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June 22, 2017

VIA ELECTRONIC FILING

Ms. M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
Dobbs Building
430 North Salisbury Street
Raleigh, North Carolina 27603

Re: Docket No. E-100, Sub 148

Dear Ms. Jarvis:

Enclosed for filing in the above-referenced docket is the *Proposed Order of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina*. A copy is also being provided via electronic mail to briefs@ncuc.net.

Should you have any questions, please do not hesitate to contact me. Thank you for your assistance with this matter.

Very truly yours,

/s/Andrea R. Kells

ARK:kjg

Enclosure

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	PROPOSED ORDER OF
Rates for Electric Utility Purchases from	)	VIRGINIA ELECTRIC AND
Qualifying Facilities – 2016	)	POWER COMPANY, D/B/A
	)	DOMINION ENERGY NORTH
	)	CAROLINA

HEARD: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on February 21, 2017, at 9:00 am and on April 18-21, 2017, at 9:30 am.

BEFORE: Chairman Edward S. Finley, Jr., Presiding
Commissioner Bryan E. Beatty
Commissioner ToNola D. Brown-Bland
Commissioner Don M. Bailey
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Lyons Gray

APPEARANCES:

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

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

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

With respect to electric utilities subject to state regulation, FERC delegated the implementation of these rules to the 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.

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

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

On June 22, 2016, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing in the instant proceeding (Scheduling Order). The Scheduling Order made Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP) (together, Duke), Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (Dominion Energy North Carolina[1] and, together with DEC and DEP, the Utilities), Western Carolina University (WCU), and New River Power and Light Company (New River) (collectively, the Utilities) parties to the proceeding in order to establish the avoided cost rates each is to pay for power purchased from QFs pursuant to Section 210 of PURPA and the associated FERC regulations and G.S. 62-156. The Scheduling Order also stated that the Commission

[1] Effective May 10, 2017, Dominion Resources, Inc., Virginia Electric and Power Company's publicly held parent company, changed its name to Dominion Energy, Inc. As part of this corporate-wide rebranding effort, Virginia Electric and Power Company has changed its "doing business as" ("d/b/a") names in Virginia and North Carolina effective May 12, 2017. In Virginia, Virginia Electric and Power Company's d/b/a name has been changed from Dominion Virginia Power to Dominion Energy Virginia, and in North Carolina the d/b/a name has been changed from Dominion North Carolina Power to Dominion Energy North Carolina. The legal corporate entity name "Virginia Electric and Power Company" will not be changing as a result of this rebranding effort.

would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits, and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits, and schedules, rather than a full evidentiary hearing for the purpose of receiving expert testimony.

The Scheduling Order also required that DEC, DEP, Dominion Energy North Carolina, WCU, and New River file the statements and exhibits specified in the Scheduling Order on or before November 1, 2016. The Scheduling Order also requested that other persons desiring to become formal parties to the proceeding petition the Commission for leave to intervene and file with the Commission the comments and exhibits they wished to present on or before January 9, 2017.

The Scheduling Order also directed that the electric utilities and intervenors could file reply comments on or before February 15, 2017, and that parties were requested to file proposed orders on or before March 15, 2017. A public hearing solely for the purpose of taking non-expert public witness testimony was scheduled for February 21, 2017.

The North Carolina Sustainable Energy Association (NCSEA), Carolina Utility Customers Association, Inc. (CUCA), the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR), the Public Works Commission of the City of Fayetteville, the Southern Alliance for Clean Energy (SACE), North Carolina Electric Membership Corporation (NCEMC), NTE Carolinas Solar, LLC (NTE), Strata Solar, LLC (Strata), the North Carolina Pork Council (Pork Council), Cypress Creek Renewables, LLC (Cypress Creek), and O2 EMC, LLC (O2) filed petitions to intervene, all of which were granted by the Commission. The Public Staff's intervention and participation in this proceeding is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). Pursuant to G.S. 62-20, the North Carolina Attorney General's office gave notice of intervention on April 11, 2017.

On October 21, 2016, DEC, DEP, and Dominion Energy North Carolina filed a Joint Motion for Extension of Time to file proposed avoided cost rates and standard form contracts. The Commission issued an order granting the motion for extension of time on October 27, 2017.

On November 15, 2016, Dominion Energy North Carolina filed Initial Comments and Exhibits along with avoided cost information as required by 18 C.F.R. 292.302(b)(1)-(3). Also on November 15, 2016, DEC and DEP filed a Joint Initial Statement and Exhibits. On December 16, 2016, Dominion Energy North Carolina filed corrected pages to its avoided cost information.

On November 28, 2016, WCU and New River filed joint proposed rates.

On December 20, 2016, NCSEA filed a Motion to Strike as irrelevant to the proceeding certain materials submitted in the proposals of DEC, DEP, and Dominion Energy North Carolina. On January 4, 2017, Dominion Energy North Carolina, DEC, and DEP filed responses in opposition to NCSEA's Motion to Strike. An order denying NCSEA's motion was subsequently issued on January 18, 2017.

On December 22, 2016, the Public Staff filed a Motion for Amended Procedural Schedule to allow the Public Staff and intervenors to conduct discovery on the testimony and to prepare responsive testimony. The Public Staff's Motion also included a request for an evidentiary hearing. On December 30, 2016, the Commission issued an Order

Scheduling Evidentiary Hearing and Amending Procedural Schedule (Procedural Order) which set a deadline for intervenors to file direct testimony and exhibits, set a deadline for the Utilities to file rebuttal testimony, and scheduled an evidentiary hearing for April 18, 2017.

Om January 17, 2017, DEC and DEP filed avoided cost information as required by 18 C.F.R. 292.302(b)(1)-(3).

On or before February 15, 2017, all electric utility companies filed Affidavits of Publication of Notice of Hearing, and the public hearing was held on February 21, 2017, as scheduled. Public witnesses Debbie Beroth, Amos Edison Speas, Jr., Harvey Richmond, Dave Rogers, Mara Frank, Lauren Englum, John Delafield, James Michael McManus, Martha Girolami, Maple Osterbrink, Martha Clemons, and TJ Hawley gave testimony at the public hearing. In addition, over 1,000 consumer statements of position were filed in this docket.

On February 21, 2017, Dominion Energy North Carolina filed the direct testimony and exhibits of J. Scott Gaskill and Bruce E. Petrie. Also on February 21, DEC and DEP filed the testimony and exhibits of Lloyd Yates, Kendal Bowman, Glen Snider, John Holeman, and Gary Freeman.

On March 22, 2017, NCSEA filed a Motion for Extensions of Time, requesting that the Commission extend the deadlines for direct and rebuttal testimony. On March 23, 2017, the Commission issued an order granting NCSEA's requested extensions.

On March 28, 2017, NCSEA filed the testimony and exhibits of Carson Harkrader, Ben Johnson, and Kurt Strunk; Cypress Creek filed the testimony of Patrick McConnell; and SACE filed the testimony and exhibits of Thomas Vitolo, Ph.D. On the same date, NCEMC filed initial comments. The Public Staff filed direct testimony and exhibits of John Hinton, Jay Lucas, and Dustin Metz.

On April 6, 2017, DEC and DEP filed a Joint Motion for Extension of Time to file rebuttal testimony which was granted by Commission order on April 6, 2017.

On April 7, 2017, Dominion Energy North Carolina filed a Motion for Limited Practice for Bernard L. McNamee which was granted by April 14, 2017 Commission order.[2]

On April 10, 2017, Dominion Energy North Carolina filed the rebuttal testimony of witnesses J. Scott Gaskill and Bruce E. Petrie, and DEP and DEC filed the rebuttal testimony of witnesses Kendal Bowman, Glen Snider, John Holeman, and Gary Freeman.

On April 11, 2017, the Commission issued an Order Requiring Filing of List of Witnesses and Estimated Time for Cross Examination. On April 13, 2017, DEP and DEC filed an Order of witnesses, Estimates of Cross-Examination Times, and Witness List.

The evidentiary hearing was held as scheduled on April 18, 2017, through April 21, 2017. DEC and DEP presented the testimony of witnesses Yates, Bowman, Snider, Holeman, and Freeman. Dominion Energy North Carolina presented the testimony of witnesses Gaskill and Petrie. Cypress Creek presented the testimony of witness McConnell. NCSEA presented the testimony of witnesses Harkrader, Strunk, and Johnson. SACE presented the testimony of witness Vitolo. The Public Staff presented the testimony of witnesses Hinton, Lucas, and Metz. The pre-filed testimony of those

[2] On May 2, 2017, Dominion Energy North Carolina filed a notice of withdrawal of Mr. McNamee from participation in this proceeding.

witnesses who testified at the evidentiary hearing, as well as all other witnesses filing testimony in this docket, was copied into the record as if given orally from the stand.

Proposed orders were filed by the parties on June 22, 2017.

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

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

FINDINGS OF FACT

1. Given the significant growth in solar QF development in this State in recent years, it is reasonable, appropriate, and consistent with this Commission's authority under FERC regulations to modify several aspects of the PURPA implementation in North Carolina, in order to restrike the balance this Commission seeks to achieve between encouraging QF development and protecting utility customers from the risk of overpayments.

2. The implementation of PURPA in North Carolina has resulted in the Utilities and their customers becoming committed to significant above-market payments to QFs eligible for rates established under the previous two biennial periods.

3. It is reasonable and appropriate to reduce the upper limit on a QF's size eligibility for standard rates and contract terms from 5 MW to 1 MW. Consistent with this change, Dominion Energy North Carolina should be required to offer standard long-term levelized rates and contract terms to all QFs contracting to sell 1 MW or less capacity.

4. It is reasonable and appropriate to reduce the maximum term that must be offered to QFs that qualify for standard offer rates and terms from 15 years to 10 years. Consistent with this change, Dominion Energy North Carolina should be required to offer long-term levelized rates and contract terms for 5-year and 10-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 1 MW or less, and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass QFs contracting to sell 1 MW or less. The standard levelized rate option of 10 years should include a condition making contracts under that option renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration. Dominion Energy North Carolina should be required to offer the standard 5-year levelized rate option to all other QFs contracting to sell 1 MW or less capacity.

5. Dominion Energy North Carolina should continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM Interconnection, LLC (PJM), subject to the same conditions as approved in the Commission's Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in the 2006 biennial avoided cost proceeding in Docket No. E-100, Sub 106 (Sub 106 Order). For consistency with the locational value of energy delivered by North Carolina QFs (as described further within this Order), Dominion Energy North Carolina

should revise its Schedule 19-LMP such that the energy price that it will pay pursuant to that rate schedule is the LMP at the PJM-defined nodal location nearest to where the energy is delivered.

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

7. The input assumptions used by Dominion Energy North Carolina for the purpose of determining its proposed avoided energy rates, including the avoided costs

related to fuel hedging activities, are reasonable and appropriate for use in this proceeding.

8. It is not appropriate to calculate off-peak avoided energy rates for solar QFs at this time.

9. It is reasonable and appropriate for Dominion Energy North Carolina to adjust its avoided energy rates to account for the locational value of distributed generation located in its North Carolina service area.

10. It is reasonable and appropriate for Dominion Energy North Carolina to eliminate the line loss adder from the avoided energy rates provided in its standard offer rate schedules.

11. Dominion Energy North Carolina does not have a near-term need for capacity, and additional distributed QF generation in its North Carolina service area will not permit Dominion Energy North Carolina to defer or avoid the need for capacity on its system. It is therefore reasonable and appropriate that Dominion Energy North Carolina not provide any avoided capacity credit during the term of standard offer contracts entered into under this proceeding.

12. To the extent a utility is required pursuant to this Order to provide a capacity credit at any time during the term of standard offer contracts entered into under this proceeding, the performance adjustment factor (PAF) used to calculate such avoided capacity rates should be 1.05.

13. Duke's proposal to continue to use a modified Notice of Commitment Form for the purpose of determining the legally enforceable obligation (LEO) date for small QFs that qualify for the Utilities' respective standard offers is reasonable and

appropriate and should be accepted. Duke's proposal to use the contracting procedures and Notice of Intent to Negotiate Form to determine the LEO date for large QFs that do not qualify for the standard offer is also reasonable and appropriate and should be accepted, subject to input from the Public Staff, Dominion Energy North Carolina, and other interested parties.

14. The rate schedules and standard contract terms and conditions proposed in this proceeding by Dominion Energy North Carolina are approved, except as otherwise discussed herein. Dominion Energy North Carolina should be required to file new versions of its rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence for this finding is found in Dominion Energy North Carolina's Initial Filing and in the testimony of Dominion Energy North Carolina witness Gaskill, Duke witness Bowman, Public Staff witness Hinton, and NCSEA witness Johnson.

Dominion Energy North Carolina's Initial Filing and Dominion Energy North Carolina witness Gaskill's direct testimony described the significant influx of solar QF development that has occurred in Dominion Energy North Carolina's North Carolina service area since the previous biennial avoided cost proceeding in Docket No. E-100, Sub 140 (2014 biennial proceeding). Witness Gaskill testified that when the previous avoided cost case commenced in February 2014, Dominion Energy North Carolina had only seven PPAs executed in its North Carolina service area for approximately 58 MW of solar QF capacity, and only one of those PPAs concerned a project that was operational. In contrast, as of February 1, 2017, Dominion Energy North Carolina had 72 effective PPAs for approximately 500 MW of solar QF capacity in North Carolina, including 9 PPAs totaling 45 MW that were executed just since its November 15, 2016 Initial Filing. Of that 500 MW, approximately 350 MW had commenced commercial operations, with 150 MW in development. Witness Gaskill presented data showing that, from an interconnection perspective, there were approximately 1,000 MW of capacity in Dominion Energy North Carolina's North Carolina distribution queue, and another 1,800 MW in the PJM queue for transmission level Dominion Energy North Carolina service area interconnections. He also emphasized that the vast majority of QFs with LEOs, with which Dominion Energy North Carolina is obligated to execute PPAs, qualify for the standard contract or negotiated avoided cost rates under the 2014 biennial proceeding. (T. Vol. 5 at 133-135)

Witness Gaskill also testified that, because the average on-peak load of its North Carolina service area during 2015 was approximately 518 MW, the amount of North Carolina distributed solar generation that is either already operational or under construction when viewed from the interconnection queue perspective, or under contract when viewed from the PPA perspective, already equals or exceeds Dominion Energy North Carolina's average on-peak load requirements. He noted that the total distributed solar capacity planned for Dominion Energy North Carolina's North Carolina system rises to approximately 680 MW when QFs that have established LEOs, but not executed PPAs, are included, which exceeds the average on-peak load requirements by approximately 160 MW. He noted further that when the capacity of projects with certificates of public convenience and necessity (CPCNs), but no LEOs, is accounted for, the total planned capacity increases dramatically to over 1,500 MW, almost three times Dominion Energy North Carolina's on-peak load requirements. (T. Vol. 5 at 138-139) Witness Gaskill also noted that Dominion Energy North Carolina's service area anticipates little load growth. (T. Vol. 5 at 140)

Witness Gaskill explained that three areas of avoided costs are impacted when distributed solar generation exceeds load: distribution line losses are not avoided; locational marginal prices (LMPs) are lower; and incremental QF generation cannot defer or avoid future capacity needs because there is no further load to offset. (T. Vol. 5 at 140) He testified that the modifications to the standard offer rates and terms to be determined in this case Dominion Energy North Carolina has proposed are intended to address these impacts of the influx of distributed solar development, while remaining consistent with the requirements of PURPA and FERC's rules. (T. Vol. 5 at 140) He stated that, while the Commission addressed similar proposals to some of these modifications in previous avoided cost proceedings, in light of the significant growth in solar QF development that has occurred since the 2014 biennial proceeding, it is imperative that the Commission reconsider these issues on a prospective basis for new solar QFs, or Dominion Energy North Carolina and its customers will be forced to overpay for new QF output in contravention of PURPA's intent. He noted the Commission statement from this docket that it has always established avoided cost rates and implemented PURPA in light of the then prevailing economic conditions facing public utilities and QFs and whether changed conditions justify changes in avoided cost rates and/or PURPA implementation. (T. Vol. 5 at 134)

Duke witness Bowman testified to the impacts to Duke's system and customer obligations due to the significant influx of solar QF development on DEC's and DEP's service areas. Witness Bowman explained that, while North Carolina's PURPA policies have remained relatively unchanged over the past decade, economic and regulatory circumstances—both in North Carolina and around the country—have changed dramatically, such that changes need to be made to continue to develop this energy landscape in a more sustainable manner. (T. Vol. 2 at 318-320)

Public Staff witness Hinton testified that the number and capacity of QF facilities that have been constructed or are under development in North Carolina over the past five years has been tremendous, with a large percentage of those projects developed at or near the 5 MW threshold. He specifically noted Dominion Energy North Carolina witness Gaskill's testimony that in total, there are approximately 2,800 MW of solar projects operating or in the interconnection process, as compared with Dominion Energy North Carolina's average on-peak load in North Carolina of 518 MW. Witness Hinton explained that, in addition to exceeding load growth experienced by the Utilities, the higher penetration of resources poses operational and technical challenges for the Utilities in meeting their obligation to provide safe, reliable, and economic service. (T. Vol. 8 at 21-23)

DISCUSSION AND CONCLUSIONS

This Commission has consistently concluded in prior avoided cost proceedings that we must reconsider the availability of long-term levelized rate options as economic circumstances change from one biennial proceeding to the next, balancing the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other.[3] This balance must also be struck with regard to other aspects of avoided cost determination and other practices regarding utilities' purchases of energy and capacity from QFs. In this proceeding, we have stated that "the nature of these recurring, biennial proceedings has always required consideration of current economic conditions facing public utilities and QFs and whether changed conditions justify changes in avoided cost rates and/or PURPA implementation."[4] This periodic reevaluation is consistent with our authority under FERC's regulations implementing PURPA, which delegate to this Commission the responsibility for determining each utility's avoided costs with respect to rates for purchases from QFs and, together with G.S. 62-156, authorize this Commission to implement PURPA in this State in a manner reasonably designed to give effect to FERC's rules.

In the 2014 biennial proceeding, the Commission concluded, for the most part, that its decisions in past proceedings continued to strike an appropriate balance between QF encouragement and customer protection, and that the same approach to determining eligibility for standard offer avoided cost rates and terms, and the same method for determining appropriate avoided cost rates, continued to be appropriate.

Based on the evidence in this proceeding, the Commission concludes that the balance between QF encouragement and customer protection that our previous decisions achieved is no longer being realized, and that it is appropriate, and consistent with our

[3] *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 9-10, Docket No. E-100, Sub 140 (Dec. 17, 2015) (Phase 2 Order); *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2012*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 11, Docket No. E-100, Sub 136 (Feb. 21, 2014).

