds persuasive Public Staff's initial comments and NCSEA's comments and expert affidavit from Dr. Johnson recommending additional peak hour designations. The Commission directs Duke Energy to use the 1.10 PAF as calculated by Dr. Johnson, reflecting additional peak month designations. The Commission approves Dominion's 1.07 PAF as it was largely unopposed. The Commission further approves continued use of a 2.0 PAF for run-of-river hydro without storage capability for facilities up to 5 MW in size as recommended by the Hydro groups, continuing the terms of the 2014 settlement which has been largely unopposed.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 27-28

SUMMARY OF THE EVIDENCE

The Commission's E-100, Sub 140 Order recognized the line loss avoidance benefits associated with siting QFs on the distribution grid closer to the load and ordered the Utilities to continue to include adjustments for line losses in their avoided cost inputs.[283] In the Sub 148 proceeding, DENC proposed eliminating line loss avoidance value from the avoided energy calculation due to backflows, and the Commission accepted this proposal.[284] The Commission concluded "that based on the number and aggregate size of QF projects that are seeking to interconnect to Dominion's electric system, backflows are

[283] *Sub 140 Phase I Order*, p. 10, 36-37.
[284] *Sub 148 Order*, pp. 108-10.

likely to occur more frequently on more distribution circuits in the future . . . this development greatly reduces or eliminates the benefits of solar QFs line loss avoidances."[285]

In its initial filings, Dominion again proposed eliminating the line loss avoidance value from its avoided energy calculation to account for a number of transformers experiencing backflow.[286] Dominion's initial comments stated that the number of transformers experiencing backflow has increased since the 2016 proceeding as more solar distributed generation has become operational.[287] Specifically, Dominion stated that of the 38 transformers with solar distributed generation connected, 16 transformers are now realizing consistent backflow, and only 2 transformers have consistent positive flow.[288]

In its initial comments SACE critiqued Dominion's proposal to eliminate the line loss avoidance value, arguing that solar QFs continue to provide line loss avoidance benefits despite some degree of backflow occurring.[289] SACE recognized that in the *Sub 148 Order* its argument that line loss avoidance benefits should be calculated was subject to two major critiques: (1) that it failed to account for the fact that QF generation was incrementally added over the course of the year, causing more backflow to occur later in the year than early in the year; and (2) that it included hours when no solar QF generation was occurring.[290] In an effort to address these criticisms, SACE retained Synapse to evaluate DENC's half-hour data associated with 28 substations connected to QFs from

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[285] *Id.* at p. 92.
[286] *Dominion Initial Statement*, p. 35.
[287] *Id.*
[288] *Id.*
[289] *SACE Initial Comments* at p. 19.
[290] *Rebuttal Testimony of J. Scott Gaskill on Behalf of DNCP*, pp. 18-22, Docket No. E-100, Sub 148 ("Gaskill Sub 148 Rebuttal"); *Sub 148 Order* at 89.

August 16, 2017 – August 15, 2019, to account for all the increased distributed solar generation added to Dominion's system since the Sub 148 proceeding. SACE also limited its analysis to hours during which solar QFs were generating energy. Even with these adjustments, Synapse determined that the two substations DENC classifies as "Positive" experience positive flows 100% of the time, the twenty substations DENC classifies as "Neutral" experience positive flows 87% of the time, and the sixteen substations DENC classifies as "Negative" experience positive flows 37% of the time.[291] Based on these findings, SACE showed that backflow from solar QFs that have interconnected since the Sub 148 proceeding has not eliminated the line loss benefits of solar QFs.[292] SACE acknowledged that the historical 3% adder may not reflect the line loss avoidance benefits that solar QFs currently provide, but asserted that complete elimination of the adder also failed to reflect line loss avoidance benefits.[293] SACE recommended that the Commission require DENC to re-calculate and include a line loss adder in its avoided energy rates.

In reply comments, Dominion disagreed with SACE's analysis and maintained that its avoided cost calculations should not include a line loss adder.[294] Specifically, Dominion critiqued SACE for not taking into account irradiance levels, and argued that by including hours with cloudy or rainy conditions in its analysis, SACE showed more hours with positive flow than Dominion substations actually experienced.[295] Dominion also asserted that SACE ignored the general trend that backflow occurs with more frequency as solar

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[291] Gaskill Sub 148 Rebuttal, p. 20.
[292] *Id.* at p. 20.
[293] *Id.*
[294] *Dominion Reply Comments*, p. 43.
[295] *Id.*

distributed generation is connected to the system.[296] Finally, Dominion asserted that even when its substations are experiencing positive flows, the "room" remaining on the transformer before it starts experiencing backflows is less than 20 MW, and therefore Dominion expects that existing backflows will continue to increase and remaining positive flows will be eroded as more solar becomes operational.[297]

DISCUSSION AND CONCLUSIONS

In the *Sub 140 Order, the* Commission recognized the line loss avoidance benefits associated with siting QFs on the distribution grid closer to the load and ordered the Utilities to continue to include adjustments for line losses in their avoided cost inputs.[298] In the Sub 148 proceeding, DENC proposed eliminating line loss avoidance value from the avoided energy calculation due to backflows, and the Commission accepted this proposal.[299] The Commission notes that in its *Sub 148 Order* it concluded that "that based on the number and aggregate size of QF projects that are seeking to interconnect to Dominion's electric system, backflows are likely to occur more frequently on more distribution circuits in the future . . . this development greatly reduces or eliminates the benefits of solar QFs line loss avoidances."[300]