[4] *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016*, Order Denying Motion at 3-4, Docket No. E-100, Sub 148 (Jan. 18, 2017) ("Order Denying Motion").

authority under PURPA and FERC's regulations, that we re-evaluate our current policies with regard to the parameters of the standard avoided cost offer and the calculation of related avoided cost rates. The evidence in this case demonstrates that tremendous growth in solar QF development has occurred in this State even since the 2014 biennial proceeding. It also clearly demonstrates that Dominion Energy North Carolina is currently obligated under executed PPAs to purchase 521 MW of solar capacity, which exceeds Dominion Energy North Carolina's average on-peak load in North Carolina of 518 MW. We believe that, given the number of QFs with LEOs and CPCNs located in Dominion Energy North Carolina's service area, and the expected slowing load growth anticipated for that area, this over-supply is likely to increase with time. Given this tremendous QF growth and increasing imbalance between installed solar capacity and utility load requirements, our interest in encouraging QF development while also protecting customers requires that we adjust our PURPA implementation practices as discussed in this Order to reestablish the balance between these two concerns.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence for this finding is found in the testimony of Dominion Energy North Carolina witnesses Gaskill and Petrie, and the testimony of Duke witnesses Bowman and Snider, Public Staff witness Hinton, and NCSEA witness Johnson.

In his direct testimony, Dominion Energy North Carolina witness Gaskill explained that, consistent with PURPA, the purpose of these biennial avoided cost proceedings is for the Commission to determine each utility's avoided cost. In addition, through these proceedings the Commission meets its obligation under FERC regulations to establish standard rates for small QFs, defined by FERC as those with capacity of 100 kW or less. He noted that FERC defines avoided costs as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from a QF, the utility would generate itself or purchase from another source. He noted further that both PURPA and FERC's rules require that avoided cost rates be just and reasonable to utility customers, in the public interest, and non-discriminatory to QFs. He emphasized that neither PURPA nor FERC require a utility to pay QFs more than its avoided cost in order to encourage QF development, and that in fact FERC's rules specify that a utility is not required to pay more than avoided cost. He explained that obligating a utility to pay rates to QFs that exceed its avoided costs burdens utility customers with costs in excess of what PURPA requires. (T. Vol. 5 at 131-132)

Witness Gaskill testified that, given the unprecedented level of QF development in North Carolina generally and in Dominion Energy North Carolina's service area specifically, the avoided cost rates and terms previously approved by the Commission have clearly succeeded in encouraging QF development. He also explained, however, that the influx of distributed solar generation onto Dominion Energy North Carolina's North Carolina system, and the long-term fixed avoided cost contracts Dominion Energy North Carolina is committed to under the previous biennial periods, have resulted in burdening customers with above-market payments that far exceed Dominion Energy North Carolina's actual avoided costs. (T. Vol. 5 at 140-142)

In his direct and rebuttal testimonies, Dominion Energy North Carolina witness Petrie similarly stated that while the influx of distributed solar generation onto Dominion Energy North Carolina's North Carolina system, particularly since 2014, shows that the Commission has successfully encouraged QF development in this State, this encouragement is no longer balanced with the risk of overpayment associated with QF development. He explained that this imbalance is evident in the significant disparity between the currently projected contract rates that Dominion Energy North Carolina is committed to pay QFs that entered into PPAs or established LEOs during the 2012 and 2014 biennial periods and Dominion Energy North Carolina's current expected avoided costs. He stated that, for the approximately 680 MW of solar QFs that established an LEO during the 2012 and 2014 biennial periods, Dominion Energy North Carolina is committed to pay QFs approximately $100 million per year for the next 15 years, totaling $1.4 billion. (T. Vol. 5 at 212-213)

Witness Petrie explained that these projected payments exceed the current market value of the 2012 and 2014 biennial commitments by approximately $381 million, resulting in Dominion Energy North Carolina and its customers paying rates over the lifetime of these contracts that are 46% above Dominion Energy North Carolina's actual avoided costs. He explained that the projected overpayments are the result of a combination of factors rooted in the current structure of the standard offer. First, because QFs can establish an LEO anytime during the biennial period between standard avoided cost rate determinations, those locked-in rates will not likely represent Dominion Energy North Carolina's actual avoided costs at the time the LEO is set. In addition, the potential passage of even more time before a QF facility comes online exacerbates this disparity. Witness Petrie explained further that Dominion Energy North Carolina's lower projected avoided costs are resulting from forward prices for fuel and power dropping precipitously over the last several years, as demonstrated by the difference between the average energy price Dominion Energy North Carolina paid to QFs with 2014 and 2014 biennial period contracts during 2016—$54/MWh and $48/MWh respectively—and its average on-peak LMP during 2016 of approximately $34/MWh. (T. Vol. 5 at 213-214, 239-240)

Duke witness Bowman testified that PURPA's requirement that payments to QFs be based on the utility's incremental or avoided cost ensures that customers remain indifferent as between the utility purchasing from a QF, or generating itself or purchasing from another source. (T. Vol. 2 at 312) Duke witness Snider discussed the significant financial commitments to which Duke's customers are obligated for existing QF solar power based on existing fixed price contract terms. (T. Vol. 2 at 199-201)

Public Staff witness Hinton explained that the significant growth of facilities from which the Utilities are obligated to purchase energy and capacity has increased the risk of potential overpayments by ratepayers. Regarding FERC's prediction that overpayments and underpayments of avoided costs would balance out over time, witness Hinton stated that the sheer volume of QF projects currently being developed in North Carolina from which the Utilities are required to purchase at avoided cost rates is unparalleled. (T. Vol. 8 at 23)

In his testimony, NCSEA witness Johnson contended, based on estimated costs of baseload, combined cycle (CC), and combustion turbine (CT) units that he derived using the proxy method, that the peaker method provides low-end avoided cost estimates. He suggested that QF avoided cost rates should be comparable with the cost to obtain power from a new CC plant, and that rates lower than the cost of a CC unit would be artificially low, thereby detrimentally affecting customers. (T. Vol. 7 at 165-195, 187-190)

In his rebuttal, Energy North Carolina witness Petrie stated that the problem of overpayments created by the magnitude of solar QF development, the two-year lag in setting avoided cost rates for the standard contract, and the significant drop in fuel and power prices is further exacerbated by the availability of the standard offer contract to QFs up to 5 MW, and by the standard 15-year contract term. He explained that the 5 MW eligibility threshold results in large numbers of projects sized at or just below the 5 MW limit qualifying for the biennial established standard rates and terms, and that the standard 15-year term requires Dominion Energy North Carolina and its customers to pay a standard avoided cost rate for a longer period of time that does not account for market changes. This results in a significant financial risk to customers of paying more for QF energy and capacity than actual avoided costs. (T. Vol. 5 at 240-241)

Witness Petrie agreed that FERC contemplated some disparities between estimated avoided costs and actual avoided costs, as shown by FERC's statement in implementing its PURPA rules that, in the long run, overestimations and underestimations of avoided costs should balance out. He countered, however, that the $381 million disparity between Dominion Energy North Carolina's estimated and actual avoided costs in North Carolina is of such a magnitude that this disparity is *not* balancing out, and will only increase, all to the detriment of Dominion Energy North Carolina's customers. (T. Vol. 5 at 242)

Witness Petrie testified that the intent of this case is to determine avoided costs that, as accurately as possible, represent the costs expected to be avoided by purchasing from QFs during the term of the contract. He also testified that this determination must be made in a manner consistent with PURPA and FERC requirements that avoided cost rates be just and reasonable to a utility's ratepayers and not exceed the utility's avoided costs in addition to being nondiscriminatory to QFs, as well as with the requirement that customers should be indifferent to whether the utility buys power from a QF or builds the generation itself or purchases it from another source. Witness Petrie explained that these fundamental PURPA requirements are violated by the extreme disparity between Dominion Energy North Carolina's current and projected payment obligations and its actual avoided costs. He stated that Dominion Energy North Carolina's proposals in this case are intended to reduce this risk of overpayment going forward and restore the balance between encouraging QF development and protecting utility customers from overpayments. (T. Vol. 5 at 242-243)

On further rebuttal, witness Petrie explained that witness Johnson's approach of using cost estimates derived using the proxy method to evaluate avoided cost estimates that are derived from the Commission-approved peaker method is inconsistent and inappropriate in avoided cost proceedings. Witness Petrie cautioned that the Commission should not, and cannot, consistent with PURPA, set rates above avoided costs to artificially encourage QF development, as would be the case if witness Johnson's recommendation was implemented. Witness Petrie contrasted as appropriate Dominion Energy North Carolina's comparison of the rates it is committed to pay QFs under the 2012 and 2014 biennial periods to the current market value of those commitments, which comparison he said shows that customers are clearly not indifferent as between purchases made from QFs and other purchases or build options. (T. Vol. 5 at 243-245)

DISCUSSION AND CONCLUSIONS

PURPA and FERC's rules define avoided costs as "the incremental costs to an electric utility of electric energy or capacity or both which, *but for* the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[5] In addition, PURPA provides that a utility is not required to pay a rate for purchases from QFs "which exceeds the incremental cost to the electric utility."[6] Similarly, FERC's regulations provide that an electric utility is not "require[d]" to "pay more than the avoided costs for purchases."[7] PURPA's prescription that QFs be paid "avoided costs" therefore ensures that customers remain indifferent as to whether the utility purchases from a QF or builds generation itself or purchases from another source.

We agree with Dominion Energy North Carolina that, based on the evidence of the $381 million in above-market payments it expects to make to QFs over the next 15 years or more, as compared to the value its customers will actually receive from solar QF generation, there is a serious imbalance between the interests of encouraging QF development in North Carolina and protecting customers against overpayments. As noted by Dominion Energy North Carolina witness Petrie, this amount includes not only anticipated payments to QFs that have entered into PPAs with Dominion Energy North Carolina, but also anticipated payments to QFs that have established LEOs during the previous two biennial periods. We believe that the inclusion of anticipated payments to QFs that have established LEOs but not (yet) signed PPAs appropriately determines Dominion Energy North Carolina's total anticipated QF payments for these biennial periods, since by the nature of an LEO the QF has committed to sell to Dominion Energy

[5] 18 C.F.R. § 292.101(b)(6) (2016); 16 U.S.C. § 824a-3(d) (2012) (emphasis added).
[6] 16 U.S.C. § 824a-3(b) (2012).
[7] 18 C.F.R. § 292.304(a)(2) (2016).

North Carolina and, likewise, Dominion Energy North Carolina is obligated to purchase the output at avoided cost rates consistent with the LEO. In contrast, it would not be appropriate to evaluate the Utilities' above-market payment obligations based on cost estimates derived using the proxy method of determining avoided cost or to use such estimates to set rates above avoided costs derived using the peaker method. We have concluded in previous cases that the peaker method is the most appropriate method for use in these proceedings, and no evidence presented in this case persuades us otherwise.

We also agree that, while FERC contemplated that over- and under-payments to QFs would even out over time, the evidence in this case of the magnitude of the disparity between customer obligations and actual avoided costs, and the likely increase in such disparity if changes are not made to our PURPA policies, justify our approving modifications to those policies on a prospective basis.

Dominion Energy North Carolina's customers are therefore bearing a real and observed risk of overpayments to QFs, which is not consistent with either PURPA's prohibition on utilities paying more than avoided cost or with that statute's standard of customer indifference. Changes in the Commission's PURPA implementation policies are therefore required to restore the balance. As noted above, the modifications approved in this order will better align avoided cost rates with actual avoided costs and generation capacity needs. In turn, these changes will bring our PURPA implementation structure back into compliance with the requirements of that statute and FERC's regulations that avoided cost rates be just and reasonable to utility customers and in the public interest as well as non-discriminatory to QFs, help maintain customer indifference as to the QF purchases required by PURPA, and limit the risk to utility customers of overpayment under future QF contracts. As a result, these modifications will re-establish the balance between customer protection and QF encouragement consistent with PURPA and with this Commission's goal for these biennial avoided cost proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding is found in the testimony of Dominion Energy North Carolina witness Gaskill, Duke witness Bowman, Public Staff witness Hinton, NCSEA witnesses Strunk, Harkrader, and Johnson, CCR witness McConnell, and SACE witness Vitolo, and the entire record in this proceeding.

In his direct testimony, Dominion Energy North Carolina witness Gaskill presented Dominion Energy North Carolina's proposal to limit eligibility for standard avoided cost rates and contracts to QFs with 1 MW (AC) nameplate capacity. He explained that FERC requires the Commission to determine avoided cost rates for QFs of 100 kW capacity or less. He noted that in recent avoided cost proceedings, the Commission has concluded that standard avoided cost rates should apply to renewable QFs with 5 MW or less capacity and other QFs with 3 MW or less capacity. Reducing the threshold to 1 MW at this time would, in his opinion, allow more QFs to enter into negotiated contracts rather than standard contracts, with several resulting benefits. (T. Vol. 5 at 144-145)

First, witness Gaskill testified that allowing more QFs to enter into negotiated contracts would better align avoided costs with each QF's LEO. He explained that standard avoided cost rates, which are updated biennially and are available to any eligible QF that establishes a LEO within the two-year period, can result in projects with LEOs dated late in that window receiving rates based on avoided cost calculations that are several years old by the time the projects commence commercial operations. In contrast, negotiated rates, which Dominion Energy North Carolina calculates based on data available at the time the LEO is set, allow for QF payments that better align with current market conditions, including changes in gas and power market prices. He explained further that the timely updates that are possible with negotiated rates help mitigate the compounding impact of long contract terms on the disparity between the standard rates and actual avoided costs. Given the influx of distributed solar generation in Dominion Energy North Carolina's North Carolina service area, witness Gaskill testified that the more precise negotiated approach to determining avoided costs should be extended to all QFs greater than 1 MW. (T. Vol. 5 at 144-146)

Witness Gaskill also stated that allowing more negotiated rates would permit rates and terms to be customized to each specific project and location. He explained that one of the key limitations with the current PURPA implementation approach is the inability to incentivize QFs to locate in one location over another. Because all QFs under 5 MW, regardless of location, are eligible for the same standard offer, developers' main incentive is to locate projects where they can develop them at the least expense—not where the project would provide the most value to customers. The result is a heavy concentration of distributed solar on a few substations: approximately 80% of the interconnected distributed solar on Dominion Energy North Carolina's North Carolina system is located on only 15 substations out of 42. He explained that, while geographically dispersed distributed solar generation reduces the effect of intermittent cloud cover over any single location, therefore improving reliability and minimizing integration costs (such as increased operating reserves and load imbalance charges), the distributed solar generation in Dominion Energy North Carolina's North Carolina system does not offer these benefits, because it is located on a narrowly distributed geographic and electrically-connected location with little load growth. (T. Vol. 5 at 139-140) With more negotiated contracts, Dominion Energy North Carolina would have greater opportunity to incentivize projects to locate in areas or on circuits that have a need for new generation. Witness Gaskill explained that this could be accomplished by paying for avoided line losses and capacity costs where a QF locates on a distribution circuit with excess load to offset. He noted that this would benefit both Dominion Energy North Carolina and the QFs by allowing for increased avoided cost payments for more projects located in more valuable locations. (T. Vol. 5 at 146-147)

Witness Gaskill also testified that, unlike standard offer contracts, negotiated contracts can include provisions that protect customers. For example, he noted that non-levelized rates ensure that the PPA rates better match Dominion Energy North Carolina's actual avoided costs throughout the life of the contract and protect against overpayment if the QF fails to perform later in its project life. (T. Vol. 5 at 147-148)

Finally, witness Gaskill noted that 83% (60 out of 72) of the QF PPAs Dominion Energy North Carolina had signed at the time his testimony was filed were for projects sized 5 MW or below, and that 55 of those 60 standard contracts were developed by only seven different developers, indicating that developers develop multiple 5-MW projects in order to take advantage of the two-year-old standard avoided cost rates. He concluded that reducing the standard offer threshold to 1 MW would preserve the standard offer for truly small QFs that need it and would allow rates paid to larger QFs to more closely align with the utility's actual avoided costs and protect utility customers from excessive overpayments. (T. Vol. 5 at 148, 175)

Duke witness Bowman testified that, in *Order No. 69*, FERC recognized that while standard "one-size-fits-all" avoided cost rates cannot account for the differences between QFs of various sizes and shapes, smaller QFs could be challenged by the transactional costs of bilaterally negotiating individualized rates. Witness Bowman stated that FERC balanced these concerns by requiring that in implementing PURPA states make standard rates and terms available to QFs with design capacity of 100 kW or smaller, and allowing states to make such rates and terms available to larger QFs so long as the standard rates accurately reflected the utility's avoided costs. Witness Bowman advocated reducing the threshold to 1 MW to allow rates offered to QFs above 1 MW to be more just and reasonable by basing them on a more precise assessment of the costs that particular QFs allow the purchasing utilities to avoid. She explained that the 5-MW threshold has served its purpose of encouraging particularly solar QF development in North Carolina, but has evolved from a reasonable policy for encouraging development of relatively small QFs to a highly attractive solar development business model for sophisticated and well-capitalized national developers. She testified that aligning avoided cost rates with the utility's avoided cost is consistent with PURPA's objective of ensuring that customers remain indifferent between purchasing utility generation and purchases from QFs. She also stated that this change would offer a reasonable proxy to differentiate between small QFs seeking to install renewable energy facilities for primarily non-commercial purposes and larger sophisticated commercial enterprises or power generation developers that are in the business of owning or operating generating facilities. Finally, she noted that a 1 MW threshold would be consistent both with FERC's requirement that only QFs above 1 MW must self-certify, and with Duke's recent experience with interconnection requests that projects under 1 MW are likely to pass the fast track process, thereby streamlining the PPA and Interconnection Agreement processes. (T. Vol. 2 at 338-349)

Public Staff witness Hinton testified to the Public Staff's belief that it would be appropriate under the current circumstances for the Commission to consider modifications to the standard offer threshold. He offered rationales for reducing the eligibility threshold to either 1 MW or 2 MW, but concluded that the 1 MW limit may have more practical significance. He noted that witnesses for the Utilities indicated that the reduced threshold would allow more QFs' avoided cost rates to be based on more timely information, including updated capacity needs, fuel costs, and other factors that may reduce ratepayer exposure to potential overpayments due to changing market conditions. Witness Hinton also noted that the 1 MW threshold is consistent with other regulatory contexts, including North Carolina's maximum size for net metering and the FERC requirement that only QFs with 1 MW or more of capacity must self-certify. (T. Vol. 8 at 59-60)

NCSEA witnesses Strunk and Harkrader and CCR witness McConnell expressed concern in their testimonies that lowering the eligibility limit for the standard offer from 5 MW to 1 MW would impact QFs' ability to finance some projects. Witness Strunk stated that he sometimes sees pools of small projects being financed together as a group. (T. Vol. 6 at 24) Similarly, witness McConnell testified that the only way to make most financings work with a 5 MW threshold is to group them into portfolios to create critical mass for debt and tax equity investors. (T. Vol. 6 at 117) Witness Harkrader testified that reducing the standard offer threshold to 1 MW would require any QF greater than 1 MW to negotiate a contract, which she anticipated to be difficult when combined with a reduced term. (T. Vol. 7 at 380-381)

SACE witness Vitolo averred that reducing the standard offer eligibility threshold from 5 MW to 1 MW would have negative consequences related to what he termed the "lengthy, resource-intensive, power imbalanced bilateral negotiation process," the significant loss of economies of scale, and the ramifications of a significant increase of interconnection requests or bilateral negotiations. (T. Vol. 7 at 26) He noted that the Commission rejected a similar proposal by the utilities to reduce the size of the project eligible for the standard contract in the 2014 biennial proceeding. (T. Vol. 7 at 29-30)

NCSEA witness Johnson recommended adjusting the size threshold from 5 MW down to 3.75 MW or 4 MW based on his assertion that the Commission should proceed with caution to gauge how the market reacts before making further adjustments. (T. Vol. 7 at 329)

In his rebuttal, witness Gaskill responded that, while Dominion Energy North Carolina cannot know every potential QF's financing ability, QF developers in North Carolina tend to have large portfolios of generation projects around the country, and to be well-capitalized companies with access to financing resources that afford them the ability to negotiate a PPA. Referencing his direct testimony that 60 of 72 PPAs Dominion Energy North Carolina has signed are for projects at or under 5 MW, and that 55 of those 60 contracts were signed by just seven developers, he also observed that these developers break up large portfolios of projects into multiple 5-MW projects in order to qualify for the standard offer, including standard avoided cost rates that can be two years old by the time a QF establishes an LEO. He noted especially the testimony of witness Strunk and witness McConnell that they group together multiple small projects in order to improve the financing terms of a larger portfolio. (T. Vol. 5 at 174-175)

Witness Gaskill also testified that in his opinion, large solar developers do not require the standard offer in order to develop QF projects. He explained that, based on his experience, larger developers have resources and sophistication to negotiate contracts, and the market would be better served by removing the incentive to break up the projects into small increments. He noted that witness McConnell's company, Cypress Creek Renewables, claimed on its web site that it had raised and invested over $1.5 billion and deployed or developed over 4 *gigawatts* of local solar farms, and that it is the largest and fastest-growing dedicated provider of local solar farms. He opined that it would be illogical for large, sophisticated developers like Cypress Creek to require a standard offer in order to successfully finance and complete solar projects in North Carolina. Finally, witness Gaskill testified that the intent of the standard offer contract is to provide simplified and standard market access for truly small developers, not to permit large developers to break up large solar deployments into small individual projects in order to obtain higher pricing and better financing terms, which he stated in his opinion is occurring now in North Carolina. (T. Vol. 5 at 175-176)

Witness Gaskill also testified that the standard offer threshold reduction will ultimately realize a positive benefit to developers, utilities, and customers in all of the areas identified by witness Vitolo. Noting that in some cases a negotiated PPA may take additional time up front, he nonetheless explained that over the life of the contract significantly less resources are required to administer a single 20-MW contract than multiple small project contracts. He explained that, regardless of whether an executed contract is standard or negotiated, it requires approximately the same number of hours to administer, including labor-intensive tasks such as performing monthly meter readings, settlement, invoice and billing, and payments. He stated that with its proposal to reduce the threshold to 1 MW, Dominion Energy North Carolina intends to encourage developers to build fewer, but larger, projects, and thus greatly reduce the number of resources required to originate and administer the volume of QF contracts under consideration. (T. Vol. 5 at 176-177)

With regard to the balance of power in contract negotiations, witness Gaskill emphasized that the utility retains the obligation under PURPA to purchase QF output and cannot walk away from a negotiation. He noted in addition that the procedures for establishing avoided cost rates and the vast majority of terms and conditions of negotiated contracts are fairly well established such that they support efficient and successful negotiations, and that rarely do large contract negotiations include much negotiation or dispute regarding the contract rates themselves, since the rates are calculated based on avoided costs as of the LEO date for each project. He noted that Dominion Energy North Carolina has successfully negotiated contracts with 12 QFs totaling 214 MW. (T. Vol. 5 at 177-178)

Finally, with respect to economies of scale and the interconnection queue, witness Gaskill explained that by removing the incentive to divide a portfolio of projects into 5-MW increments, reducing the standard offer threshold to 1 MW will encourage developers to seek larger projects. The change will therefore actually increase economies of scale and reduce the number of projects in the interconnection queue over time, while preserving the benefit of the standard offer contract for the truly small projects. (T. Vol. 5 at 178)

Concerning the Commission's previous decisions on this issue, witness Gaskill reiterated that the landscape of QF development in this State has changed significantly since the 2014 biennial proceeding. He noted that the Commission in this case must determine what the appropriate standard offer will look like for QFs developed going forward from this case, and that what may have been appropriate two years ago must be adapted to the circumstances Dominion Energy North Carolina faces today and anticipates it will face in the next two years. Witness Gaskill concluded that more negotiated contracts will provide important protection for customers by reducing the risk of overpayments to a large portfolio of QF projects. (T. Vol. 5 at 178-179)

In her rebuttal, Duke witness Bowman testified that NCSEA witness Johnson's recommendation to reduce the size threshold to 3.5 MW or 4 MW would likely only perpetuate the issues that have resulted from the 5 MW threshold. (T. Vol. 2 at 385)

At the hearing, witness Gaskill testified, in response to questions by counsel for NCSEA regarding Dominion Energy North Carolina's first quarter 2017 interconnection queue report submitted in Docket No. E-100, Sub 101A, that seven active projects listed on the report have capacities greater than 5 MW and that the capacity of the remaining projects is approximately 5 MW. (T. Vol. 6 at 47) He also testified in response to questions by counsel for the Attorney General's Office that, through repeated negotiations over time, Dominion Energy North Carolina arrives at essentially a standard contract with each developer. (T. Vol. 6 at 69-70)

Also at the hearing, CCR witness McConnell testified in response to counsel for the Public Staff that his company has approximately 105 operational projects in North Carolina, and that of those, about 85% are in the 5-MW range. He also agreed that there are economies of scale associated with developing larger projects in terms of lower build costs and amortizing fixed costs. (T. Vol. 6 at 121-122, 124)

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, we conclude that it is appropriate to reduce the upper limit of size eligibility for standard avoided cost rates and contracts for all QFs to 1 MW.[8] As an initial matter, FERC's regulations implementing PURPA do not require this Commission to maintain any upper threshold on the size eligibility for standard contracts other than the 100 kW provided in those rules.[9] Neither is there any requirement in PURPA or FERC's regulations that we maintain the 5-MW standard offer limit that has been determined in previous biennial proceedings before this Commission to be appropriate. We note that the Utilities have not proposed to reduce the size threshold down to the 100 kW minimum prescribed by FERC.

In Phase 1 of the previous biennial avoided cost proceeding, we concluded that the 5-MW limit on eligibility for the standard avoided cost offer should be maintained. We noted in reaching that conclusion that the evidence in that case showed few negotiated contracts being negotiated with QFs larger than 5 MW, despite a large amount

[8] In the 2014 biennial proceeding, Duke entered into a stipulation with the NC Hydro Group pursuant to which small run-of-river hydroelectric QFs, defined as those with capacity of 5 MW or less, would receive a PAF of 2.0 and 5, 10 and 15-year term options until December 31, 2020. Dominion Energy North Carolina was not a party to that stipulation and does not appear to have any hydroelectric QFs in its service area in this State.

[9] *See* 18 C.F.R. § 292.304(c)(1), (c)(2) (2016).

of QF development (which we described as CPCNs granted and interconnection requests made).[10]

However, in light of the significant influx of solar QF development that has occurred in North Carolina since that proceeding, which has resulted in hundreds of MW of solar QF capacity being developed at or around the 5-MW limit for the standard offer, and therefore qualifying for what are often, by the time they reach completion, stale avoided cost rates, we agree with the Utilities that the balance we have attempted to strike on this issue in past avoided cost proceedings is no longer working, and that a different approach is now appropriate. Given these recent changes in the landscape of QF development in this State, the 5-MW limit is no longer consistent with the requirements of 18 C.F.R. § 292.304 that standard QF rates be just and reasonable to the utility consumer, in the public interest, and not discriminatory against QFs, and the provision in that rule that a utility is not required to pay more than its avoided costs. Neither is the current 5-MW limit consistent with the indifference standard contained in PURPA's and FERC's definition of avoided cost as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from a QF, the utility would generate itself or purchase from another source.

In reaching these conclusions, we are persuaded by the testimony provided by Dominion Energy North Carolina regarding the disparity that has developed between locked-in avoided cost payments and actual utility avoided costs. Further, we agree with Dominion Energy North Carolina that, with the influx of distributed solar generation in Dominion Energy North Carolina's North Carolina service area, extending to all QFs

[10] *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014*, Order Setting Avoided Cost Input Parameters at 20, Docket No. E-100, Sub 140 (Dec. 31, 2014) (Phase 1 Order).

with capacity above 1 MW the more precise and timely updates to avoided cost determinations that are possible with negotiated rates will help mitigate going forward the compounding impact of this disparity over long contract terms by allowing rates paid to larger QFs to more closely align with the utility's actual avoided costs as well as protect utility customers from excessive overpayments. We also agree that, by allowing more QFs to receive negotiated rates, the utilities will be able to customize avoided cost rates and terms to each specific project and location.

In addition, we believe this change will help address on a prospective basis a circumstance that had not become apparent during the 2014 biennial proceeding, which is the heavy concentration of distributed solar on a limited number of Dominion Energy North Carolina's North Carolina substations. Reducing the standard size limit will allow Dominion Energy North Carolina to give projects reasons to locate where Dominion Energy North Carolina actually needs additional generation by evaluating the specific benefits of locating at a particular location.

While the Utilities offered testimony in the previous proceeding as to the sophistication of solar QF developers, the evidence provided in this proceeding clearly shows that a small number of sophisticated, national solar energy developers are taking advantage of the standard offer available in North Carolina by developing the vast majority of projects right at or around 5 MW. Notably, several witnesses testifying on behalf of developers stated that they pool 5-MW projects together for financing purposes, and also testified that greater economies of scale can be achieved by developing larger projects as opposed to smaller ones. We agree with Dominion Energy North Carolina that the intent of the standard offer contract is to provide simplified and standard market access for truly small developers, not to permit large developers to break up large solar deployments into small individual projects in order to obtain higher pricing and better financing terms, and believe that this change will help curb that practice which has developed in recent years by large developers that no longer need the standard offer to enable them to bring QF facilities online.

With regard to concerns about increased numbers of projects requiring negotiations, we are persuaded that, due to the large and sophisticated nature of the developers currently operating in North Carolina, and as evidenced by these companies' recent development practices, they are well equipped to negotiate avoided cost rates for themselves. We also find persuasive the testimony offered by the Utilities that, since they are repeatedly negotiating with the same developers, they have essentially developed template non-standard contracts, with the vast majority of provisions already agreed to, that they can then use as a starting point in negotiations for specific projects. We note in this regard that Dominion Energy North Carolina has successfully negotiated 12 non-standard PPAs. We recognize Dominion Energy North Carolina's intent that this change in the size limit will incentivize developers to construct fewer, larger projects rather than a multitude of small ones, thereby streamlining the contract administration requirements, and are persuaded moreover by Dominion Energy North Carolina's testimony that the administrative burden is less to manage one 20-MW contract than several 5-MW contracts. Also, to the extent that any increase in administrative burden does occur as a result of this change, we conclude that any such increase is outweighed by the degree of the burden on customers of not reducing the eligibility limit to 1 MW due to the stale avoided cost rates they will be required to pay.

As a final point on this issue, we conclude that a 1-MW size threshold is consistent with other regulatory prescriptions, and note as pointed out by witness Bowman and witness Hinton that a 1 MW size limit for the standard offer rates and terms aligns with both North Carolina's maximum size for net metering and the FERC requirement that only QFs with 1 MW or more of capacity must self-certify. Depending on the outcome of the stakeholder process currently evaluating the North Carolina Interconnection Standard in Docket No. E-100, Sub 101, the 1 MW limit also has the potential to complement the size of facilities that generally qualify for fast track processing of interconnection requests.

As we have explained in previous avoided cost decisions, the Commission must reconsider the availability of long-term levelized rate options as economic circumstances change from one biennial proceeding to the next, balancing the federal and North Carolina public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on customers. We note in this regard that the Public Staff, which continued to support the 5-MW threshold in the 2014 biennial proceeding, now believes that, based on the change in circumstances since that proceeding, the reduction in the standard offer threshold merits reconsideration. Based on the foregoing, the Commission concludes that in light of the current circumstances of solar QF development in this State, the Utilities should each offer standard long-term levelized rate options to any QF contracting to sell 1 MW or less. With this modification, and the resulting better matching of avoided cost rates to QF LEOs and ability to customize avoided cost rates to each QF's specific location and characteristics, PURPA's requirements that avoided cost rates be just and reasonable to utility customers and that customers remain indifferent to QF payments will be met.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding is found in Dominion Energy North Carolina's Initial Filing, the direct and rebuttal testimony of Dominion Energy North Carolina witness Gaskill, the rebuttal testimony of Duke witness Bowman, the testimony of Public Staff witness Hinton, SACE witness Vitolo, NCSEA witnesses Strunk and Harkrader, and CCR witness McConnell, and the entire record in this proceeding.

In his direct testimony, Dominion Energy North Carolina witness Gaskill discussed Dominion Energy North Carolina's proposal as contained in its Initial Filing to reduce the maximum term of a standard avoided cost contract from 15 years to 10 years. He testified that the goal of this proposal is to mitigate customers' exposure to the significant above-market payments for QF output that are resulting under current 15-year contract obligations. He explained that, since the fixed long-term prices contained in PURPA contracts are based on projections of future costs for electricity, factors such as technology advances, declining equipment costs, and new fuel supply sources unavoidably prevent the rates paid under these contracts from exactly matching the utility's actual avoided cost in any given year of the PPA. Due to the decline in fuel and power prices in the last few years in particular, Dominion Energy North Carolina is significantly overpaying QFs with PPAs or LEOs obtained under the 2012 and 2014 standard offers. He also explained that longer term contracts increase the over/under payment created by the levelized rates available under the 2014 standard offer, as the QF receives rates that exceed Dominion Energy North Carolina's actual avoided cost in the contract's early years, and rates that are less than the actual avoided cost in the late years. (T. Vol. 5 at 160-162) Witness Gaskill argued that reducing the maximum standard offer contract term to 10 years will help address the more severe mismatch between locked-in contract prices and actual avoided costs that results from longer contract terms. (T. Vol. 5 at 158-160)

Witness Gaskill testified that this proposal is consistent with PURPA and FERC's implementing rules and precedent. First, a 10-year term provides a basis for long-term project financing, as evidenced by the 5 of 12 non-standard contracts Dominion Energy North Carolina has entered into with solar QFs that contain 10-year terms, and that have shown the ability to achieve financing by either commencing operations or reaching late-stage development. Additionally, he noted that even with a reduced maximum term, Dominion Energy North Carolina still retains the obligation under PURPA to purchase QF output at the end of the contract period; the shorter contract term simply allows the prices Dominion Energy North Carolina must pay to align more closely with its actual avoided costs. (T. Vol. 5 at 162-163)

In his testimony, Public Staff witness Hinton cited state policy interests noted by the Commission when previously deciding to maintain the 15-year maximum term. These include the requirement of G.S. 62-156(b)(1), which applies to hydroelectric facilities, that long-term contracts be encouraged in order to enhance the economic feasibility of small power production facilities, and the provision of G.S. 62-133.8(d) that the terms of any contract entered into between an electric power supplier and a new solar electric or thermal facility be of sufficient length to stimulate development of solar energy. (T. Vol. 8 at 66) He noted FERC's recent decision that QFs are entitled to contracts “long enough to allow QFs reasonable opportunities to attract capital from potential investors.” (T. Vol. 8 at 68) He asserted that a utility’s commitment to build a plant represents a similar type of long-term fixed obligation for utility customers, based largely on forecasts of future prices. (T. Vol. 8 at 70) He noted the Commission’s recognition of FERC’s conclusions that ratepayers benefit from QFs other than through direct avoided costs. (T. Vol. 8 at 71-72)

Witness Hinton concluded, however, that due to the rapid pace of QF development that has recently occurred in this State, it is appropriate at this time to consider a shorter-term structure for avoided cost rates. He noted numerous examples of solar QFs obtaining financing with a 10-year contract term. He also noted that FERC rules require utilities to make available data from which avoided costs may be derived. He explained that a shorter contract term would reduce the risk borne by ratepayers for overpayments over a longer term, and that the Utilities’ proposal to limit the standard offer term to 10-year fixed PPAs is reasonable. (T. Vol. 8 at 72-73)

While acknowledging that large solar QFs have been constructed with 10-year contracts, SACE witness Vitolo questioned whether projects less than 5 MW or greater than 10 MW would be financeable in the future with contracts of that duration. (T. Vol. 7 at 31) Witness Vitolo also suggested that solar QFs are treated differently than utility projects, since utility-sponsored projects depreciate capital over their lives. He noted that Dominion Energy North Carolina has in Virginia three PV generators in rate base to be depreciated over a 35-year period. He contended that the longer depreciation schedule allows for reduced near-term rate impact, thus making utility-built project investment more attractive. (T. Vol. 7 at 33)

Several intervenor witnesses expressed concern with the proposed standard term reduction based primarily on their claim that a reduced term will increase financing costs. CCR witness McConnell stated that limiting contracts to 10 years would require additional equity investment and increase the cost of debt, thus reducing the rate of return the developer will realize on the project. (T. Vol. 6 at 115-116) NCSEA witness Strunk similarly asserted that a reduced PPA term will increase the cost of capital for investors and short-term cash requirements. (T. Vol. 6 at 19) NCSEA witness Harkrader testified that a QF would face a smaller pool of potential debt and equity investors for a contract term shorter than 15 years. (T. Vol. 7 at 378)

On rebuttal, Dominion Energy North Carolina witness Gaskill pointed out in response to SACE witness Vitolo's testimony that Dominion Energy North Carolina does not have 10-year PPAs with QFs sized under 5 MW simply because QFs that size have been eligible for the standard offer 15-year term. Witness Gaskill also stated that the developers of QFs sized at or under 5 MW and those sized greater than 5 MW are not distinguishable, since such developers, as admitted by their witnesses, simply break up their project portfolios into smaller increments to qualify for standard offer rates. He testified that, if developers can obtain financing for large projects with a 10-year term, they should be able to do so for small projects as well, due to the practice of, as NCSEA witness Strunk testified, financing pools of small projects together as a group. (T. Vol. 5 at 181-182)

Witness Gaskill also explained that assertions regarding QF versus utility-sponsored projects ignore fundamental differences between rate regulated utilities and QFs in terms of organization, regulation, financing, cost recovery, and the obligation to serve customers. He pointed out that utilities operate under cost-of-service rate recovery, which means that when a utility builds a plant and places it in rate base, it does not receive avoided cost for energy and capacity. Instead, the utility earns a return on the capital investment required to meet its obligation to serve, but all of the benefits of the facility are passed directly to customers via lower fuel or base rates. He provided the example of Dominion Energy North Carolina constructing a solar facility and placing that facility in rate base, in which case all of the benefits, including fuel savings, revenue from RECs, and investment tax credits (ITC) generated by the facility are passed on to customers. In contrast, he noted, QFs are paid marginal, which is the highest, costs for both capacity and energy and they retain all of the other revenue streams such as from RECs and ITCs for themselves. Additionally, under the cost-of-service recovery mechanism, Dominion Energy North Carolina may earn only what the Commission approves, since the Commission determines the cost of debt and equity and overall capital structure in a rate case after receiving and considering evidence. In contrast, he pointed out, QFs are not limited as to the amount of debt they may use for financing, their return on equity, or overall rate of return on a particular investment. (T. Vol. 5 at 183-184)