The Commission acknowledges the potential for increased backflow as more solar QFs come online. However, the Commission also finds credible SACE's conclusion that since the Sub 148 proceeding most of Dominion's transformers are still experiencing positive flows during the hours when solar QFs produce energy. The Commission further

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[296] *Id.* at 44.
[297] *Id.*
[298] *Sub 140 Phase I Order*, pp. 10, 36-37.
[299] *Sub 148 Order*, pp. 108-10.
[300] *Id.* at p. 92.

agrees that this positive flow (rather than backflow) means that there is a line-loss value for the distributed solar generation that is greater than zero. Therefore, the Commission concludes that it is reasonable to include a positiveline-loss avoidance adder that reflects the current value of the avoided line loss benefits from QFs. The Commission directs Dominion to Dominion to calculate a line loss adder consistent with the analysis provided by SACE in this proceeding. Althought the value may not currently be 3%, the Commission expects that it is not zero. The Commission also concludes that Duke Energy's continued inclusion of a line-loss avoidance adder in its avoided cost calculations is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

SUMMARY OF THE EVIDENCE

In its initial comments, NCSEA argues that Duke and Dominion have failed to accurately capture the effect that wind and solar resources have on market prices.[301] New renewable generation increases electricity supplies available to the utilities and displaces the most expensive fossil-fired or market resources that would have been otherwise generated or purchased in regional power markets.[302] The addition of local renewable generation will reduce the demand which the utility places on the regional markets for electricity and natural gas.[303] The reduction in demand will cause a corresponding reduction in the price in these markets, which benefits the Utilities when each must buy power or natural gas in these markets.[304] NCSEA notes that, in other markets, the market

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[301] *NCSEA's Initial Comments*, p. 43.
[302] *Id.* at 44.
[303] *Id.*
[304] *Id.*

price suppression has been found to be between 4% and 25%.[305]

In its reply comments, Duke does not dispute NCSEA's assertion that new renewable energy generation increases electricity supplies, therefore suppressing market prices for electricity.[306] Instead, Duke asserts that such a suppression is speculative, unquantified, and not reflective of costs actually avoidable by the utility.[307] The Commission notes, however, that NCSEA has not attempted to quantify the value of the market price suppression caused by new renewable energy generation, but rather has raised the issue that such a value exists. Instead, NCSEA notes that "The Utilities in this docket have failed to account for these price benefits in their respective filings, and NCSEA requests this Commission acknowledge and require the Utilities to account for such market changes caused by distributed energy resources."[308]

DISCUSSION AND CONCLUSIONS

The Commission's goal in setting avoided cost rates is to make them as accurate to the utilities' actual avoided costs as possible. NCSEA's argument regarding market price suppression is a simple observation of supply and demand. New renewable energy increases supply, while electricity demand remains the same; therefore, the market price for electricity decreases. While no party has attempted to quantify the value of market price suppression in North Carolina to date, the Commission believes that it merits further investigation. As such, the Commission directs the Public Staff to convene stakeholders having an interest in market price suppression caused by QFs and file a report with the

[305] *Id.* at 44-45.
[306] *Duke Reply Comments*, pp. 30-31.
[307] *Id.* at 31.
[308] *NCSEA's Initial Comments*, p. 45.

Commission within 180 days regarding the status of discussions. Upon receipt of the report, the Commission will determine whether to require the Utilities include market price suppression when calculating avoided costs in their 2020 filings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

SUMMARY OF THE EVIDENCE

Granular Avoided Energy Rates

While the Rate Design Stipulation entered into by Duke and the Public Staff improves upon the energy rate design included in Duke's initial filing, it does not sufficiently address the concerns of the Commission or of other parties. NCSEA Witness Johnson identified three major areas where increased granularity and accuracy would be beneficial and feasible: (a) geographic diversity, (b) stable and predictable cost variations based on seasonal and hourly patterns, and (c) less stable and less predictable cost variations due to weather fluctuations.[309] NCSEA Witness Johnson testified that improving the QF rate design in all three of these areas, would improve economic efficiency, encourage entrepreneurial experimentation and innovation, and encourage better investment decisions.[310] NCSEA Witness Johnson noted that, while the stipulated energy rate design is a significant improvement compared to both the status quo and the rate design initially proposed by the utilities in this proceeding in one of these three areas, variations in avoided energy costs based on seasonal and hourly patterns, it does not offer any improvements with respect to avoided capacity costs or with respect to geography and

[309] Johnson Direct, p. 29.
[310] *Id.*

weather fluctuations.[311]

NCSEA Witness Johnson recommended calculating separate rates for each hour of each month.[312] NCSEA Witness Johnson noted that sending granular price signals at this level would allow more precise alignment with monthly variations in hydro flows and the movement of the sun, as well monthly variations in the timing of when cloud coverage and rainstorms tend to occur.[313] Such a rate design would provide more precise price signals, which makes it possible to more precisely match QF revenues to avoided costs, and which can improve economic efficiency by helping QFs make better decisions with respect to the design, engineering and operation of their facilities.[314] In its reply comments, Duke agreed that time-of-day pricing periods could better align actual avoided costs to QF payments, but noted its belief that the pricing periods that it proposed in the instant proceeding are sufficient at this time.[315]

Real-Time Pricing

In addition to recommending more granular avoided energy rates, NCSEA Witness Johnson testified that implementing real time pricing during extreme conditions would send more precise price signals to QFs.[316] NCSEA Witness Johnson testified that utilizing real time pricing during a small number of hours when costs are unusually high or low would lead to more accurate avoided energy costs.[317]

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[311] *Id.* at pp. 29-30.
[312] *Id.* at p 30.
[313] *Id.* at p. 31.
[314] *Id.* at pp. 31-32.
[315] *Duke Reply Comments*, pp. 74-75.
[316] Johnson Direct, p. 32.
[317] *Id.* at pp. 32-33.