Witness Gaskill also noted that Dominion Energy North Carolina faces a much higher burden than do QF developers when seeking to obtain a CPCN and cost recovery for a new project. He explained that the utility must demonstrate that the investment can be used to meet customer needs at the least possible cost, and cited the three Virginia solar facilities referenced by witness Vitolo as cases where Dominion Energy North Carolina, in seeking CPCNs for those facilities, provided the Virginia State Corporation

Commission (VSCC) evidence that customers would save an estimated $32 million net present value below projected market rates. He noted that the VSCC typically only approves a project if it is shown to be favorable for customers relative to other options. Finally, witness Gaskill agreed that longer depreciation lives for utility rate-based assets lower the near-term rate impact for utility projects. He explained, however, that this is appropriate because the lower annual depreciation costs are passed directly to customers via a lower revenue requirement. He noted in contrast that no near-term rate reduction accompanies longer QF contract terms; instead, any savings from the longer depreciation and lower financing costs are kept entirely by the QF, therefore increasing customer risk of overpayment with no offsetting cost benefit. (T. Vol. 5 at 183-185)

Witness Gaskill also testified that, while he has no reason to question developers' claims that a shorter term will, all else being equal, change financing requirements, that potential result is not a compelling reason to expose customers to the risk that accompanies 15-year fixed price contracts at avoided cost. He explained that, while PURPA's goal is to encourage QF development, he was not aware of any PURPA provision or rule that entitles developers to rates that ensure a particular rate of return or that guarantees any particular project (or class of projects) the ability to obtain financing. He stated that, instead, FERC promulgated the requirement cited by witness Hinton, that utilities must provide data from which avoided costs may be derived, based on its belief that in order to evaluate the financial feasibility of a QF project, an investor must be able to estimate the expected return on investment with reasonable certainty. He noted that the maximum financial feasibility period that FERC incorporated in that rule was 10 years. (T. Vol. 5 at 185-186)

Witness Gaskill concluded that Dominion Energy North Carolina's experience is that a 10-year term is of sufficient length to allow QFs to obtain financing and complete projects, as evidenced by the five non-standard contracts with 10-year terms that Dominion Energy North Carolina has entered into with solar QFs, including all but one of such contracts signed within the past two years. (T. Vol. 5 at 182-183) He concluded that a 10-year term is reasonable for the standard offer contract at this time, because it strikes an appropriate balance between encouraging QF development and protecting customers by reducing the risk of overpayments due to changes in market conditions over time that result in contract rates misaligning with actual avoided costs. He testified that, while PURPA's intent is to encourage QFs, PURPA's express requirements that rates paid to QFs be just and reasonable to utility customers and not exceed the utility's avoided costs, as well as the lack of any particular stated minimum term or guarantee of QF financing, show that that purpose is not intended to place customers at a disadvantage or to force them to pay more than their actual avoided costs. He stated that reducing the maximum contract term to 10 years will help ensure that rates paid to QFs better align with actual avoided costs through the life of the contract while continuing to encourage QF development in North Carolina. (T. Vol. 5 at 186-187)

In her rebuttal testimony, Duke witness Bowman noted that FERC's regulations have long provided a method for QF investors to evaluate the utility's longer-term need for capacity and forecasted cost of energy. She explained that Section 292.302 of FERC's rules requires utilities to biennially file with the Commission forecasted electric utility system cost data for energy and capacity. She testified that, as explained by FERC in *Order No. 69*, this data can then be used by QFs and their investors to evaluate the utility's future avoided costs. (T. Vol. 2 at 401-402)

Witness Bowman also testified that FERC's recent *Windham Solar* declaratory order found that given the QF's need to enter into contractual commitments based upon estimates of future avoided costs and the need for certainty with regard to return on investment, PURPA's directive to encourage QFs suggests that an LEO should be "long enough to allow QFs reasonable opportunities to attract capital from potential investors." Witness Bowman noted that FERC also reiterated that its rules do not specify a particular number of years for such LEOs, meaning that the term and structure of forecasted avoided cost rates is left to the discretion of the implementing state regulatory authority. (T. Vol. 2 at 403-404)

Witness Bowman also described the differences between QF contracts and utility-owned generation. First, she noted that utility generation resource additions are driven by need; they are not compensated by customers for energy produced from generating facilities until they establish the need for new generation through an extensive IRP process and they receive a CPCN based on a Commission determination that the facility is the least-cost resource to meet that need. In contrast, she explained, the PURPA must-purchase requirement mandates that QFs be reimbursed for selling power to utilities whether or not the power is needed. Second, she noted that because utility load-following generating resources are dispatchable, they can be backed down when more economic alternatives are available. In addition, because utilities are not locked in to long-term fixed contracts, they can pass lower fuel and other operating cost savings to customers. In contrast, a QF facility cannot be dispatched or backed down when more economic alternatives are available, so customers ultimately pay for potentially higher-cost QF energy produced by a QF, an inefficiency that is exacerbated with long-term contracts. Finally, she testified that the full avoided cost rates that QFs receive are not related to the cost of the QF project, whereas capital costs of utility generating assets are determined based upon cost and recovered over their depreciable useful lives. (T. Vol. 2 at 411-412)

At the hearing, witness Petrie testified that the depreciation length of the three solar facilities that Dominion Energy North Carolina has in rate base is 35 years. (T. Vol. 6 at 57-58). Witness Gaskill further clarified the distinction between the avoided cost context and the utility self-build context, particularly with respect to changing cost forecasts. He explained that when Dominion Energy North Carolina needs additional generation to meet energy and capacity requirements, it determines the least cost option for obtaining that generation, taking into account fuel diversity and other factors, and must obtain Commission approval through a CPCN proceeding for investment in build options. He acknowledged that fuel forecasts can change from the time the decision to build or buy was made, but noted that when Dominion Energy North Carolina decides to build, the price is below the projected market price, or it would not make that decision. On redirect, witness Gaskill agreed that when Dominion Energy North Carolina decides to build generation, it must show that that is the least cost option, that there is a need for the generation, and that it could not purchase the generation from another source for less cost. He also agreed that Dominion Energy North Carolina customers still benefit from a utility-built generator even if the initial cost forecast changes, because the utility will only run the unit when it makes economic sense to do so. He contrasted that option with the take-or-pay context of a QF facility where Dominion Energy North Carolina has no choice whether to take the power. Finally, he agreed that while Dominion Energy North Carolina annually adjusts the fuel portion of its rates to reflect increases and decreases in the market through Commission proceedings, such is not the case with avoided cost contracts, which lock in prices for the duration of the contract. (T. Vol. 6 at 49-50, 93)

<u>DISCUSSION AND CONCLUSIONS</u>

Based on the evidence in this proceeding, it is clear that the 15-year maximum standard offer contract term is no longer supporting the balance between the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs on the other that we seek to achieve in these proceedings. The Utilities' proposed reduction of the maximum standard term to 10 years will help reset this balance, and should be approved.

In reaching this conclusion, we believe the significant above-market payments to which the Utilities are committed under the two previous standard offers demonstrate the risk associated with requiring a 15-year term. We also note that, in addition to the high levels of solar QF capacity that are reflected in contracts that have been executed and in currently effective LEOs, the Utilities face even greater amounts of such capacity being developed and coming online in the next few years, based on the number of projects that have filed interconnection requests or received CPCNs for their projects. This means that, if we do not modify the standard offer to reduce the maximum contract term, customers will bear even higher risk of even greater above-market payments than they currently face for the next 15 or more years under current obligations. We also recognize that this risk is compounded by the levelized nature of the rates provided under standard offer contracts.

Attempts to justify contract terms in excess of 10 years based on comparisons of QF developer investments and avoided cost payments to utility decisions regarding building or buying capacity and utility cost recovery are not appropriate, for the many reasons explained by witness Bowman and witness Gaskill, which clearly distinguish between these investment decisions and cost recovery methods. Capacity procurement outside the PURPA context is based on least-cost decision-making; if a QF was among the options that Dominion Energy North Carolina was considering for procuring energy or capacity (rather than being a required put, which it is), Dominion Energy North Carolina would not choose the QF power if the economic choice was to procure that power on the market. As for rate recovery, in the avoided cost context our goal is to determine the costs that the Utilities have a reasonable expectation of avoiding. Utility cost-of-service rate making is a completely different exercise. For these reasons, and because none of the three Dominion Energy North Carolina solar facilities located in Virginia are QFs, it is not useful to compare those facilities' depreciation lives to the standard avoided cost contract term.

With respect to the testimony of the developers' witnesses that QF developers may encounter different financing terms or structures with shorter-term standard contracts, as a preliminary matter we note that neither PURPA nor any FERC rule implementing PURPA entitles developers to rates that ensure a particular rate of return or that guarantees any particular project the ability to obtain financing. We also agree with Dominion Energy North Carolina witness Gaskill that the potential for changes to developers' financing terms is not a compelling reason to expose customers to the risk that accompanies 15-year fixed price contracts at avoided cost. In addition, as the evidence in this case shows, a 10-year term still provides a basis for long-term project financing, as evidenced by the 5 of 12 non-standard contracts Dominion Energy North Carolina has entered into with solar QFs that contain 10-year terms, and that have shown the ability to achieve financing by commencing operations or reaching late-stage development.

Reducing the maximum standard avoided cost contract term is also consistent with PURPA and FERC's implementing rules. In particular, we emphasize that regardless of the length of the contract term, the QF still receives fixed rates over the course of that term, and the utility still retains the obligation under PURPA to purchase QF output at the end of the contract period. We agree with Dominion Energy North Carolina that a shorter contract term simply allows the prices the utility must pay to align more closely with its actual avoided costs, as they are recalculated with the start of the new term. We also note that, while PURPA's goal is to encourage QF development, neither PURPA nor FERC specify any particular length of contract term as qualifying as a "long-term."

While FERC does not specify what is meant by "long-term," a 10-year term is consistent with the requirements contained at Section 292.302(b) of FERC's regulations. As witnesses for the Utilities and the Public Staff testified, this rule requires that utilities make available every two years to this Commission data "from which avoided costs may be derived." Notably, the prospective timeframe required for estimated avoided energy cost data is 5 years,[11] and prospective timeframe for the required capacity plan cost data is 10 years.[12]

As Dominion Energy North Carolina noted, in the order promulgating that rule, FERC stated that "in order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate with reasonable certainty the expected return on a potential investment before construction of a facility."[13] The ability to estimate expected return on investment with "reasonable certainty" was addressed in FERC's recent *Windham Solar*[14] ruling. In that ruling, which took the form of an advisory order and not a precedential decision, FERC stated that, given the "'need for certainty with regard to return on investment'" espoused in *Order No. 69*, coupled with PURPA's mandate to "'encourage'" QFs, an LEO should be "long enough to allow QFs reasonable opportunities to attract capital from potential investors." *Windham Solar* at P 8. This ruling does not mandate that all QFs, or any particular QF, be guaranteed any particular terms of financing. It simply suggests that contract terms be sufficient to allow for "reasonable opportunities to attract capital." Based on the fact that Dominion Energy North Carolina has executed non-standard contracts with 10-year terms with several projects, we believe the 10-year maximum term is consistent with this declaratory ruling, as well as with *Order No. 69* and PURPA's directive to encourage QF development.

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[11] 18 C.F.R. § 202.302(b)(1) (2016).
[12] 18 C.F.R. § 292.302(b)(2)-(3) (2016).
[13] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978,* Order No. 69, 45 Fed. Reg. 12,214, at 12,218 (Feb. 25, 1980) ("*Order No. 69*") (available at https://www.ferc.gov/industries/electric/gen-info/qual-fac/orders/order-69-and-erratum.pdf).
[14] *Windham Solar LLC,* 157 FERC ¶ 61,134 (2016) ("*Windham Solar*").

Based on the foregoing, we agree with Dominion Energy North Carolina that reducing the maximum term of the standard offer contract from 15 years to 10 years provides QFs with a contract of sufficient length, and sufficient certainty, to obtain financing and complete their projects, while mitigating utility customers' exposure to the risk of significant future above-market payments, such as they are committed to under existing standard offer obligations.

The Commission therefore concludes that Dominion Energy North Carolina should offer long-term levelized rates and contract terms for 5-year and 10-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 1 MW or less, and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass QFs contracting to sell 1 MW or less. As with previous avoided cost decisions, the standard levelized rate option of 10 years should include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration. Also consistent with these prior decisions, Dominion Energy North Carolina should offer the standard five-year levelized rate option to all other QFs contracting to sell 1 MW or less capacity. With this modification to the maximum term for standard offer contracts, long-term contract options serve to both encourage QF development and reduce the Utilities' exposure to overpayments.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding is found in Dominion Energy North Carolina's Initial Filing and the testimony of Dominion Energy North Carolina witness Petrie.

In its Initial Filing, Dominion Energy North Carolina described the two standard avoided cost rate schedules filed in this proceeding, Schedule 19-FP and Schedule 19-LMP. As discussed in the Initial Filing and the testimony of Dominion Energy North Carolina witness Petrie, and as with the last several avoided cost proceedings, energy prices under Dominion Energy North Carolina's proposed Schedule 19-LMP are based on the hourly PJM Interconnection, L.L.C. (PJM) Dominion Zone (DOM Zone) Day Ahead Locational Marginal Price (LMP) expressed as $/MWh. The average of the Day Ahead LMP values in the billing month, divided by 10 to derive a cents per kWh price, is applied to the QF's total net generation during the billing month. As discussed further below, Dominion Energy North Carolina has proposed to not offer capacity credits under either Schedule 19-LMP or Schedule 19-FP. No party contested Dominion Energy North Carolina's proposal to continue to offer Schedule 19-LMP as an alternative to Schedule 19-FP or raised any issue with the proposed Schedule 19-LMP.

DISCUSSION AND CONCLUSIONS

Based upon the foregoing, the Commission concludes that it is appropriate for Dominion Energy North Carolina to continue to offer, as an alternative to avoided cost rates derived using the peaker method, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, subject to the same conditions, except as noted below, as approved in the final Order in Docket No. E-100, Sub 106. Finally, in its compliance filing pursuant to this order and as discussed further below, Dominion Energy North Carolina shall revise Schedule 19-LMP to provide that the energy price that Dominion Energy North Carolina will pay is the LMP at the PJM-defined nodal location nearest to where the energy is delivered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in Dominion Energy North Carolina's Initial Filing and the testimony of Public Staff witness Hinton.

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

In his testimony, Public Staff witness Hinton stated that the three options directed by the Commission in previous proceedings should remain available to QFs. He noted that if the utility does not have a Commission-approved active solicitation underway, it is appropriate that any unresolved issues arising during negotiations be subject to arbitration by the Commission at the request of the utility or the QF. (T. Vol. 8 at 60-61)

DISCUSSION AND CONCLUSIONS

No party proposed that the Commission alter its prior position on this issue. Any competitive bidding proposal recognized by the Commission would complement this finding. Therefore, the Commission concludes that the Utilities should continue to be required to offer QFs not eligible for the standard long-term levelized rates the option of contracts and rates derived by free and open negotiations or, when explicitly approved by Commission order, participation in the utility's competitive bidding process for obtaining additional capacity. The QF also has the right to sell its energy on an "as available" basis pursuant to the methodology approved by the Commission.

The Commission has previously ruled that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Such arbitration would be less time consuming and expensive for the QF than the previously utilized complaint process. The Commission concludes that the arbitration option should be preserved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding is found in Dominion Energy North Carolina's Initial Filing, and in the testimony of Dominion Energy North Carolina witness Petrie, Public Staff witness Hinton, SACE witness Vitolo, and NCSEA witness Johnson.

Dominion Energy North Carolina's Initial Filing and the testimony of Dominion Energy North Carolina witness Petrie described the methodology used to calculate avoided energy cost rates under its proposed Schedule 19-FP and Schedule 19-LMP. Witness Petrie explained that the avoided energy cost rates proposed in this case for its Schedule 19-FP were calculated using the peaker method, and that, as in previous proceedings and discussed above, energy rates under Schedule 19-LMP are based on the hourly PJM DOM Zone Day-Ahead LMP expressed in $/MWh. He described the peaker method as it applies to energy as determining avoided energy costs based on the forecasted marginal energy costs of the system in each hour. Witness Petrie testified that Dominion Energy North Carolina uses the PROMOD production cost model to derive avoided energy cost rates for Schedule 19-FP, with those rates reflecting an adjustment to reflect the locational value of energy in Dominion Energy North Carolina's North Carolina service area where QFs are located, plus a fuel hedging benefit. He stated that Dominion Energy North Carolina uses the PROMOD output results to calculate the levelized on-peak and off-peak long-term fixed energy rates for the various contract durations under Schedule 19-FP. (T. Vol. 5 at 215-218)

Witness Petrie also explained that, consistent with Commission directives issued in the 2014 biennial proceeding, as well as with the price forecasting methodology contained in its 2016 and prior IRPs, for purposes of determining avoided energy costs in this proceeding Dominion Energy North Carolina maintained its approach of using estimated forward market prices for fuel, PJM power, and emission allowance for the first 18 months of the forecast period, a blend of forward market prices and ICF commodity price forecast as of early October 2016 for the next 18 months, and exclusively ICF commodity price forecast for the remainder of the term (starting in October 2019). (T. Vol. 5 at 248) He stated that this approach is consistent with the directive of the Commission's Phase 2 Order issued in the 2014 biennial proceeding that the Utilities calculate avoided energy rates using commodity forecasts constructed in a manner consistent with their IRPs. He clarified that that order did not require that the same price forecast itself must be used. (T. Vol. 5 at 248-250)

Witness Petrie explained that in determining the rates it is proposing in this case, Dominion Energy North Carolina used the same Black-Scholes Model option pricing method to determine fuel hedging benefits that was proposed by the Public Staff in the 2014 biennial proceeding. (T. Vol. 5 at 221-222) He also noted that, while Dominion Energy North Carolina believes there are likely costs associated with integration of distributed solar generation, it did not include solar integration costs in its production cost modeling. (T. Vol. 5 at 222)

In his testimony, Public Staff witness Hinton found Dominion Energy North Carolina's reliance on price forecasts from ICF, the same source utilized for its 2016 IRP, along with the use of three-year forward prices before transitioning to a fundamental price forecast, to be reasonable. He also testified that he supports the use of forward prices as a component of developing a long-term price forecast, and that using five years of forward prices is reasonable and appropriate. He stated that Dominion's use of forward pricing for 18 months, then blending forward prices with a fundamental price forecast for the next 18 months to transition to a long-term forecast developed by ICF, is similar to the process it uses for forecasting coal prices and allows for a smooth transition to the long-term fundamental forecast. (T. Vol. 8 at 48-49; 52)

NCSEA witness Johnson found Dominion Energy North Carolina's method of blending forward prices with fundamental forecasts before transitioning to full fundamental prices to be reasonable. He recommended, however, that for purposes of calculating avoided energy cost rates in this case, Dominion Energy North Carolina should use either the March 2017 EIA forecast or the fundamental commodities forecast that Dominion Energy North Carolina used in preparing its 2016 IRP. He also asserted that the Utilities' natural gas price forecasts should approach the long-term gas price trend depicted in his testimony. (T. Vol. 7 at 254-256)