In response to NCSEA Witness Johnson's real-time pricing proposal, Duke agreed that real-time pricing would better align actual avoided costs to QF payments, but both Duke and Dominion expressed concern about the administrative burden of implementing such a paradigm at this time.[318] NCSEA Witness Johnson responds that such practical concerns suggest a need to move carefully, but do not provide a valid reason to reject NCSEA's proposal.[319]

DISCUSSION AND CONCLUSIONS

Granular Avoided Energy Rates

In its *Sub 148 Order*, the Commission directed the Utilities "to propose avoided cost rates in the next biennial avoided cost proceeding that reflect consideration of factors such as the availability of capacity, the QF's dispatchability and reliability, and the value of the QFs' energy and capacity, without regard to the technology the QF uses to generate electricity." One method of achieving the Commission's goal is to provide further granularity in avoided energy rates. As such, the Commission directs the Utilities to include the granular, 12x24 rate design recommended by NCSEA Witness Johnson as an option for QFs in their 2020 avoided cost filings.

Real-Time Pricing

As an initial matter, the Commission notes that no party disputes that real-time pricing would better align avoided cost rates with the Utilities' actual avoided costs. Duke's objections to NCSEA Witness Johnson's real-time pricing proposal are twofold: first, Duke asserts that they have provided sufficiently granular rate design proposals in the current

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[318] *Duke Reply Comments*, pp. 74-75. *Dominion Reply Comments*, p. 25.
[319] Johnson Direct, pp. 29-37

proceeding and, second, Duke asserts pragmatic concerns about issues such as metering. The Commission is not persuaded by either objection. First, while the rate designs proposed by Duke in the current proceeding are more granular than those approved in the *Sub 148 Order*, they can still be approved upon. Second, while Duke expressed practical concerns in the instant proceeding, it did not express practical concerns in the Green Source Advantage proceeding, where it entered into a stipulation, adopted by the Commission, that authorized near real-time pricing for use in that program.[320] As such, the Commission directs the Utilities to include a real-time avoided cost option, as described by NCSEA Witness Johnson, in their compliance filing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

SUMMARY OF THE EVIDENCE

In its *Sub 148 Order*, the Commission directed the Utilities to "file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer peak periods, with more granularity than the current Option A and Option B rate schedules."[321]

In its initial filings, Dominion explained that it has offered both Option A and Option B to QFs rates since the Sub 136 proceeding.[322] Dominion stated that all but one standard solar QF is currently selling to Dominion has chosen to sell at Option B rates, which is reasonable given the improved price signal that Option B provides to solar QFs.[323]

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[320] *See generally*, *Order Modifying and Approving Green Source Advantage Program, Requiring Compliance Filing, and Allowing Comments*, pp. 44-45, Docket Nos. E-2, Sub 1170 and E-7, Sub 1169 (February 1, 2019).
[321] *Sub 148 Order* at p. 56.
[322] *Dominion Initial Statement*, p. 27.
[323] *Id.*

Dominion asserted that it has proposed new rates schedule response to the Commission's directives in the *Sub 148 Order* that offer additional granularity and improve price signals to QFs.[324] Dominion's old rates included just two seasons—summer and non-summer—the proposed new rate design added a "shoulder season" that includes March, April, October, and November.[325] Dominion's new rate design also included afternoon hours on weekdays and weekends in its Energy Peak Hours, in recognition of the fact that higher energy prices can occur on both weekday and weekend days. Dominion's new Capacity Peak Hours included weekdays only, since the Company's historically observe system peak loads predominantly occurred on weekdays.[326]

In initial comments, NCSEA Witness Johnson argued that Dominion should not use the same energy rates across the summer, winter, and shoulder seasons and should not use the same on-peak hours in the winter and shoulder seasons.[327] Witness Johnson argued that this widespread averaging of costs obscures underlying cost patterns and weakens price signals.[328] Witness Johnson proposed that the Utilities calculate separate rates for each hour of each month or use three seasons, with each season having three rate periods corresponding to the time of day when energy is most needed.[329]

In its initial filings the Public Staff stated that Dominion's proposed changes to its on- and off-peak energy hour designations complied with the Commission's directive to

[324] *Id.* at p. 28.
[325] *Id.*
[326] *Id.* at p. 29.
[327] Johnson Affidavit, pp. 61-62.
[328] *Id.* at p. 63.
[329] *Id.* at pp. 64-66.

propose more granular rates.[330] The Public Staff also expressed support for Dominion's proposal of a shoulder season. However, the Public Staff also proposed additional refinements to Dominion's on- and off-peak hours designations through a three-step analysis that included a shoulder season and a "premium peak" designation, resulting in nine pricing sub-periods for energy.[331]

In its reply comments, Dominion agreed to accept the Public Staff's proposal, subject to some modifications.[332] One of these modifications was that the Public Staff agreed to include the month of September in Dominion's summer peak season.[333] Dominion asserted that the majority of NCSEA Witness Johnson's concerns should be addressed by Dominion's willingness to accept the Public Staff's proposal subject to some modifications.[334]

DISCUSSION AND CONCLUSION

The Commission agrees with the Public Staff and NCSEA that the rate design initially proposed by Dominion is overly simplistic and fails to offer the level of granularity that was sought by the Commission in its *Sub 148 Order*. The Commission notes that the granularity sought by NCSEA and the Public Staff, three seasons with three rate periods each, has now been agreed to by Dominion. As such, the Commission finds that, at this time, it is appropriate for Dominion to offer avoided cost rates that contain three seasons with three rate periods each.

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[330] *Public Staff's Initial Comments*, p. 48.
[331] *Id.* at p. 55-56.
[332] *Dominion Reply Comments*, pp. 23-24.
[333] *Id.*
[334] *Id.* at 25.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 32-41

SUMMARY OF THE EVIDENCE

In this proceeding Duke has proposed to make a number of modifications to its Schedule PP terms and conditions and PPAs. Duke originally proposed that any QF that requested to increase its "Contract Capacity" under the current Schedule PP PPA and Section 4 of the Terms and Conditions would not be allowed if the QF seeks to retain its pre-existing standard offer PPA. Duke stated that any such action by the QF would constitute a modification to the QF "Facility" that has committed to sell power to DEC or DEP under the then-effective PPA and an event of default resulting in termination of the PPA, at the Companies' election.[335] Duke proposed that a QF requesting to increase its "Contract Capacity" must enter a new PPA with DEC or DEP at its current avoided cost rates.[336] Duke also included a provision that required the QF to comply with all Duke "system operator instructions provided by the Company, including any energy storage protocols provided if applicable." Duke proposed a new provision that "[a]ny material modification to the Facility, including without limitation, a change in the AC or DC output capacity of the Facility or the addition of energy storage capability shall require the prior written consent of the Company, which may be withheld in the Company's sole discretion, and shall not be effective until memorialized in an amendment executed by the Company and the Seller." Duke characterizes these proposed changes to the standard offer PPA and Terms and Conditions as "clarifications."[337]

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[335] *Duke Initial Statement*, p. 35.
[336] *Id.* at p. 36.
[337] *Id.*

NCSEA stated in Initial Comments that the issue of material modification is squarely an interconnection issue, and "Duke has already agreed that changes to the DC capacity of a QF do not constitute a material modification for the purpose of interconnection."[338] NCSEA also stated that Duke's proposed definition of "material modification" was overly broad and discriminated against QFs. NCSEA also stated that the Commission should reject Duke's proposal regarding energy storage protocols because the Companies have not provided these storage protocols for Commission review and approval. NCSEA also opposed Duke's proposal to add the DC capacity of a QF to the definition of nameplate capacity and contract capacity and Duke's proposal to have unilateral authority to void a PPA if a QF increases its annual energy production above the estimate provided in the PPA.[339] NCSEA stated that the proposed change to nameplate capacity definition would have the effect of such a definition would be that a QF could not make any changes to a generation facility without the utility's approval. NCSEA argued that strictly limiting a QF to its estimated output ignores the fact that the estimate is just that, an estimate, ignores PURPA's requirement that a utility purchase all energy and capacity provided by a QF, ignores interconnection studies that assume QFs will generate at full capacity and would require a QF to lose its LEO if it re-powered by replacing existing solar panels during the PPA.

SACE argued that Duke's proposed energy storage provision would create financial uncertainty for QF-owned storage that will make financing storage projects difficult or

[338] *NCSEA's Initial Comments*, pp. 51-52.
[339] *Id.* at p. 53.

impossible because QFs intending to develop a project that incorporates battery storage will not know the conditions under which their storage facility may be subject to operational control by Duke's system operator.[340] SACE also argued that Duke's proposed changes regarding material modification to an existing QF are unnecessarily restrictive and should be rejected and that Duke's proposal would require an existing QF that repowers or adds storage to abandon its existing PPA and enter into a new PPA under the current avoided cost rates.[341]

The Public Staff noted in its Initial Statement that the term "material modification" is not defined in the PPA or Terms and Conditions and recommended that the term be defined.[342] Regarding the energy storage protocol proposal, the Public Staff noted that neither "system operator instructions" or "energy storage protocol" were defined and recommended that those terms should be defined for purposes of the standard offer contract and an example of an energy storage protocol should be incorporated into the contract. The Public Staff also recommended that the Commission direct DEC and DEP to amend their Terms and Conditions to provide additional clarity on these new requirements for market participants.[343] The Public Staff stated that requested changes to contract capacity and estimated energy production should not unreasonably be withheld, and the Public Staff does not support the utility being able to deny such a request in its sole discretion.[344]

In Duke's Reply Comments, the Companies added a defined term for "Material

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[340] *Initial Comments of SACE*, p. 15.
[341] *Id.* at p. 16.
[342] *Public Staff's Initial Comments*, pp. 77-78.
[343] *Id.* at p. 78.
[344] *Id.* at p. 80.