SACE witness Vitolo contended that Dominion Energy North Carolina's assumption of 85% availability for the additional QF added to the PROMOD "with QF" case in determining avoided energy costs resulted in a total annual avoided energy cost that will only be 85% of the total possible annual avoided energy cost. He stated that the $/MWh result will be appropriate if Dominion Energy North Carolina divides the resulting savings by the total MWh the QF operates in the simulation, but that the avoided energy rate will be 15% too low if Dominion Energy North Carolina divided the total dollar savings by 876,000 MWh (8,760 hours per year x 100 MW unit). He also suggested that Dominion Energy North Carolina should model its production costs based on the expected performance of QFs in its territory, rather than on base load generating unit performance. Witness Vitolo recommended that Dominion Energy North Carolina model the additional QF with 100% availability, asserting that this would allow the model to correctly count the value of QF generation on each hour of the year and ensure the model results analysis does not inadvertently only pay QFs for 85% of their avoided costs. (T. Vol. 7 at 61-63)

On rebuttal, witness Petrie noted the Public Staff's support for Dominion Energy North Carolina's fuel price forecasting approach, and disagreed with witness Johnson's suggestion that Dominion Energy North Carolina should use either the 2017 EIA forecast or the fundamental commodities forecast used to prepare its 2016 IRP for purposes of this case. He explained that, because the commodity prices for the 2016 IRP were developed by ICF in December 2015, Dominion Energy North Carolina used updated, October 2016 data for fuel and power prices in preparing its Initial Filing. He noted that, as standard offer prices are updated only every two years, QFs that establish an LEO late in the biennial period receive avoided cost rates that can be several years old by the time they commence operations, and that witness Johnson's proposal that Dominion Energy North Carolina base its avoided energy rates on forecasts that are an additional year older should therefore be rejected because it would exacerbate this disparity between contracted rates and actual avoided costs. Witness Petrie advised that using the 2017 EIA forecast for this purpose would also be inappropriate, as it would directly contradict the Commission's directives in the 2014 biennial proceeding and Dominion Energy North

Carolina's use of ICF-developed prices for its IRP and avoided cost purposes in compliance with those directives. (T. Vol. 5 at 249-250)

Witness Petrie also testified that witness Johnson's long-term natural gas price trend line does not reflect current natural gas market fundamentals, and that it appears to discount the fact that technology improvements continue to create production benefits resulting in reduced long-term natural gas prices. He explained that witness Johnson's gas price data lends too much weight to the years 1990-2008 when natural gas prices were rising and not enough weight to the downward trend in prices from 2009-2016. (T. Vol. 5 at 248-251)

In response to witness Vitolo, witness Petrie explained that no generator is available 100% of the time, regardless of whether the unit is utility-owned and regardless of the type of energy source. He explained further that Dominion Energy North Carolina's assumption of 85% availability in calculating standard offer avoided energy rates reflects the availability of a baseload unit, and that this approach is consistent with the theory behind the peaker method as it pertains to the calculation of avoided system energy costs from a typical QF. He cited the Commission's statement in the 2004 avoided cost proceeding that the peaker method theory is that, if the utility's generating system is operating at equilibrium (that is, at the optimal point), the cost of a peaker (a combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost, and that it will also equal the cost of a baseload plant. He noted that this modeling approach has been used by Dominion Energy North Carolina and accepted by the Commission for many years, including in the previous biennial proceeding. (T. Vol. 5 at 246-247)

Witness Petrie also disagreed with witness Vitolo's apparent concern that Dominion Energy North Carolina may be under-estimating the energy rates due to a mismatch between the PROMOD modelling and the energy rate calculation. Witness Petrie clarified that Dominion Energy North Carolina correctly divided the total dollar savings produced by the model by 744,600 MWh, consistent with the 85% availability, and that the system cost savings in the numerator was therefore consistent with the QF energy production in the denominator. (T. Vol. 5 at 248)

At the hearing, in response to questions from counsel for SACE, witness Petrie agreed that in using the PROMOD model to calculate avoided energy costs, Dominion Energy North Carolina modeled the "with QF" scenario using a 100 MW generator with zero production costs, and ran this scenario assuming some outages. He explained that when the 100 MW block of energy is added, the model shows how much the production cost declines by adding that block. He explained the block has 85% availability and that the 15% unavailability is spread evenly throughout all hours of the year, including on- and off-peak hours. He also confirmed his response to a discovery request that reiterated this explanation. (T. Vol. 6 at 60-61)

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that the inputs Dominion Energy North Carolina used to model its estimated avoided energy costs are reasonable and should be approved.

With respect to the fuel forecast Dominion Energy North Carolina used in its modelling, in the Phase 2 Order we determined that the Utilities should calculate avoided energy rates using natural gas and coal price forecasts that are developed in a manner consistent with those utilized in their 2014 IRPs. (Phase 2 Order at 7, 27) This directive therefore instructed the Utilities to develop fuel forecasts for avoided cost purposes based on an approach that is consistent with their IRPs. It did not require that the exact forecast that was used for the IRP be used for the avoided cost determination. Our intent in requiring the same forecast approach was to complement our preference that the inputs and assumptions between the IRP and avoided cost contexts be consistent. We did not, however, intend that a specific fuel forecast developed for an IRP be applied many months later to determine avoided cost when it would have become stale.

We therefore accept as reasonable and appropriate the fuel forecast developed by Dominion Energy North Carolina, which used the same price blending approach that was used in the forecast developed for its 2016 IRP, and which was supported by the Public Staff. We also therefore reject recommendations that Dominion Energy North Carolina should use the 2017 EIA forecast or the 2016 IRP forecast. As witness Petrie testified, using the 2017 EIA forecast—in addition to presenting the difficulty that it would require the Utilities to update their forecasts months after submitting their initial avoided cost filings pursuant to the normal schedule for these cases—would be inconsistent with the approach Dominion Energy North Carolina used to forecast fuel costs for its last IRP. As he also explained, requiring that the exact fuel forecast developed for that IRP be used in this case would force the use of an out-of-date forecast that Dominion Energy North Carolina appropriately updated, based on the same approach, for purposes of its proposal in this proceeding. We find that Dominion Energy North Carolina has appropriately calculated avoided cost rates that utilize a consistent methodology with the prior IRP while also using the best available current information.

We also agree with Dominion Energy North Carolina that the long-term natural gas price trend line offered by NCSEA witness Johnson does not reflect current natural gas market fundamentals. We believe that historical gas trends are of little value in the avoided cost context, which relies on forward-looking estimates. We note that FERC's *Order No. 69* establishes the principle that customers should be indifferent as to whether a utility purchases energy and capacity from a QF, buys those products from others, or produces them itself. We believe ratepayers will be indifferent when the avoided energy rates most closely reflect expected avoided energy costs, and conclude that Dominion Energy North Carolina's proposed fuel price estimates best meet that goal, since those estimates are as accurate as possible.

With regard to the input assumptions used in modelling its estimated avoided energy costs, we first note that the Public Staff supports Dominion Energy North Carolina's inputs and proposed avoided energy cost determinations. We also agree with Dominion Energy North Carolina that it reasonably modelled the "with QF" case with an assumed 85% availability, as it has done for the past several avoided cost cases. As witness Petrie explained, using an 85% availability in calculating standard offer avoided energy rates reflects the availability of a baseload unit. We agree that Dominion Energy North Carolina's approach is consistent with the theory behind the peaker method as it pertains to the calculation of avoided system energy costs, which we have described as being that, if the utility's generating system is operating at equilibrium (that is, at the optimal point), the cost of a peaker (a combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost, and that it will also equal the cost of a baseload plant.[15] We also note that, for purposes of this proceeding the production cost modeling and rate derivation process that Dominion Energy North Carolina has undertaken is intended to produce overall avoided energy costs and rates suitable for the standard offer, and not to produce a solar-specific avoided cost determination. Where therefore find Dominion Energy North Carolina's modeling of production costs in this proceeding to be reasonable and appropriate.

Finally, in the Phase 1 Order, the Commission concluded that there are hedging benefits associated with renewable generation, and that it is appropriate to recognize the hedging costs avoided due to energy purchases from QF generation in calculating avoided energy costs. (Phase 1 Order at 8, 42) In the Phase 2 Order, we found it appropriate that the Utilities should calculate these hedging benefits using the Black-Scholes Model or a similar method that values the added fuel price stability gained through each year of the term of the QF contract. (Phase 2 Order at 7, 30-31) Based on the record in this proceeding, the Commission concludes that Dominion Energy North Carolina has calculated avoided hedging costs in a manner consistent with the directives of the Phase 2 Order, using the Black-Scholes model, and therefore accepts as reasonable and appropriate Dominion Energy North Carolina's proposed hedging value of $0.14/MWh, which it assumed constant for all years of the Schedule 19-FP contract.

[15] *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2004*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 17, Docket No. E-100, Sub 100 (Sept. 29, 2005).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding is found in Dominion Energy North Carolina's Initial Filing, the testimony of Public Staff witness Hinton and NCSEA witness Johnson, and the rebuttal testimony of Dominion Energy North Carolina witness Petrie.

Dominion Energy North Carolina's Initial Filing reflected both the Option A and Option B rate options for the Schedule 19-FP standard contract, consistent with its standard rate schedules as approved in the previous two biennial proceedings.

Public Staff witness Hinton asked the Commission to revisit a proposal made by a NCSEA witness in Phase 1 of the 2014 biennial proceeding to define off-peak hours for solar QFs in a way that aligns with those facilities' diurnal profile, a change that was suggested in that case would increase off-peak energy rates. Witness Hinton acknowledged that the Commission rejected that proposal in that case, finding that it would isolate one potential benefit of solar generation while failing to account for any potential costs inherent in intermittent facilities. However, witness Hinton contended that this issue is more related to modeling or allocation than to solar integration, and asserted that from a customer perspective, solar energy provided during off-peak daylight hours has value that is not currently being fully recognized and properly allocated in off-peak avoided energy rates. (T. Vol. 8 at 77-79)

NCSEA witness Johnson claimed that Dominion Energy North Carolina's and Duke's proposals to retain the existing standard contract on- and off-peak hours designations, which he claimed are very broadly defined time periods, are "anomalous" given the utilities' concerns regarding the growing volume of solar energy being generated during certain hours of the day and times of the year. He asserted that stronger, more precise price signals, narrowly tailored to carefully identified hours during the summer and deep winter months, are needed. (T. Vol. 7 at 303-306)

In his rebuttal, Dominion Energy North Carolina witness Petrie testified that the definition of Option B on-peak hours includes fewer hours than Option A in order to include the utility's likely high-load hours and daytime hours when a solar facility is likely to generate. Witness Petrie noted that the Commission declined to accept the solar off-peak hours proposal in the 2014 biennial proceeding, recognizing that it would isolate one potential benefit of solar generation but fail to account for any potential costs inherent in intermittent resources. Witness Petrie testified that the same concerns about developing off-peak energy rates based on a solar profile exist today, and that this proposal should therefore again be rejected. He explained that if, as witness Hinton proposes, solar-specific rates are developed, the capacity rate should not reflect the full value of a peaker since PJM recognizes only 0-20% capacity value for intermittent facilities. He also stated that a solar-specific rate would need to account for additional costs, such as increased operating reserves, load deviation charges, and increased O&M on the utility's transmission and distribution system. He testified that Dominion Energy North Carolina continues to support the Option B hourly designation that was accepted in the 2014 biennial proceeding as more appropriately reflecting the benefits that a typical solar facility provides. He noted that nearly all solar QFs select Option B because it results in more revenue than Option A due to these QFs' expected generating profile. (T. Vol. 5 at 252-254)

Witness Petrie also noted that Dominion Energy North Carolina continues to offer Schedule 19-LMP, which precisely matches the generation profile of a solar QF with hourly market prices. He explained that the LMP-based rate schedule provides better price signals and additional granularity, should a solar QF want those benefits. (T. Vol. 5 at 254)

Witness Petrie testified that witness Johnson's assertion that utilities should provide better price signals was inconsistent with the positions witness Johnson took in this case regarding Dominion Energy North Carolina's proposed changes to the standard contract. Witness Petrie explained that all of the elements of the standard contract that witness Johnson supports—the 5 MW size threshold, the 15-year fixed pricing term, no locational pricing adjustment, payment for capacity when no capacity is needed, and the use of outdated pricing—contradict the goal of providing more precise price signals to QFs. (T. Vol. 5 at 254-255)

Witness Petrie concluded that including Option A, Option B, and Schedule 19-LMP in Dominion Energy North Carolina's standard offer provides small QFs with sufficient optionality to align avoided cost payments with their expected generation profile. He testified that, in addition, Dominion Energy North Carolina's proposal to move more QFs toward non-standard contracts by reducing the size threshold for the standard offer will allow QFs to obtain more precise price signals, because the rates will more closely align with the LEOs, and the prices can be adjusted to the timing and location of each QF. (T. Vol. 5 at 254-255)

<u>DISCUSSION AND CONCLUSIONS</u>

In the Phase 1 Order, we concluded that a similar proposal to establish solar-specific rates "isolates one potential benefit of solar generation, but fails to account for any of the potential costs inherent in such intermittent resources." We concluded that we "[found] it difficult to square such an unbalanced approach with PURPA." (Phase 1 Order at 62) We still believe that it would be inappropriate to define solar off-peak hours in a way that captures the benefit that solar energy offers by producing, on sunny days, power during high value, daytime off-peak hours, without considering the limitations of this intermittent resource and the additional costs associated with that intermittency. The therefore decline to accept the proposal to establish solar-specific off-peak energy rates in this proceeding.

We agree that Dominion Energy North Carolina's inclusion of Option A, Option B, and Schedule 19-LMP in its standard offer provides small QFs with sufficient optionality to align the contract rates with their expected generation profile position since, with these options, a QF can choose that rate schedule or Option that best suits its desire for price signals and granularity. In addition, we acknowledge that the other modifications that Dominion Energy North Carolina has proposed, which we address elsewhere in this Order, do offer more precise price signals to QFs, because they will allow rates to more closely align with LEOs, and prices to be adjusted based on the timing and location of each QF.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding is found in Dominion Energy North Carolina's Initial Filing, the testimony of Dominion Energy North Carolina witnesses Gaskill and Petrie, and the testimony of Public Staff witness Hinton and NCSEA witness Johnson.

Dominion Energy North Carolina's Initial Filing and the direct testimony of Dominion Energy North Carolina witnesses Gaskill and Petrie explained that LMPs reflect the value of energy at specific locations, or nodes, on the grid. As a result, areas that need additional generation to meet load will realize higher LMPs, which provide incentive for generation to locate in that place, while conversely, areas where generation is not valuable due to congestion or losses will realize lower LMPs. (T. Vol. 5 at 152, 218)

In his direct testimony, Dominion Energy North Carolina witness Petrie explained that power price inputs to and outputs from the PROMOD model Dominion Energy North Carolina uses to calculate avoided energy costs are expressed at the DOM Zone level, not at the nodal (local) level. He noted that the DOM Zone is an aggregate pricing point in the PJM energy market, and represents the average of LMPs of all nodes within the DOM Zone. Witness Petrie offered data, calculated using the average day-ahead LMPs at six North Carolina nodes selected due to their geographic diversity and proximity to QF development, showing that on-peak energy prices for Option B were 4.4% lower in Dominion Energy North Carolina's North Carolina service area than in the DOM Zone during the 2014-2016 time period, and 4.8% lower during off-peak periods. Energy prices for Option A were 4.7% lower during both on- and off-peak periods during this time. He testified that this LMP disparity is typical for grid locations with an oversupply of generation relative to customer demand. He stated that, all things being equal, Dominion Energy North Carolina's North Carolina LMPs are likely to be even lower in the future as additional distributed solar comes onto its system, leading to additional losses and congestion issues. (T. Vol. 5 at 218-220)

Witness Petrie explained that to account for this difference, Dominion Energy North Carolina adjusted the PROMOD model results to reflect the locational value of energy for QF deliveries in the North Carolina service area to ensure that the avoided energy rates Dominion Energy North Carolina and its customers pay are as accurate as possible. The adjustment reduced Option B on-peak rates by 4.4% and off-peak rates by 4.8%, and reduced Option A on- and off-peak rates by 4.7%, consistent with the historical data. (T. Vol. 5 at 219-221)

In his direct testimony, witness Gaskill explained that, while Dominion Energy North Carolina's fuel rates are based on the total system cost of energy, its system cost of energy is fundamentally derived from the LMPs where the load and generation are located. He explained that Dominion Energy North Carolina's total system energy cost is equal to the net of (1) the cost to supply load, and (2) generation energy revenues and costs. He demonstrated through several examples that, if additional generation is added (or load is reduced) in a location with low LMPs, it has less effect on lowering net system costs than generation that is added to a location with high LMPs. He testified that the avoided cost of added generation or load reduction is equal to the LMP at the bus where the generation or load reduction occurs. (T. Vol. 5 at 153-155)

Witness Gaskill also explained that lower LMPs indicate that additional generation in this area is less valuable than generation in other areas of the DOM Zone, and that the discounted value of generation in this area must therefore be incorporated into the forecasted avoided energy price, because that is the actual value PJM gives to this generation. He stated that Dominion Energy North Carolina's proposal to adjust avoided energy rates to reflect the locational energy value of its North Carolina service area would result in rates that better reflect its actual avoided cost for QFs in this area. He testified that, if Dominion Energy North Carolina does not make this adjustment, customers will pay rates that exceed the marginal energy costs that QFs in its North Carolina service area actually avoid. (T. Vol. 5 at 143, 152)

Finally, witness Gaskill testified that Dominion Energy North Carolina's proposed LMP adjustment is consistent with the peaker method, because the underlying theory behind the peaker method is that the long-run avoided energy cost is equal to the marginal costs of the utility's system in each hour and, as shown by his example, the LMP where the generation is located directly translates into the marginal cost avoided for the utility system. (T. Vol. 5 at 156)

In his testimony, Public Staff witness Hinton found Dominion Energy North Carolina's LMP adjustment proposal to be reasonable. He noted that Dominion Energy North Carolina provided support showing that the LMPs for North Carolina nodes have been consistently lower than the DOM Zone average LMPs. He recognized that the PROMOD model does not currently allow for calculation of energy rates at the nodal level and, as such, concluded that it is reasonable for Dominion Energy North Carolina to amend its avoided energy costs to reflect the lower LMPs in the North Carolina service area as compared to the DOM Zone average. (T. Vol. 8 at 76-77)

In his testimony, NCSEA witness Johnson stated that he did not object to using LMP data to help refine QF rates conceptually, and that LMPs are potentially relevant to the issue of how QF pricing signals can be best improved in order to encourage QFs to locate where they provide the most value. He opined, however, that more information and analysis is required in order to evaluate the LMP adjustment proposal, including its policy implications, the merits of the specific adjustment calculations, and the potential need for additional granularity. Witness Johnson suggested several issues that he considered need investigation in order to accept the proposal, which focused on the underlying factors of the LMP price differential, the size and stability over time of the LMP variations, whether to average the LMP differential across Dominion Energy North Carolina's North Carolina service area, and the impact of additional QF generation on LMPs at local buses and on the differential with DOM Zone LMPs. (T. Vol. 7 at 286-289)