Alteration" "to more clearly define what constitutes a 'material change' to a QF that would trigger the utility's right to terminate the PPA if the utility's consent is not first obtained."[345] Duke's definition of "material alteration" excluded the "repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%)" and stated that the Companies would review changes to QFs "in a commercially reasonable manner."

In Direct Testimony, Duke Witness Johnson stated that Duke's proposed "material alteration" definition clarifies that QF owners may not modify the originally certificated Facility that entered into the PPA and has been selling power at the Companies' pre-existing avoided cost rates in such a way as to increase the Existing Capacity of the generating Facility or to reduce the Existing Capacity by more than 5%.[346] Witness Johnson also described the Companies' proposed storage protocols.

In Supplemental Testimony, Duke Witness Snider respond to the Commission's June 14, 2019 *Order Requiring Supplemental Testimony and Allowing Responsive Testimony* ("Order") requesting that the Utilities address the avoided cost rate schedule and contract terms and conditions that a QF proposing to add battery storage to its electric generating facility would receive. Witness Snider stated the Companies' position that a "committed" QF proposing to integrate battery storage should not be allowed to do so without the utility's consent (if a PPA exists) and, in all cases, should enter into a new or

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[345] *Duke Reply Comments*, p. 139.
[346] Duke Witness Johnson Direct, p. 8.

modified PPA at the Companies' then-current avoided cost rates.[347] Witness Snider stated that it would be "inequitable and inconsistent with PURPA to allow QFs that have obtained a CPCN and previously committed to sell output under Sub 136, Sub 140, or Sub 148 contracts to increase their capability to change their production output.[348] Witness Snider also stated that the Companies' proposed modifications to the standard terms and conditions addressing "material alterations" of QF generating facilities are intended to provide more clarity to QF owners and investors regarding the implications of proposals to integrate battery storage or to make other material changes to existing QFs.[349]

In Supplemental Testimony, Dominion Witness Billingsley stated that that in all three of the scenarios presented by the Commission (a QF that either (1) has established a LEO only, (2) executed a PPA, or (3) is currently operating, and is seeking to add battery storage to its facility), the avoided cost rates and terms within the current biennial period would apply to the entire facility. Witness Billingsley stated that the primary reason for this position was the risk of burdening the Dominion's customers with increased costs if existing QFs were allowed to install batteries and continue to receive stale, out of market avoided cost rates for the generation from the entire facility (i.e., the existing QF plus the battery).[350] Witness Billingsley concluded that the Company believes that allowing the existing solar generation facility to continue to receive the original rates for which it was eligible, while applying the current rates to the output from the battery addition, appears to

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[347] Snider Supplemental, p. 5.
[348] *Id*. at pp. 5-13.
[349] *Id*. at p. 13.
[350] Billingsley Supplemental, p. 2.

be a reasonable approach to the Commission's question.[351]

In Supplemental Testimony, Public Staff Witness Metz acknowledged that battery storage has the potential to be an important resource when paired with intermittent generation sources like solar.[352] that Duke's proposals relating to the addition of storage to committed QFs could frustrate the addition of battery storage, despite storage having the potential to provide system and retail customer benefits.[353] Witness Metz agreed that a QF seeking to add additional energy output to the grid as a result of added storage should be compensated for the additional energy at the most current avoided cost rates, but he did not agree with the utilities that a QF should lose its eligibility for the rates it established for the original output of the QF.[354] Witness Metz defined "additional energy" as "that energy produced by a generation source (in this case, the QF) and either provided to the grid or stored for future use in another medium (in this case, the battery) that is greater than the energy output of the stand-alone QF facility as designed and studied during the facility's original interconnection request, and that formed the basis for the original LEO."[355] Witness Metz discussed that re-paneling or over-paneling could increase the DC capacity of a QF without adding storage but noted that it was unclear whether this would be considered a material modification or a material alteration.[356] Witness Metz also described the interplay between the proposed definition of material alteration and the NC Interconnection Procedures and described potential engineering challenges of adding

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[351] *Id.* at p. 4.
[352] Metz Supplemental, pp. 2-3.
[353] *Id.* at p. 4.
[354] *Id.* at p. 5.
[355] *Id.* at p. 6.
[356] *Id.* at pp. 8-13.

storage.[357]

SACE Witness Glick testified that Duke's proposed modifications to its PPA and terms and conditions would actively discourage the addition of battery storage, a capacity resource that would add significant value to the system and that this outcome is undesirable for ratepayers and grants the utility unnecessary and unwarranted control over a QF.[358] Witness Glick concluded that (1) Duke Energy's proposal actively discourages the addition of battery storage, a capacity resource that would add significant value to the system and to ratepayers by firming up solar PV variability and allowing the shifting of output from solar QFs to further align with system peak; (2) the Companies' claim that allowing QFs to integrate battery storage will increase costs to customers is inaccurate and ignores the significant potential increased value to the system provided by storage; and (3) the proposed Energy Storage Protocol is imprecisely targeted at QF system sub-components, and it imposes a constant output requirement that could unnecessarily limit generation output during high demand, premium periods.[359]

NCSEA Witness Norris discussed the broad significance of market access for energy storage, reviewed the potential value of storage additions to committed generating facilities, particularly to the state's operating solar asset base, discussed the positions presented by Duke and Dominion with respect to adding storage to existing QFs, and provided a recommendation on how to approach the specific question posed by the Commission's Order.[360] Witness Norris stated that it is broadly recognized that energy