On rebuttal, witness Gaskill testified that the evidence provided by Dominion Energy North Carolina through direct testimony and discovery substantially addresses witness Johnson's concerns. He cited witness Petrie's data showing that North Carolina LMPs have been lower than DOM Zone LMPs over the past three years and that this discrepancy has remained relatively stable. He explained that LMPs reflect the underlying supply and demand across the system—generally speaking, as supply increases, LMPs decrease, and if demand increases, LMPs increase. He noted that LMPs can be different from one location to another due to local congestion and marginal losses, and that as more generation is added in a location where it is not needed, the congestion and marginal losses costs increase, reflecting the re-dispatch cost to enable this generation to flow to locations on the transmission grid where it is needed to serve load. He offered a rebuttal exhibit with data showing the congestion and marginal loss components of the North Carolina nodes and the DOM Zone, including on-peak congestion between the two locations during 2016, of $1.84/MWh, and explained that the lower North Carolina LMPs reflect those congestion and loss components. He noted that, with approximately 500 MW of solar QF generation capacity under contract with Dominion Energy North Carolina, and assuming a 25% capacity factor, this congestion equates to approximately $2 million per year in congestion cost attributed to these QFs. This added cost to Dominion Energy North Carolina demonstrates, he stated, the importance of using LMPs that are associated with the locations where QFs are generating to correctly calculate avoided cost rates. (T. Vol. 5 at 194-197)

Specific to North Carolina, witness Gaskill noted further that, as more generation is added relative to load, the likely result will be a widening of the gap between the North Carolina and DOM Zone LMPs. He reiterated that this means that if additional generation is added (or load is reduced) in a location with already low LMPs (like North Carolina), net system costs are not lowered as much as if generation is added (or load reduced) in a location with high LMPs. (T. Vol. 5 at 194-195)

With respect to NCSEA witness Johnson's suggestion that pricing signals be provided on a more granular basis, witness Gaskill noted that the ability to provide more granular pricing signals and more timely avoided cost rates is a significant reason Dominion Energy North Carolina made this and other proposals in this case. He also noted that, by necessity, the standard contract offers a single price and contract that is available to all "small" QFs. As a result, Dominion Energy North Carolina must average LMPs across its North Carolina service area to arrive at an appropriate cost for the average QF, which it accomplished by averaging the LMPs of the six nodes, and factoring the difference between these average North Carolina LMPs and the DOM Zone LMP into the projected avoided energy costs contained in its filing. (T. Vol. 5 at 195) Conversely, witness Gaskill testified, negotiated contracts allow Dominion Energy North Carolina to evaluate LMPs at the specific location where the QF plans to interconnect at a much more granular level. He noted that reducing the standard offer size threshold to 1

MW would allow for more projects, and larger projects in particular, to receive individualized evaluation of LMPs that is not available under the standard offer. (T. Vol. 5 at 195-196)

In conclusion, witness Gaskill testified that the LMP at the node where a QF interconnects equates to Dominion Energy North Carolina's, and its customers,' actual avoided energy cost at that location. Since QFs subject to this proceeding will interconnect in the North Carolina service area, the LMP adjustment proposal aligns this QF generation with the market energy prices that it is expected to avoid. Therefore the proposal, combined with Dominion Energy North Carolina's other proposed changes to the standard offer, can benefit non-standard QFs by providing a better price signal and location incentive, as well as lower the risk that customers will pay rates that exceed Dominion Energy North Carolina's actual avoided costs in North Carolina. (T. Vol. 5 at 196)

At the hearing in response to questions from counsel for NCSEA, witness Petrie testified that some of the proposals Dominion Energy North Carolina has made in this proceeding would allow it more discretion with regard to large, non-standard QFs. Witness Gaskill added that Dominion Energy North Carolina's intention with the LMP adjustment proposal—as well as its proposal to eliminate the line loss adder discussed below—is to allow avoided cost rates to better reflect the actual locational value of new solar QFs on its North Carolina system. He clarified that while, for the standard offer, Dominion Energy North Carolina adjusted avoided energy rates to account for the difference between average LMPs across its North Carolina territory and DOM Zone LMPs, for a non-standard QF, Dominion Energy North Carolina can evaluate the LMPs at the location to which the QF plans to locate and, if LMPs at that location are comparable to the DOM Zone, not make the adjustment. (T. Vol. 6 at 37-38)

In response to cross by the Attorney General's office, witness Gaskill explained that LMPs represent the marginal cost to serve incremental load at a particular location. If 1 MW of load is added at that location, the LMP takes into account congestion on the system, marginal losses, and other factors to determine the cost to serve that additional MW. (T. Vol. 6 at 62-63)

On redirect, witness Gaskill explained that Dominion Energy North Carolina's system avoided costs at a particular location are represented by the actual marginal avoided system cost of additional generation, or load reduction, at the location where power is interjected onto the system. He testified that, in order to determine an average avoided cost for the standard offer, the LMP adjustment addresses the fact that PROMOD does not have the granularity to determine avoided costs at a particular location, such as reflecting transmission constraints at that location, by adjusting the avoided cost that the PROMOD model produces without considering intra-zonal congestion and losses to account for that difference. The LMP adjustment therefore produces the actual marginal system cost that a QF is avoiding. Witness Gaskill reiterated that, for non-standard QFs, Dominion Energy North Carolina can evaluate the LMP difference between that location and the DOM Zone to arrive at a precise price signal. (T. Vol. 6 at 84-85, 93-94)

<u>DISCUSSION AND CONCLUSIONS</u>

Based on the record in this proceeding, the Commission concludes that Dominion Energy North Carolina's proposal to adjust its avoided energy cost rates to account for the lower locational value of generation in its North Carolina service area as compared to

DOM Zone LMPs overall is reasonable and appropriate. Dominion Energy North Carolina's testimony, which no party contradicted, explains that, because they are produced on a DOM Zone basis, the avoided cost estimates produced by its production cost model do not reflect the value of energy located in North Carolina. Dominion Energy North Carolina also offered uncontroverted evidence, based on a reasonable and representative sample of nodes in its North Carolina service area, of the average disparity between DOM Zone LMP and North Carolina LMPs, which also shows the consistency of this differential in recent years.

We find persuasive Dominion Energy North Carolina's testimony that LMPs reflect the underlying supply and demand, and associated local congestion and marginal losses, across the system—generally speaking, as supply increases, LMPs decrease, and if demand increases, LMPs increase—and that the avoided cost of added generation or load reduction is equal to the LMP at the location where the generation or load reduction occurs. We are also persuaded by witness Gaskill's testimony explaining that the utility's marginal system cost of energy, which is the measure of avoided energy cost under the peaker method, is fundamentally derived from the LMPs associated with the location of load and generation. We recognize that as more generation is added to Dominion Energy North Carolina's North Carolina service area, a location that is saturated with narrowly concentrated distributed generation, the congestion and marginal losses costs increase, reflecting the re-dispatch cost to enable this generation to "flow" to locations where it is needed to serve load. This result is demonstrated by witness Gaskill's rebuttal exhibit, which shows on-peak congestion between Dominion Energy North Carolina's North Carolina nodes and the DOM Zone during 2016 of $1.84/MWh, which he estimates would result in $2 million annually in congestion costs for North Carolina QFs under contract. We agree that such significant added cost to Dominion Energy North Carolina's customers supports using the LMPs associated with the locations where QFs are generating to correctly calculate avoided cost rates. In addition, we are persuaded by Dominion Energy North Carolina's testimony that as more generation is added to this area relative to load, the disparity between North Carolina LMPs and DOM Zone LMP is likely to increase.

We note that the Public Staff supports Dominion Energy North Carolina's proposal, citing the data showing that the LMPs for North Carolina nodes have been consistently lower than the DOM Zone average LMPs. We note also that NCSEA witness Johnson agrees with the principle of reflecting local LMPs in avoided cost pricing, and agree with Dominion Energy North Carolina witness Gaskill that witness Johnson's proposed questions are substantially addressed by Dominion Energy North Carolina's proposal.

We conclude that Dominion Energy North Carolina's proposed adjustment to its avoided energy rates to reflect the locational value of the QF generation on its North Carolina system will allow those rates to better reflect its actual avoided system energy cost. We agree that, without this adjustment, Dominion Energy North Carolina and its customers will pay avoided energy rates that exceed its actual avoided energy costs, which would violate the customer indifference standard, in contravention of PURPA and FERC's implementing regulations. Based on the record in this proceeding, we therefore conclude that Dominion Energy North Carolina's proposed LMP adjustment to avoided energy cost rates should be approved. As noted above, Dominion Energy North Carolina shall reflect this adjustment in its Schedule 19-LMP compliance filing, using the LMP for the node located closest to the QF.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding is found in Dominion Energy North Carolina's Initial Filing, and the testimony of Dominion Energy North Carolina witness Gaskill, Public Staff witness Metz, SACE witness Vitolo, and NCSEA witness Johnson.

In its Initial Filing, Dominion Energy North Carolina proposed to eliminate the 3% adder to avoided energy rates that it has in recent years included to reflect the line loss costs assumed to be avoided by QF generation. Dominion Energy North Carolina explained that it is no longer avoiding line losses from additional distributed solar generation in North Carolina.

In his direct testimony, Dominion Energy North Carolina witness Gaskill provided additional support for this proposal. He explained that, when deployed effectively, distributed solar generation can avoid line losses, because when load on a particular circuit exceeds the generation interconnected to that circuit, solar or other generation at that location can often directly serve the load on that circuit and avoid transmission and transformer losses that would otherwise be associated with serving that load. He explained that the 3% adder was established under the assumption that QF distributed generation would be less than load on interconnected circuits, thereby permitting line losses arising from centrally-located generation to be reduced or eliminated. (T. Vol. 5 at 149)

Witness Gaskill testified that this assumption is no longer true. He explained that losses are generally only avoided when the substation load exceeds the local distributed generation on a substation bus. Otherwise, he stated, excess generation flows in reverse, or "backflows," onto the transmission grid to travel to serve load on a different circuit. In those cases, an increase in system line losses can actually occur, since the distributed generation must pass through two transformers (distribution to transmission to distribution) to reach the load that needs it. He stated that the volume of distributed solar generation on the North Carolina portion of Dominion Energy North Carolina's system has reached the point that it either is or will soon exceed the load requirement on most circuits, and that, when that happens, backflow occurs. He explained further that, when backflow occurs, many of the benefits and avoided costs attributed to distributed generation—scalability, mobility, and resulting reduced congestion and improved reliability—are lost. In particular, no line losses are avoided. (T. Vol. 5 at 139-140, 149-150)

Witness Gaskill presented data showing that backflow already occurs most of the time on some of Dominion Energy North Carolina's North Carolina substations and part of the time on other substations. Specifically, he offered data showing hourly load flow from September 2015 through September 2016 on Dominion Energy North Carolina's 33 distribution transformers that have interconnected distributed solar facilities. That data shows that 11 of those transformers are experiencing a predominantly constant backflow, indicating that the energy delivered from the distributed generation connected at these substations exceeds the load at those locations. Of the remaining 22 transformers, 18 are "neutral," meaning they either have a mix of forward and reverse flows or that there is only a small amount of excess load remaining, such that the interconnection of additional distributed solar at these transformers will tip the scales, resulting in power backflow, and not result in additional line loss savings at these locations. Only four transformers still showed a clear margin of load over currently interconnected distributed solar generation and, thus, the ability to host additional distributed solar without resulting in backflow. Witness Gaskill noted, however, that the addition of just one or two more 5-MW projects at these locations will eliminate this margin. He also noted that the data did not include distributed solar generation that commenced operations since September 2016, or the remaining approximate 600 MW of distributed solar generation in Dominion Energy North Carolina's interconnection queue that has not yet commenced operations. He testified that, when this generation is connected, the backflow on Dominion Energy North Carolina's substations will increase substantially. (T. Vol. 5 at 139, 149-151)

In light of the foregoing, witness Gaskill recommended that the 3% line loss adder should be eliminated for future QFs eligible for the standard offer. Without this change, he stated, customers will pay for losses that are not actually avoided. He noted that the data presented shows that customers are in many cases already paying for a loss adder under 2012 and 2014 biennial period contracts where no actual losses are being avoided. He argued that, while QFs already receiving the line loss adder may continue to receive it as specified in their contracts, future QFs should not be paid for losses that are not actually avoided. Witness Gaskill clarified that, for QFs not eligible for the standard offer, Dominion Energy North Carolina may calculate project-specific loss percentages, either positive or negative, depending on each project's specific interconnection location. (T. Vol. 5 at 149-151)

In his testimony, Public Staff witness Metz explained that the line loss factor first appeared in Dominion Energy North Carolina's avoided cost rate schedules in the 1987 avoided cost proceeding (Docket No. E-100, Sub 53), and that the rate was increased from 2.7% to 3% in the 2008 avoided cost proceeding (Docket No. E-100, Sub 117), at which level it has remained. He agreed that Dominion Energy North Carolina has demonstrated that its North Carolina grid is experiencing reverse power flows onto its transmission system from distributed generation, and that several of its substations already experience reverse flows. Witness Metz testified that, in the next few years as more distributed generation is interconnected to the Dominion Energy North Carolina grid, those loss reductions will continue. Witness Metz concluded that it is no longer appropriate to include a line loss adder in the avoided cost rate schedules when line losses will continue to diminish as more distributed solar is interconnected. (T. Vol. 8 at 130-131)

In his testimony, SACE witness Vitolo disagreed with Dominion Energy North Carolina's line loss analysis. Witness Vitolo agreed that increasing backflow from a substation that is already backflowing will not necessarily result in line loss avoidance at that specific time, but contended that, to the extent that a substation receives positive flow from the transmission system at any half-hour, an operating local distribution generator will avoid transmission line losses at that time. He asserted that as long as there are hours in a year when the transmission grid sees a net reduction of total demand, there will be line loss avoidance. Witness Vitolo contended that based on his own analysis of power flows at the 33 Dominion Energy North Carolina transformers, only one of those transformers showed a majority of half-hours with backflow. He opined that each of the other 10 substations labeled "negative" in Dominion Energy North Carolina's analysis experienced positive flow during most of their hours, and claimed that line losses would be avoided with additional solar generation added to all but one of the substations. Witness Vitolo claimed based on his analysis that eliminating the line loss adder would be inappropriate. He recommended that the Commission direct Dominion Energy North Carolina to calculate line loss avoidance with enough granularity to compensate renewable QFs for the value they provide in avoiding line loss and that, if such calculations are not feasible, it should continue to apply the 3% line loss adder. (T. Vol. 7 at 57-60)

NCSEA witness Johnson acknowledged in his testimony that backflow is occurring on Dominion Energy North Carolina's North Carolina system and that, in cases where backflow is occurring, line loss costs are not being avoided—a situation he termed "unfortunate," as costs that could be avoided are not being avoided. Witness Johnson asserted, however, that QFs rates have historically not included all of the avoided costs of distributed solar generation. (T. Vol. 7 at 274)

On rebuttal, Dominion Energy North Carolina witness Gaskill emphasized witness Metz's recognition of the forward-looking nature of this proceeding. He explained that, while many Dominion Energy North Carolina substations already realize significant reverse flow, any avoided line loss that remains at this point will continue to diminish in the future as additional distributed generation is interconnected. He emphasized that it is inappropriate to continue to pay for avoided line losses when the evidence is clear that the typical QF that signs a standard contract pursuant to this proceeding will likely not avoid any line losses. (T. Vol. 5 at 187-188)

Witness Gaskill testified that witness Vitolo's claim that only one of the 33 transformers experienced backflow during a majority of the time was incorrect. He explained that witness Vitolo's analysis included hours, including nighttime hours, when no solar QF generation would be producing. He also noted that witness Vitolo did not account for the fact that QF generation was incrementally added over the course of the year, which explains why the data would show more hours with backflow late in the year than early in the year, and did not recognize that the focus should be the state of the flow as it exists today and will exist in the future. He presented an example of one transformer at which reverse flow clearly increased at the point in time at which new generation was added, such that by the end of the time period studied, that transformer was experiencing reverse flow during nearly all daylight hours. Witness Gaskill also noted that, since the line flows presented in his direct exhibit only accounted for distributed generation that was operational at that time—293 MW as of September 2016—considering that the capacity of projects with PPAs or LEOs that have not yet come line exceeds 600 MW, the flows presented in the exhibit included only approximately half of the QF generation that has committed to sell to Dominion Energy North Carolina. He stated that many of the transformers identified as "neutral" or "positive" in his exhibit will soon experience predominately reverse flow as these additional QFs commence operations. (T. Vol. 5 at 188-191)

Finally, witness Gaskill explained that because in this proceeding Dominion Energy North Carolina is proposing rates and terms for the standard offer, it must derive a rate that applies to the average QF all across its North Carolina service area. As the amount of QF generation committed to Dominion Energy North Carolina already exceeds average on-peak load, the average QF going forward will not avoid additional line losses and will, in some cases, add to such losses. Since the avoided cost rates set in this case are forward-looking, the data clearly shows that most QFs subject to these rates will not avoid additional line losses. (T. Vol. 5 at 191-192)

In response to witness Johnson's testimony, witness Gaskill noted that Dominion Energy North Carolina has incorporated in its avoided cost rates those avoided costs that are reasonably known and quantifiable, including for avoided energy, capacity, line losses, and congestion. He explained that it is only now, in the absence of those benefits as QF generation has exceeded load and those benefits are reduced or eliminated, that Dominion Energy North Carolina has proposed to reduce or eliminate the associated costs from its standard avoided cost rates. He noted that Dominion Energy North Carolina shares Public Staff witness Hinton's concern regarding the uncertainty of integration costs, but since its integration costs studies have not yet quantified those costs, it has not proposed to include any integration costs into its avoided cost rates at this time. (T. Vol. 5 at 187-193)

At the hearing, witness Gaskill testified in response to questioning by counsel for NCSEA that, with respect to QFs not eligible for the standard offer, Dominion Energy North Carolina can evaluate the line loss characteristics of a specific circuit to which a QF plans to interconnect, and model that location with and without the additional generation to estimate the difference in line loss and determine whether avoided line loss should be reflected in the rate. (T. Vol. 6 at 37-38)

In response to questioning by counsel for SACE, witness Gaskill explained that line losses are avoided when a distribution level QF allows the utility to avoid transmitting generation across the transmission line, through the transformer to the load. He testified that if the QF does not serve load on that circuit, however, it reverse flows, and line losses are not avoided and may in fact increase. He explained that on Dominion Energy North Carolina's North Carolina system, the majority of circuits where QFs are interconnecting either are or will soon experience reverse flow, such that any line loss avoidance for new QFs will be zero or even negative, meaning the QF is actually contributing to, rather than avoiding, line losses. He opined that it would require a large amount of load growth in a short period of time for QFs that will interconnect in Dominion's service area under this proceeding to avoid line losses, and that he did not foresee that occurring. He confirmed that part of a discovery response, which he did not prepare, stated that Dominion Energy North Carolina has not quantified system losses associated with QFs in its North Carolina territory during times when backflow was and was not occurring over the past two years. He clarified that, as the purpose of the standard offer is to apply to all small QFs, Dominion Energy North Carolina has decided to consider the average across its North Carolina system to be zero, even though it is likely that the growing QF solar generation may actually be adding to line losses. He explained that this cannot be a QF-specific determination, since it is for the standard offer projects. (T. Vol. 6 at 52-56)

On redirect, witness Gaskill presented examples of transformer data from his line loss exhibit. He examined one transformer that he had labeled as "positive," meaning that generally load was being offset by generation at that location, and noted that that location had 10-15 MW of load, with another 13 MW of new generation in the queue to come online. He explained that once that new generation interconnects, the flow will shift to "neutral" at that location, because the interconnected generation will, when producing, offset the load at that location. He explained further that any additional generation interconnected at that location would not avoid any line losses, because all potential avoided line loss is being covered by the existing to soon-to-be interconnected generation at that transformer. (T. Vol. 6 at 85-89)

In another example, witness Gaskill explained how the Whitakers substation data shows positive load flow during nighttime hours when a solar facility does not generate, but reverse flow when the facility generates during daytime hours. He noted that where a location already sees reverse flow from negative load flow, adding more generation to that location will only increase the reverse flow. He testified that Dominion Energy North Carolina knows how much generation is in line to be constructed and begin operations, and that once that generation comes online, the vast majority of its substations will indicate predominantly reverse flow when that generation is producing. He testified that, for that reason, Dominion Energy North Carolina has concluded that across its North Carolina service territory, any additional generation at these locations will not on average avoid line loss, and most locations will incur additional line losses due to increased reverse flow. He noted that, despite its expectation that additional line losses will be incurred, Dominion Energy North Carolina settled on zero avoided line loss for purposes of its standard avoided cost rates. (T. Vol. 6 at 85-89)

During cross examination, witness Vitolo agreed that the purpose of the line loss adder has been to compensate QFs for line losses that their facilities allow utilities to avoid. (T. Vol. 7 at 77) He also agreed that, according to FERC, paying for line loss is appropriate where the utility avoids line loss costs it would have incurred but for the QF being at that location. (T. Vol. 7 at 79) He agreed further that solar QFs can avoid line loss by meeting at least in part the requirements of the load at a particular location, so that the electricity does not need to travel elsewhere on the system. (T. Vol. 7 at 79) He recognized that backflow can occur and that, depending on the details of the substation and the flow on the transmission grid, increasing backflow from a substation already backflowing will not necessarily result in line loss avoidance at that time. (T. Vol. 7 at 79-80) He admitted that in his own line loss analysis, while he removed data points for which the power flow registered as zero, and started his analysis at each substation at the point in time at which backflow started to occur, he did not remove any data points corresponding to non-daylight hours. (T. Vol. 7 at 92-95) He agreed that the vast majority of QFs coming online on Dominion Energy North Carolina's North Carolina system are solar QFs, and that a substantial number of the next 100 QFs to come online will be solar. (T. Vol. 7 at 96) On cross and redirect, witness Vitolo testified that each of Dominion Energy North Carolina's substations would present a different picture than the others. (T. Vol. 7 at 84, 99) However, with respect to an example transformer about which Dominion Energy North Carolina counsel questioned him, he also agreed that there is a solar correlation associated with the times of day that the example transformer showed a negative power flow (i.e., the negative flow occurred during daylight hours), and he agreed that no negative power flows occurred after 6:00 pm on that day for that transformer. (T. Vol. 7 at 97-98)

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, the Commission concludes that Dominion Energy North Carolina's proposal to eliminate the 3% line loss adder from its avoided energy cost rates in this case is reasonable and appropriate and should be approved. As explained by witnesses for Dominion Energy North Carolina and others, it is clear that line losses are avoided when distributed generation can offset the load at a particular location, thereby reducing the flow of power required to travel from the transmission system to the distribution to serve that load and avoiding the line losses that would be associated with that power flow. Conversely, when the distributed generation connected at a particular location exceeds the load requirements at that location, upstream line losses are not actually avoided, because there is no local load being offset. In that case, the power must flow back onto the system, traveling through transformers and onto transmission lines, with the accompanying, and additional, line losses.

We find persuasive Dominion Energy North Carolina's analysis showing that the majority of its transformers to which QF generation is connected in North Carolina are experiencing reverse power flows during the hours of the day when solar generation would be expected to produce power. Since this analysis did not account for the substantial volume of distributed solar capacity that is currently moving through the interconnection queue or under construction, we agree with Dominion Energy North Carolina, and with the Public Staff, that, once this additional generation is added to these locations, reverse flows will increase, and line losses will likely increase, and not be avoided.

We do not find witness Vitolo's critique of Dominion Energy North Carolina's load flow analysis to be persuasive. Most importantly, we find it entirely unreasonable to count nighttime hours in an analysis of the impacts on power flows of generation facilities that rely on solar technology. By definition, solar generation does not produce power during nighttime hours. Including power flow data from the nighttime hours therefore skews the results in favor of a suggestion that these locations are almost all experiencing positive power flows (from the Dominion Energy North Carolina system to the load). We note that witness Vitolo agreed on cross-examination that the vast majority of QFs coming online on Dominion Energy North Carolina's North Carolina system are solar QFs. We also note that, while each of Dominion Energy North Carolina's substations would likely present a different picture than the others in terms of power flow and line loss, witness Vitolo agreed that, where a transformer shows negative power flows only during the daylight hours, there is a "solar correlation" to that phenomenon.

Moreover, while witness Vitolo did limit his analysis of each transformer to the period of time during which QF generation was located there (as opposed to looking at power flows that occurred prior to any QF generation being connected), he did not account for the subsequent increases in reverse flows that occurred at several transformers once *additional* facilities came online, as shown for example by the graphs provided in witness Gaskill's rebuttal testimony, which demonstrate the connection between the addition of incremental QF generation and the increased degree of reverse power flow.

With regard to witness Johnson's testimony that QFs rates have historically not included all of the avoided costs of distributed solar, we conclude that Dominion Energy North Carolina has indeed incorporated in its avoided cost rates those avoided costs that are reasonably known and quantifiable, and agree that now, as QF generation has exceeded local load and those benefits are reduced or eliminated, it is appropriate to reduce or eliminate those avoided costs from its standard avoided cost rates. Dominion Energy North Carolina has proceeded reasonably in this respect as well as in refraining from proposing to include any integration costs into its avoided cost rates at this time until its studies of the issue of integration costs have been able to quantify such costs, and in settling on a line loss factor of zero, rather than proposing to reflect the additional line loss that evidence suggests is already occurring in many locations on its North Carolina system.

Finally, we agree with Dominion Energy North Carolina that, since the goal of this proceeding is to establish standard rates and terms that will apply on a prospective basis, to QFs that established LEOs subsequent to November 15, 2016 and are otherwise eligible for the standard offer contract, the relevant considerations are the current overall load flow situation, which indicates that many of Dominion Energy North Carolina's transformers are experiencing significant periods of reverse flow, and the expected future situation that will develop once additional QF generators are constructed at these locations. We agree with Dominion Energy North Carolina and with the Public Staff that it is no longer appropriate to include a line loss adder in the standard avoided cost rate schedules when line losses will continue to diminish as more distributed solar is interconnected. We also agree that, without this change, customers will pay for losses that are not actually avoided, which is contrary to PURPA principles. We note that Dominion Energy North Carolina's customers are in many cases already paying for a loss adder under 2012 and 2014 biennial period contracts where no actual losses are avoided. We conclude that, while QFs already receiving the line loss adder may continue to receive it as specified in their contracts, eliminating the 3% line loss adder from Dominion Energy North Carolina's standard avoided energy rates in this proceeding will appropriately reflect the clear evidence that, on a prospective basis, most QFs locating in its North Carolina service area are no longer avoiding line losses due to the saturation of distribution level QFs relative to the load on Dominion Energy North Carolina's system. We note that, consistent with the proposals it has made in this proceeding to encourage developers to locate QFs where they can provide the most value, non-standard QFs may still receive credit for avoided line losses if it is determined based on their proposed location that their additional generation will offset Dominion Energy North Carolina load and therefore avoid line loss. For standard QFs, however, the proposal to eliminate the line loss adjustment is consistent with the "but for" principle of avoided cost, and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding is found in Dominion Energy North Carolina's Initial Filing, the testimony of Dominion Energy North Carolina witnesses Gaskill and Petrie, the testimony of Duke witnesses Bowman and Snider, Public Staff witness Hinton, SACE witness Vitolo, and NCSEA witness Johnson, and the entire record in this proceeding.

In its Initial Filing, Dominion Energy North Carolina proposed to include no payment for capacity with its standard offer avoided cost rates. Dominion Energy North Carolina explained that this proposal is appropriate because it does not have a near-term need for additional North Carolina capacity, and because its North Carolina service area is so saturated with distributed solar generation that additional QF generation will not incrementally reduce load or, as result, defer or avoid the need for future capacity. Consistent with this proposal, Dominion Energy North Carolina did not submit cost data pursuant to the peaker method or an allocation of capacity costs between the summer and winter seasons. Dominion Energy North Carolina noted that its current net capacity position is a change from the position it held during the 2014 biennial proceeding, at which time its most recent IRP did reflect a significant need for new capacity over the planning horizon, beginning as early as 2018. However, due to reductions in the load forecast, and the addition of new generation to its fleet, Dominion Energy North Carolina explained that the point in time at which it will need new capacity has moved several years into the future.

In his direct testimony, Dominion Energy North Carolina witness Gaskill stated that, even if it did have a near-term need for additional generation capacity in North Carolina, which it does not, additional distributed solar generation in this State beyond what is already under contract would not allow Dominion Energy North Carolina to avoid future capacity expansions. He noted that FERC has clarified that, while utilities may be obligated under PURPA to purchase from QFs, an avoided cost rate need not include payment for capacity where a QF does not allow the purchasing utility to avoid building or buying future capacity—that, when a utility's demand for capacity is zero, the cost for capacity may also be zero. He concluded that, because it will not avoid capacity need due to incremental distributed solar generation in North Carolina, a capacity rate of zero accurately reflects Dominion Energy North Carolina's actual avoided costs for QF contracts signed today. (T. Vol. 5 at 157-158).

In his direct testimony, Dominion Energy North Carolina witness Petrie discussed several factors in support of this proposal. First, witness Petrie explained that Dominion Energy North Carolina's 2016 IRP showed no capacity need until 2022 at the earliest, and that its preliminary updated load forecast as of December 2016 pushes that need for incremental capacity out to 2024. He also noted that the most recent PJM load forecast from January 2017 shows no need for capacity for Dominion Energy North Carolina until after the 2026 timeframe. (T. Vol. 5 at 222-225)

Additionally, witness Petrie confirmed that, even if a need for new capacity did exist within Dominion Energy North Carolina's current long-term planning horizon, because its North Carolina service area is saturated with distributed solar QF projects, any new distributed solar generation added going forward will have little to no peak load reducing effect on the system. He explained that new solar QFs are not effective substitutes for new dispatchable generation, such as a CT, unless they are located near areas with increasing load growth and where additional generation is needed to reduce congestion and improve reliability. This is not the case for solar QFs in Dominion Energy North Carolina's North Carolina territory. Witness Petrie also noted that, while previous QFs interconnecting at the distribution level acted as load reducers, therefore deferring the need for new capacity, this is no longer the case because distributed solar generation now exceeds load in the North Carolina service area, such that there is no more load to be offset. For similar reasons, he noted, additional distributed solar in this area will not improve overall system reliability, especially with regard to meeting wintertime peak demands. Considering all of these factors, witness Petrie concluded that Dominion Energy North Carolina cannot avoid building or buying capacity by purchasing from new distributed solar generation in its North Carolina service area. (T. Vol. 5 at 225-226)

Witness Petrie also testified that Dominion Energy North Carolina is considering the addition of aeroderivative CTs as quick-start, flexible units that can balance the system as more intermittent, non-dispatchable solar generation resources are added.

However, because these aeroderivative CTs have a higher installed cost than the large frame turbines that Dominion Energy North Carolina has built since the year 2000 (an estimated 67% more than other CTs), their addition will result in *increased* long-term capacity costs for customers. (T. Vol. 5 at 226-228)

Witness Petrie testified further that pricing for solar generation should reflect its lack of dispatchability and limited usefulness during system emergencies. He explained that FERC's rules list several factors that should be considered when determining avoided cost rates for QFs including, among other factors, the availability of a QF's energy or capacity, the utility's ability to dispatch the QF, the QF's expected or demonstrated reliability, and the usefulness of the QF's energy and capacity during system emergencies. Witness Petrie also noted his understanding of FERC's recent explanation that its rules permit state regulatory authorities to consider factors such as capacity availability, dispatchability, reliability, and the value of energy and capacity when determining avoided cost rates, and, based on these factors, to set lower rates for purchases from intermittent QFs than for purchases from firm QFs. (T. Vol. 5 at 228-229)

Witness Petrie also cited recent changes to PJM's capacity market rules as further evidence that additional distributed solar generation in Dominion Energy North Carolina's North Carolina service area is not the type of reliable capacity that would allow it to avoid capacity needs. He explained that these rule changes were intended to better reflect the changing resource mix in PJM, including the growing volume of intermittent generation, and to better align resource payments to performance. He noted that intermittent resources are particularly challenged under the new rules, as they can be subject to severe penalties for non-performance during summer and winter peak hours. He also pointed out that PJM training materials issued after FERC approved the new rules suggest that an acceptable offer for a 100 MW nameplate solar facility would be from 0 to 20 MW of firm capacity. He concluded that these changes demonstrate that solar capacity, as compared to the firm capacity of a dispatchable and reliable CT, is not capable of sustained, predictable operation during emergency conditions, and has limited value in the new PJM capacity market, from which Dominion Energy North Carolina's actual avoided costs are derived. (T. Vol. 5 at 229-230)

Witness Petrie also explained that Dominion Energy North Carolina, which has experienced winter peaks in two of the last three years, as well as PJM, have increased their focus on planning for winter reliability, the costs for which include procuring fuel supply backup, additional gas pipeline capacity, and improved winter testing and operations. He noted that the spikes in demand during periods of extreme cold over the last several years show the volatility of winter peak loads and the need for dispatchable generation on the system. He noted also that because solar generation output is near zero at 7 am on cold winter mornings when these system peaks occur, a CT is still required in the winter. (T. Vol. 5 at 231-232)

Finally, witness Petrie testified that the addition of large amounts of distributed solar resources is likely to shift the time of the summer peak to a later hour in the day, while not impacting the timing of the winter peak load due to their minimal output at that time. He noted that, when Dominion Energy North Carolina reaches the threshold of aggregate solar additions of about 1,000 MW across its North Carolina service area, the summer peak hour is expected to shift from 5 pm to 6 pm or later. Witness Petrie explained that, as the summer peak hour shifts later in the day, any additional solar generation produces less summer peak load reducing effect, and is thus less effective in deferring or avoiding the next required capacity resource, because solar output decreases in the later hours of the evening and, therefore, has lower capacity value. The marginal value of solar capacity therefore decreases as more solar generation is added to the system. (T. Vol. 5 at 232-233)

Witness Petrie concluded that Dominion Energy North Carolina's proposal to make no capacity payments to QFs receiving the standard offer accounts for the fact that, due to all of these factors, additional North Carolina QF solar resources will not allow it to defer or avoid capacity needs. This proposed modification would also, he stated, avoid burdening customers with avoided cost payments that exceed Dominion Energy North Carolina's actual avoided costs. (T. Vol. 5 at 233-234)

In her direct testimony, Duke witness Bowman introduced Duke's proposal that the capacity credits contained in DEC's and DEP's standard offer tariffs account for their respective relative need for generating capacity. She testified that customers should not be obligated to pay for capacity value in years in which the utilities have no capacity need. (T. Vol. 2 at 355) Duke witness Snider also testified in support of this proposal, stating that Duke's relative need for incremental generating capacity should be accounted for in calculating avoided capacity rates, and capacity value should not be ascribed for years prior to the first avoidable capacity need. The result would be that the QF receives a capacity rate that reflects a lower annual levelized payment to account for those initial years in which no avoidable capacity costs are included in the rate derivation. (T. Vol. 2 at 219-220)

Witness Bowman also discussed the Commission's previous evaluation of FERC's *Ketchikan* and *Hydrodynamics* decisions. She testified that in the Phase 1 Order, the Commission cited FERC's decision in *Hydrodynamics* as supportive of its determination that the Utilities should not include zeros in the early years when calculating avoided capacity rates. She explained that the *Hydrodynamics* decision, however, did not pertain to a utility's proposal to recognize a capacity value only in years where IRPs showed a need. Instead, *Hydrodynamics* concerned a utility-imposed 50 MW limit on installed capacity purchases from wind QFs. Upon review, FERC found that the cap on QF-provided capacity prevented certain wind QFs from receiving any fixed long-term compensation for capacity. Citing its decision in *Ketchikan*, FERC stated in *Hydrodvnamics* that avoided cost rates need not include the cost for capacity when the utility's demand or need for capacity is zero. FERC concluded, however, based upon the record before it, that the cap on installed capacity did not have "a clear relationship" to the utility's "actual demand" for capacity; therefore, the *Ketchikan* rationale did not apply. She stated that, in contrast, in this docket, Duke had not proposed to cap capacity purchases from certain solar QFs at an arbitrary level, but rather proposed to continue to purchase capacity, but to do so at rates that have a clear and direct relationship to Duke's actual capacity needs. As such, she testified, Duke's proposal is consistent with FERC's decisions in both *Ketchikan* and *Hydrodynamics*. (T. Vol. 2 at 357-358)

In his testimony, Public Staff witness Hinton disagreed with Dominion Energy North Carolina's proposal, noting that utility planning is performed on a system-wide rather than state-by-state basis. He contended that additional generation in North Carolina can help offset future system capacity costs and therefore the rate should not be set to zero for all years. (T. Vol. 8 at 34-35) Witness Hinton testified in support of Duke's proposal to limit capacity payments until a utility's IRP dictates a capacity need. He explained that, contrary to the Public Staff's position in prior proceedings, he believes that given the current circumstances, including the level of solar generation that has come online and the amount of solar generation in the interconnection queue, a departure from the traditional application of the peaker method is warranted. He opined that it is therefore appropriate for the Utilities to pay QFs for capacity only when additional capacity is needed on the system, and that restricting the payment until the IRP has established a capacity deficiency will minimize the overpayment risk to ratepayers, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market. (T. Vol. 8 at 29-30) At the hearing, while witness Hinton agreed that it is not his position in this case that a utility's short-term resource adequacy reduces the cost of future capacity additions, (T. Vol. 8 at 228), he continued to support the position that it is appropriate in this case for the Utilities to make a capacity payment to QFs only when additional capacity is needed on the system. (T. Vol. 8 at 226-227, 228-229)

SACE witness Vitolo also disagreed with Dominion Energy North Carolina's proposal, contending that PJM is a summer-peaking system and that the PJM wholesale capacity market has a surplus of capacity during winter months but market demand for summertime capacity. He claimed based on these assertions that, even with the "slight" generation capacity value offered by a solar QF in wintertime, solar QFs still allow Dominion Energy North Carolina to defer or avoid capacity related costs, as well as sell additional surplus generation capacity into the PJM capacity market. He opined that the peaker method does not require that the QF have operating properties that align with the utility's planned capacity addition, and that an important feature of this method is its ability to calculate avoided generation capacity cost regardless of the specifics of the utility's capacity expansion plan. He also asserted that the class average capacity value of 38% that PJM has specified for solar facilities exceeds the range of values presented by Dominion Energy North Carolina witness Petrie. (T. Vol. 7 at 49-51) Finally, he claimed that, due to the Commission's determination in the 2014 biennial proceeding that FERC's *Ketchikan* determination, because it was decided on the specific facts at issue in that case, does not apply in North Carolina avoided cost proceedings, the *Ketchikan* ruling cannot be used to support Dominion Energy North Carolina's capacity proposal. (T. Vol. 7 at 52)