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[357] *Id.* at pp. 14-18.
[358] Glick Supplemental, pp. 3-4.
[359] *Id.* at p. 14.
[360] Norris Supplemental, pp. 5-6.

storage resources in general, and utility scale batteries in particular, will play an increasingly significant role in enabling a more affordable, reliable, and sustainable electricity system.[361] Witness Norris discussed H.B. 589's inclusion and results of an energy storage study requirement in North Carolina, including a discussion of the values and applications of storage presented in the 2018 NC State storage study.[362] Witness Norris also discussed the evaluation of storage in other jurisdictions, including at FERC with respect to the utilization of storage in ISOs/RTOs.[363] Witness Norris stated that it is incumbent upon this Commission to make decisive regulatory interventions to remove barriers to market entry for energy storage, in the context of this proceeding and beyond, including the immediate need to remove barriers to the addition of storage to existing QFs.

Witness Norris emphasized the need for QFs to be able to make reasonable and beneficial changes and updates to its facility, including the addition of storage, without being forced to abandon their existing PPAs, and that Duke's proposed changes to the PPA are not supported by the testimony of Duke witnesses.[364] Witness Norris emphasized that although it is his position that the existing PPAs allow a QF to add storage at the existing avoided cost rate without abandoning its PPA, NCSEA would be willing to offer a compromise position in which, if a QF seeks to add energy storage to a committed generating facility, and if that storage addition is approved via the interconnection standard, the output from that storage equipment would be eligible for the then-available avoided cost rate schedule.[365] Witness Norris emphasized that the storage facility would not be a

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[361] *Id.* at p. 7.
[362] *Id.*
[363] *Id.* at p. 8.
[364] *Id.* at 12-26.
[365] *Id.* at p. 27.

new QF but would constitute an equipment change accompanied by a revision to the PPA, with the PPA revision limited to the accommodation of the storage equipment. The revised PPA would maintain the remainder of the original PPA's terms and conditions, including the remaining PPA tenor. The remaining PPA tenor would be available to the output of the facility's existing generation equipment and to the additional storage equipment. This would apply to QFs that have executed a PPA or commenced operation. In the scenario of a QF that has established a LEO but has not executed a PPA, the same PPA treatment would apply: if that QF seeks to add storage as approve via the interconnection standard, the QF's storage equipment would be eligible for the then-current avoided cost rate schedule, for a PPA tenor equivalent to the avoided cost rate schedule of its original LEO.[366]

Witness Norris recommended that to implement this approach the Commission could order that existing standard offer QF PPAs and negotiated QF PPAs shall be modified to incorporate storage upon election by an interconnection customer, with the storage equipment's output subject to the most recent Commission approved avoided cost rate schedule. For storage additions to standard offer QF PPAs, the Commission would approve standard storage PPA language. For negotiated QF PPAs, commercially reasonable terms and conditions would be negotiated.[367] Witness Norris also stated that the rate available to the output of the storage facility should be set, at minimum, to the 10-year avoided cost rate (assuming at least 10 years of the QF's PPA schedule remains) which

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[366] *Id.* at pp. 27-29.
[367] *Id.* at pp. 28-29.

would provide the QF a reasonable opportunity to attract private capital to finance a storage addition.[368]

DISCUSSION AND CONCLUSION

The Commission begins by addressing Duke's claim that existing QF PPAs under prior vintage contracts including under Sub 136, Sub 140, and Sub 148 should be read to include the changes to the Schedule PP terms and conditions and PPA that Duke now proposes to make prospectively. Duke has characterized its proposed changes to the PPA and terms and conditions as "clarifying" in nature. However, the Commission notes that the meaning and effect of existing PPAs turns on the plan language of those documents, or an interpretation of any ambiguity by this Commission or the courts. The Commission has reviewed its approved PPA documents from the E-100 Sub 136, Sub 140, and Sub 148 proceedings and concludes that the documents that comprise the Sub 136 and Sub 140 PPAs do not impose the limitations on QFs that Duke has asked the Commission to make in Duke's form PPA and Terms and Conditions going forward. The existing PPA documents do not require a QF to obtain the permission of the utility prior to adding a storage facility or making other equipment modifications. The modifications Duke has proposed constitute major substantive changes to the respective rights and obligations of Duke and QFs relative to the terms of prior standard offer contract documents. As such, the Commission rejects Duke's characterization of these changes as clarifying in nature and declines to adopt or impose these new and altered terms on QFs retroactively.

The Commission finds that many of Duke's proposed modifications to the Form

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[368] *Id*. at p. 30.

PPA and Terms and Conditions should be modified or rejected. These changes seek (1) to redefine the "Nameplate Capacity" of the Facility to include its DC rating (as well as AC capacity), (2) to create a new defined term ("Existing Capacity") equal to the Facility's "estimated annual energy production" stated in the PPA, (3) to prohibit a "Material Alteration" to the Facility without Duke's consent, with "Material Alteration defined to include (a) the addition of a Storage Resource, (b) an increase in the AC capacity or DC rating of the Facility, (c) an increase to the Existing Capacity of the Facility[369], and (d) a decrease in Existing Capacity by more than 5%. The effect of these changes would be to require any QF seeking to modify its Contract Capacity or Nameplate Capacity (including its DC rating), to increase its annual energy production above an estimated value, or to add storage to enter into a new PPA at current avoided cost rates.

The Commission finds that although Duke's terms and conditions provide that a QF's AC Contract Capacity may not be modified without the Company's consent or exceeded without an amendment to the PPA, the terms and conditions do not support or allow prohibiting changes in the QF's DC rating and limiting efficiency improvements in the QF. Any necessary limitation on a QF increasing its energy output at a given AC capacity can be achieved by a clear maximum annual energy production value that may not be exceeded without a PPA amendment or Duke's consent. The Commission finds that Duke's proposed limitation on changes to a QF's DC rating, including the proposed definition of "Nameplate Capacity" and the corresponding portion of the proposed

[369] As originally presented by Duke, the definition of "Material Alteration" could have been read to allow an increase of 5% or less to Existing Capacity due to the like-kind repair or replacement of equipment, but the Public Staff has proposed, and Duke has accepted, a repunctuation of the definition that eliminates that reading. *See* Metz Supplemental at 11 and fn. 22; Duke Joint Supplemental Rebuttal at 32-33.

"Material Alteration" definition should be deleted in their entirety.

Next, the Commission accepts the inclusion of a maximum annual energy production value in the Sub 158 PPA and Terms and Conditions but modifies Duke's proposal as follows. Any maximum not-to-exceed level of annual energy production must be stated as a maximum, not an estimate, and the maximum energy production will be calculated as follows: [Nameplate Capacity(AC) x 8760 x .30] x 1.10. This formula appropriately balances the need to provide QFs with a reasonable amount of operating flexibility without unlimited ability to increase their output at existing PPA rates. Consistent with the above, the Commissions rejects Duke's proposed definition of "Existing Capacity."

The Commission also finds that Duke's proposal to prohibit more than a 5% reduction in annual energy production to be unrelated to Duke's stated objective of ensuring that it not be required to purchase additional energy at stale rates and departs from the Commission's long-standing position of not imposing a minimum annual energy production value in standard offer PPAs. As such, the Commission rejects this element of the proposed "Material Alteration" definition. Any concerns about technical or operational impacts of equipment modifications are appropriately addressed under the Commission's Interconnection Procedures and the parties' respective interconnection agreement.

The Commission finds that prior Dominion standard offer PPAs also do not contain a limit on DC capacity or annual energy output and do not prohibit or require Dominion's approval for modifications to the QF facility or shifting the time of energy delivery. The Commission does not agree with Dominion Witness Billingsley that the addition of storage to QFs that have formed LEOS, executed standard offer PPAs, or are in operation, is prohibited, as well as increases in energy production and time-shifting of energy output. Witness Billingsley acknowledges that Dominion's prior standard offer tariffs and PPAs do not specifically address the issue of storage additions, and Dominion's Sub 136 and Sub 140 standard offer tariffs and PPAs do not support Witness Billingsley's position. The Commission also rejects Dominion's argument that modifications to facility equipment or output should not be allowed to the extent that those matters were addressed in the QF's Form 556 or CPCN. The Commission notes that facility information contained in those filings is routinely subject to changes, and nothing in the PPAs prohibit or require Dominion approval for modifications to those documents or to the underlying facility characteristics that may be described in them. Therefore, Dominion's Sub 136 and Sub 140 PPAs do not limit storage additions or the other types of facility modifications that the Commission has described above with respect to Duke.

The Commission finds that the compromise position presented by NCSEA and NCCEBA with respect to the addition of storage resources to an existing QF reasonably balances the interests of parties to this proceeding and represents sound public policy. Therefore, the Commission adopts the proposal that the output of any storage additions to committed QFs (i.e. those with enforceable LEOs or executed PPAs) be compensated at the avoided cost rate in effect when the QF's interconnection agreement is amended to include the storage addition. The new avoided cost rate for the storage addition shall be calculated and available for the remaining life of the QF's current PPA, and the PPA price paid for the rest of the output of the QF will be unchanged and unaffected. This position is consistent with the testimony of NCSEA Witness Norris and is similar to the position taken by Public Staff Witness Metz. The Commission also agrees with Ecoplexus Witness

Wallace that it is technically feasible to separately meter storage additions to solar facilities. The Commission rejects the inclusion of "the addition of a Storage resource" in the definition of "Material Alteration."

The Commission also finds that it is good public policy to support the advancement of battery storage technologies in North Carolina, consistent with the testimony of NCSEA Witness Norris, Public Staff Witness Metz, SACE Witness Glick, and Ecoplexus Witness Wallace. Storage resources offer numerous benefits, including the potential to mitigate the impacts of solar intermittency and to allow energy to be delivered when it is most needed.

Finally, Duke has proposed a new Energy Storage Protocol as Exhibit A to its form Standard Offer PPA, the details and merits of which have not been addressed in this proceeding. On the other hand, a similar proposed protocol has been the subject of detailed discussions among stakeholders in connection with the CPRE PPA, which are ongoing. The Commission will not approve an energy storage protocol for the standard offer program until the issue has been resolved under CPRE and the Commission can consider the results of those negotiations.

IT IS, THEREFORE, ORDERED as follows:

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

2. DEC and DEP shall recalculate their avoided energy costs as follows:

a) DEC and DEP shall recalculate the fuel price forecasts using uses 18 months of natural gas forward pricing, 18 months of blending natural gas forward pricing, and ICF pricing beyond 26 months to calculate avoided energy costs.

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

3. DENC shall recalculate its avoided energy costs as follows:

a) DENC shall either (i) reinstate the historical 3% line loss adder or (ii) calculate and instate a line loss adder that accurately reflects the line loss avoidance benefits provided by solar QFs in DENC territory based on a reasonable and transparent methodology.

4. DEC, DEP, and DENC shall recalculate their avoided capacity costs as follows:

a) DEC, DEP, and DENC shall recalculate their avoided capacity costs based on revised demand response assumptions which allocate demand response resources in accordance with identified resource adequacy risk.

b) DEC, DEP, and DENC shall recalculate their PAF calculations to include June, September, and December, and March to account for QF capacity contributions during these months.

5. DEC and DEP shall recalculate their avoided capacity costs as follows:

a) DEC and DEP shall recalculate their avoided capacity costs to comply with the Commission's *Sub 140 Order*, which requires DEC and DEP to use seasonal allocation weightings of 60% winter and 40% summer in most cases.

b) Pending a Commission order following the January 8, 2020 oral argument in the 2018 IRP Docket, E-100, Sub 157, to resolve issues around Duke's reserve margin and load forecasts, DEC and DEP will propose new seasonal capacity allocations that conform to that order.

6. In developing future resource adequacy studies, DEC and DEP shall:

a) Study the relationship between extreme cold conditions and load, taking into account relevant factors such as likely facility closures and the impact of wind speeds.

b) Research the drivers of sharp winter load spikes under extreme cold conditions and develop programs for shaving these rare and brief spikes.

c) Research the potential for load forecast errors due to economic and demographic forecast errors.

d) Provide all model reports and a comprehensive set of sensitivity analyses with all future resource adequacy and related studies.

7. For any integration charges or redispatch charges proposed in future proceedings, DEC, DEP, and DENC shall propose a plan for assembling a technical review committee ("TRC"), or in alternative a third-party expert review process to determine whether the following issues should be included as part of a comprehensive study quantifying the costs and benefits of solar integration to be reviewed by the Commission at the next biennial avoided cost proceeding:

a) Whether the $LOLE_{FLEX}$ metric is an appropriate metric for real-time operational reliability;

b) How to appropriately model scaling of short-term solar variability;

c) Whether deployment of demand-side technologies could more efficiently resolve the impacts of solar volatility on net load;

d) Whether it would be appropriate to consider DEC, DEP, and DENC's entry in an energy imbalance market or other market structure;

e) How to quantify the benefits associated with addition of solar QFs to the DEC, DEP, and DENC systems (e.g. avoided transmission and distribution costs, lower market prices, deferred environmental benefits, ancillary services from solar QFs with co-located battery storage).

f) Whether investing in fast-start flexible resources such as batteries would more economically and efficiently mitigate DEC, DEP, and DENC's concerns regarding five-minute ramping shortfalls;

g) Whether operational or contractual solutions could be used to remedy the impacts of low occurrence events that contribute to proportionally higher integration costs, and how these solutions could mitigate these events and reduced integration costs and charges.

8. DEP and DEC will not implement an energy storage protocol for the standard offer program until the issue has been resolved under CPRE and the Commission can consider the results of those negotiations.

9. DEP, DEC, and DENC will adopt the compromise position presented by NCSEA and NCCEBA with respect to the addition of storage resources to an existing QF, including the following provisions:

a. The output of any storage additions to committed QFs (i.e. those with enforceable LEOs or executed PPAs) will be compensated at the avoided cost rate in effect when the QF's interconnection agreement is amended to include the storage addition; and

b. The new avoided cost rate for the storage addition shall be calculated and available for the remaining life of the QF's current PPA, and the PPA price will be paid for the rest of the output of the QF will be unchanged and unaffected.

10. DEP and DEC will not retroactively impose its proposed modifications to the standard offer PPA and terms and conditions on QFs. DEP and DEC will do the following with respect to their proposed modifications of the contract terms and conditions:

a. Remove the proposed limitation on changes to a QF's DC rating, including the proposed definition of "Nameplate Capacity" and the corresponding portion of the proposed "Material Alteration";

b. Adopt the maximum annual energy production value as proposed and modified by NCSEA and NCCEBA;

c. Remove the proposed definition of "Existing Capacity";

d. Remove the proposed prohibition on more than a 5% reduction in annual energy production from the definition of "Material Alteration"; and

e. Remove the proposed prohibition of the addition of storage in the definition of "Material Alteration."

11. The Utilities will include a Statement of Need in future IRPs that clearly describes how the Utilities have determined their respective capacity needs that will be used to establish the respective capacity need applied to avoided cost rates. The Statement of Need will include a description of QFs that have committed to renew their PURPA contracts with the Utilities.

12. Within 180 days of this order, the Public Staff shall file an update on discussions between the parties regarding the status of stakeholder discussions regarding notice from QFs that have expiring PPAs that they will continue to provide energy and capacity to the Utilities, such as any additional terms that would need to be addressed, including any appropriate penalty for a QF that committed to renew its contract and failed to do so.

13. The Public Staff shall convene stakeholders having an interest in market price suppression caused by QFs and file a report with the Commission within 180 days regarding the status of discussions

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of __________, 2019.

NORTH CAROLINA UTILITIES COMMISSION

Janice Fulmore, Deputy Clerk