While NCSEA witness Johnson focused primarily on Duke's capacity proposal, he asserted that using zeros for capacity rates is inconsistent with the fundamental goals of PURPA, and with the most appropriate interpretation of the concepts of incremental cost and avoided cost, as well as with the concept of ratepayer indifference and the prohibition against discrimination against QFs. He agreed with the Commission's decision from the 2014 biennial proceeding and recommended that it again reject proposals to use zeros for capacity credits in this docket. (T. Vol. 7 at 292-297)

On rebuttal, Dominion Energy North Carolina witness Gaskill noted that FERC's rules implementing PURPA define avoided costs as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from a QF, the utility would generate itself or purchase from another source. He stressed the importance of the "but for" language in that definition in the context of capacity payments, noting that it is not the case that, "but for" the distributed solar QFs on its North Carolina system, Dominion Energy North Carolina would purchase or self-supply capacity. He explained that previous QFs interconnecting at distribution level acted as load reducers and, by reducing Dominion Energy North Carolina's load obligation, deferred the need to buy or construct new capacity. Because distributed solar generation now exceeds load in this area, however, that is no longer the case. He explained that, for these reasons and those discussed by witness Petrie, there is no need for additional distributed solar in Dominion Energy North Carolina's North Carolina service area, and that because incremental distributed solar QF generation in North Carolina will not allow it to avoid capacity need, a zero capacity payment accurately reflects Dominion Energy North Carolina's actual avoided costs for QF contracts signed today. (T. Vol. 5 at 198-199)

Dominion Energy North Carolina witness Petrie testified on rebuttal that, in order for a new QF to avoid future capacity costs, there must be a need for capacity, and the QF must be of the type and location to actually avoid that need. He explained that, due to the factors outlined in his direct testimony, neither of these criteria are true for additional solar QFs in Dominion Energy North Carolina's North Carolina service area. In particular, he noted that because solar QF generation in this area now exceeds Dominion Energy North Carolina's average peak load, new distributed solar QFs interconnecting in North Carolina no longer reduce load, and therefore do not reduce Dominion Energy North Carolina's load obligation or defer new capacity needs. For the same reasons, witness Petrie testified in response to Public Staff witness Hinton that, while generation and transmission planning does occur on a system-wide basis, location matters for resource expansion planning, and that adding more intermittent generation to northeastern North Carolina, which is already saturated with this type of generation, will not allow Dominion Energy North Carolina to avoid or defer future capacity needs. Witness Petrie concluded that, given these considerations and the factors described in his direct testimony, the appropriate capacity rate for new QFs located in this area is zero cents per kWh for the duration of the standard offer contract. (T. Vol. 5 at 255-258)

Witness Petrie testified further that witness Vitolo's assertion that, as a PJM member, Dominion Energy North Carolina only has summer capacity needs is incorrect and oversimplified. He explained that the PJM capacity market reflects the need for capacity planning to meet both summer and winter peaks, since under its new capacity market rules, PJM generators must provide reliable capacity during all months of the year. He disagreed that PJM has a surplus of winter capacity, citing the shortage of available generation during the winter of 2014 that demonstrated the need for the new rules. He also explained that, since solar resources have little or no capacity to generate at the winter morning peak, they are subject to significant capacity performance penalties if they bid into this market, since under the new rules they are subject to the same financial penalties that apply to conventional fossil-fueled resources for non-performance on critical days. (T. Vol. 5 at 258-259)

Witness Petrie also explained that the 38% capacity value cited by witness Vitolo denotes capacity injection rights, not the market capacity value, of solar resources. He emphasized that, on a risk adjusted basis, the capacity credit of a solar resource offered into PJM's capacity market is in the nameplate capacity range of 0 to 20% (based on PJM's assumption that a typical solar facility may provide 38% in the summer, but only 2% in the winter). Whether a solar generator bids into the PJM market at 0 or 20%

depends on how much penalty risk the generator is willing to accept. He explained that this reduced capacity credit percentage, combined with the potential penalties, demonstrates that, from a reliability perspective, solar resources can only be counted on for a small portion, if any, of their nameplate capacity, and that continuing to pay new solar QFs rates for avoided capacity, when they do not defer or avoid any capacity need, results in an overpayment beyond Dominion Energy North Carolina's actual avoided costs. (T. Vol. 5 at 259-260)

Witness Petrie also addressed Duke's proposal to include zeros in the calculation of the capacity rates for the years where the utility does not have a capacity need. He stated that, in the event that the Commission declines to accept Dominion Energy North Carolina's proposal to set capacity rates to zero for the duration of the standard offer contract, Dominion Energy North Carolina would agree with Public Staff witness Hinton's conclusion that Duke's proposal is reasonable and appropriate. He explained that, while Duke's proposal would still result in Dominion Energy North Carolina overpaying QFs, it would come closer to valuing the capacity appropriately over the course of a long-term PPA than would paying a QF for capacity over the entire term, including for years in which there is no demonstrated need. (T. Vol. 5 at 262)

Witness Petrie agreed with witness Hinton that in the current circumstances it is appropriate for the Commission to reconsider this issue, since the traditional application of the peaker method is resulting in overpayment in excess of actual avoided costs and is not sending proper price signals to the market. He noted that there is historical precedent for the Commission allowing the utility to pay zero for capacity during the front years of a QF contract, citing orders issued in the 1994, 1996, and 1998 avoided cost proceedings in which the Commission recognized that, where no capacity costs are avoided, no capacity credit should be reflected in the capacity rate calculation. He stated that the evidence in this case, which shows that Dominion Energy North Carolina has no capacity need for the foreseeable future and that paying for capacity when it is not avoided results in overpayment risk for customers, is analogous to those proceedings. (T. Vol. 5 at 263-264)

Witness Petrie disagreed with witness Johnson that paying QFs for capacity only when the utility actually shows a capacity need discriminates against QFs. He explained that, as a regulated utility, Dominion Energy North Carolina has an obligation under the law to serve its customers reliably and at least cost. He explained further that North Carolina QFs cannot defer or avoid the need for new capacity because they do not reduce load on Dominion Energy North Carolina's system (i.e., they do not reduce the peak load forecast, which is the basis for the future capacity requirements). He testified that paying for capacity when it is not needed or avoided contradicts the PURPA requirement that the rates a utility pays for QF output should not exceed the utility's avoided costs. He also explained that, contrary to witness Johnson's assertion, the principle of ratepayer indifference is also violated if customers pay the QF for capacity that is not actually avoided, because those customers are paying for something they do not receive. He noted that the determination of avoided costs and rates to be made in this proceeding is not a theoretical exercise, but instead represents real customer costs. (T. Vol. 5 at 261, 264-265)

Finally, witness Petrie testified that, contrary to witness Vitolo's testimony, the circumstances of the *Ketchikan* case, in which he understood FERC to have found that if the utility does not have a demonstrated capacity need it should not be required to pay for incremental QF capacity, are similar to the current situation in North Carolina. He noted that as shown in *Ketchikan*, Dominion Energy North Carolina also currently has no near-term incremental capacity needs. He acknowledged that in the 2014 biennial proceeding, the Commission cited FERC's later *Hydrodynamics* decision in support of its determination in that docket that the Utilities should not include zeros for capacity in the early years when calculating avoided capacity rates. He explained that the situation in *Hydrodynamics* differed from the circumstances at issue in *Ketchikan* and those at issue in this proceeding, because it addressed a utility proposal to limit installed capacity purchases with no connection between that limit and the utility's own actual need. He noted that, in *Hydrodynamics*, FERC reiterated its earlier conclusion that when a utility's demand or need for capacity is zero, avoided cost rates need not include capacity cost. He stated that such is the case here, and therefore that the *Ketchikan* rationale does apply to this case and to Dominion Energy North Carolina's proposal. (T. Vol. 5 at 265)

In his rebuttal, Duke witness Snider testified that including capacity value in avoided cost rates that is not actually avoidable results in an overpayment by consumers in violation of PURPA. He explained that utilities select units for their resource plans based on what is the most economic resource option for consumers, and that a QF can only provide capacity value if there is an avoidable capital investment that can actually be deferred. He stated that consumers are harmed by paying for capacity that is not actually avoided. (T. Vol. 2 at 274-275)

At the hearing, Dominion Energy North Carolina witness Petrie clarified that it was not relevant that Dominion Energy North Carolina used the differential revenue requirement (DRR) method of determining avoided costs during the 1990s cases in which the Commission recognized that no capacity credit should be included where no capacity costs are avoided. He explained that, regardless of avoided cost methodology, if there is no demonstrated capacity need, the utility should not be required to pay for capacity. He agreed that all three traditional avoided cost methodologies have the same purpose: reasonably estimating the utility's future avoided cost. (T. Vol. 6 at 34-35)

Also at the hearing, Dominion Energy North Carolina witness Gaskill testified that the number of QF PPAs and related capacity that Dominion Energy North Carolina has entered into increased from 72 PPAs and 500 MW of capacity as of the date of his direct testimony to 76 PPAs and 521 MW of capacity as of the hearing date. Witness Gaskill also answered questions from NCSEA counsel comparing the amount of distributed solar generation on Dominion Energy North Carolina's North Carolina system as described in his testimony to the amount of solar generation either connected to its system or having an executed Interconnection Agreement that was identified in its February 1, 2017 interconnection queue report filed in Docket No. E-100, Sub 101A (and entered as NCSEA-DNCP Cross Exhibit 1). He clarified that the queue report is prepared by Dominion Energy North Carolina's interconnection team from which he operates separately. He explained, however, that the 435 MW of operational solar capacity noted in his testimony is consistent with the 345 MW of operational interconnected solar capacity reflected in the queue report, because the 435 MW total includes 90 MW of solar that is in the PJM wholesale interconnection queue, but is interconnecting to Dominion Energy North Carolina's distribution system. Similarly, he testified that the difference between his estimate of 363 MW in study phase as shown in

Figure 2 to his direct testimony, and the 282 MW designated as Project A, Project B, or "Subordinate" in the queue report, is also likely due to his Figure 2 including PJM queue projects. He also noted that the total MW reflected by the queue report as "connected" and "IA executed" projects—519 MW—is comparable with his updated testimony that Dominion Energy North Carolina has entered into PPAs for 521 MW of solar capacity. (T. Vol. 6 at 40-46)

In response to questions by counsel for SACE, witness Petrie testified that Dominion Energy North Carolina occasionally enters into contracts for capacity outside of QF agreements, and recently acquired replacement capacity related to the March 2017 deactivation of the Roanoke Valley Power facility (ROVA), some of which it filled through short-term capacity purchases in the PJM market. Witness Gaskill explained that the term of the contract for Dominion Energy North Carolina's purchases from this facility extended through mid-2019, but because the facility deactivated, Dominion Energy North Carolina was obligated to locate capacity to replace what that facility had committed through PJM's wholesale capacity market. He testified that Dominion Energy North Carolina is self-supplying the remainder of the capacity previously supplied by this facility. (T. Vol. 6 at 56-58)

On redirect, witness Gaskill further explained that, generally speaking, non-wholesale contracts, such as a contract for a QF selling under PURPA, would not be eligible to replace a capacity commitment by being bid directly into the PJM wholesale capacity market, because they are not participants in that market. Specifically as to the ROVA facility, he explained that because that facility had been committed into the PJM capacity market as a capacity performance resource, eligible replacement capacity had to be located in that market, and behind the meter QF solar generation would not have qualified as eligible replacement capacity for a capacity performance resource. He noted that the potential capacity value that can be derived from solar QFs is not from their generation of power but from their load reducing effect, because as they reduce the peak load over time, they reduce the amount of capacity Dominion Energy North Carolina must procure through PJM. But, as shown in this case, where this generation exceeds the load requirements, there is no load reducing effect, and no impact on PJM capacity market procurement. (T. Vol. 6 at 81-83)

Witness Gaskill also clarified in response to questioning by the Attorney General's office that, as an alternative to putting power to Dominion Energy North Carolina as a QF, a developer could become a PJM market participant and sell its output into PJM. (T. Vol. 6 at 67-68)

Witness Petrie agreed in response to questions by counsel for SACE and the Public Staff that Dominion Energy North Carolina engages in generation and transmission planning on a system wide basis, including North Carolina and Virginia. (T. Vol. 6 at 59, 73)

Witness Gaskill confirmed that in response to a Public Staff discovery request he reconstructed Figure 1 from Dominion Energy North Carolina's Initial Filing, which had shown the tremendous recent growth in QF solar development in its North Carolina service area since 2013, to show the current level of QF solar development on the North Carolina portion of Dominion Energy North Carolina's system compared to its system average on-peak load. (T. Vol. 6 at 74-75)

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, we conclude that Dominion Energy North Carolina's proposal to set capacity rates at zero for the duration of the standard offer contracts approved in this proceeding is reasonable and appropriate and should be approved. As we have already made clear, with each biennial avoided cost case, we must re-evaluate our current policies with regard to the parameters of the standard avoided cost offer and the calculation of related avoided cost rates, taking into account the circumstances at the time. We agree with witnesses for Dominion Energy North Carolina and the Public Staff that the circumstances at this time are such that the traditional application of the peaker method is resulting in overpayment in excess of actual avoided costs and is not sending proper price signals to the market. We find that convincing evidence has been shown in this case that additional solar QF generation in its North Carolina territory will not allow Dominion Energy North Carolina to defer or avoid capacity needs. Given these circumstances, we determine that it is appropriate that we reach a different conclusion in this case with respect to the issue of QF capacity payments than we have in previous orders. To do otherwise would be to force customers to make payments to QFs in excess of avoided costs, and would ignore the evidence Dominion Energy North Carolina has presented demonstrating that, when we are determining avoided capacity costs, location matters.

First, it is clear based on its load forecasts that Dominion Energy North Carolina does not have a near-term need for capacity, and in this respect among many others its position differs from that of 2014. Just as important, however, we are persuaded that, even if its long-term planning indicated a need for capacity, additional distributed solar generation in North Carolina will not permit Dominion Energy North Carolina to defer or avoid capacity needs on its system. We find persuasive testimony showing that, before the influx of solar capacity that Dominion Energy North Carolina has experienced in recent years, QFs interconnecting at the distribution level on its system acted as load reducers, which reduced the load forecast, and therefore potentially deferred the need for new capacity. Due to the current saturation of its North Carolina system with distributed solar generation, this load-reducing effect is no longer occurring. In fact, Dominion Energy North Carolina has shown that QF development in its North Carolina service area has reached the point where the amount of distributed solar on its system exceeds its average on-peak load for this area.

Specifically, as of the hearing in this proceeding, Dominion Energy North Carolina had 521 MW of North Carolina solar capacity under contract, as compared to 518 MW of average on-peak load in North Carolina. When we consider solar QFs with LEOs, the total of potential solar capacity in Dominion Energy North Carolina's North Carolina territory rises to 680 MW. When we account for solar QFs with CPCNs, that total rises to 1,500 MW. Finally, when we recognize both North Carolina and PJM queued projects, the total increases to *2,800 MW*.

The evidence also shows that this development is occurring on a geographically and electrically narrow segment of Dominion Energy North Carolina's North Carolina territory, with approximately 80% of the interconnected distributed solar generation on its North Carolina system located on only 15 substations out of 42. Dominion Energy North Carolina's February 1, 2017 interconnection queue report (NCSEA-DNCP Cross Exhibit 1) shows that when the capacity associated with projects that have either connected or executed an interconnection agreement are totaled according to their respective substations, 79% of those projects are located on 15[16] of Dominion Energy North Carolina's North Carolina substations, consistent with witness Gaskill's testimony. Taken together, this evidence clearly shows that additional solar QF generation in its North Carolina territory will not reduce Dominion Energy North Carolina's load requirements or allow it to defer or avoid capacity need. We conclude that customers should not be forced to continue to pay for capacity that is not needed, and agree that to force such payments when new QF generation will not allow capacity needs to be avoided would violate the concept of avoided costs under PURPA as well as the requirement that customers be indifferent as to QF purchases.

We note that this reduction of the standard offer capacity rate to zero does not necessarily mean that large QFs cannot obtain capacity payments. As Dominion Energy North Carolina has explained, with more QFs receiving non-standard contract rates and terms, it can ascertain whether based on its location and characteristics a project may in fact allow it to avoid or defer capacity, and reflect that avoidance in the rates. We agree with Dominion Energy North Carolina however, that, on average and for standard QFs, it is appropriate to not include a capacity rate in the standard offer at this time.

We find unavailing implications that Dominion Energy North Carolina can simply sell excess capacity offered by additional distributed solar QFs into PJM. Relying on this contention would place an unreasonable and discriminatory burden on Dominion Energy North Carolina since, as witness Petrie has explained, PJM's new capacity market rules

[16] Those 15 substations are: Hornertown (77.5 MW), Murphy (59.5 MW), Everetts (49.9 MW), Sligo (24.9 MW), Whitakers (23.3 MW), Aydlett (20 MW), Northampton (20 MW), Scotland Neck (20 MW), Tunis (20 MW), Parmele (18.4 MW), Battleboro (15 MW), Earleys (15 MW), Winfall (15 MW), Woodland (15 MW), and Creswell (14 MW).

present significant risk to solar resources bidding into that market. More fundamentally, however, based on testimony offered by witness Gaskill at the hearing, which distinguished a solar QF selling to Dominion Energy North Carolina under PURPA from a solar developer that becomes a PJM market participant and gains the ability for its output to be sold at wholesale into PJM, this does not appear to be a feasible outcome. Finally, we note that our decision on this point is supported by FERC's discussion in *Order No. 69* of the utility purchase obligation provided at Section 292.303(a) of its rules:

> [a] qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.[17]

We recognize, as indicated by the Public Staff's data request and cross exhibit, that this distributed solar capacity does not exceed Dominion Energy North Carolina's total system load. We also acknowledge the parties' agreement that generation and transmission planning occur on a system-wide basis. However, for purposes of avoided cost determinations we agree with Dominion Energy North Carolina that location is the key consideration, and determine that the lack of capacity need avoidance that will result from additional intermittent generation in northeastern North Carolina, and the resulting potential for customer overpayments to QFs, supports our conclusion.

We also conclude that Dominion Energy North Carolina's proposal is consistent with FERC's regulations that provide for the consideration of capacity availability in determining avoided cost rates. Section 292.304(e) of those rules provides that "In

[17] *Order No. 69*, 45 Fed. Reg. at 12,219.

determining avoided costs, the following factors shall, to the extent practicable, be taken into account," and lists, among other things (including the data provided by utilities pursuant to 292.302(b)), "the availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods." This rule then lists the following indicators of that availability:

> (i) The ability of the utility to dispatch the qualifying facility; (ii) The expected or demonstrated reliability of the qualifying facility; (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance; (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities; (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation; (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.[18]

Many of these factors relate to the availability of a QF facility and its ability to be dispatched and useful during times of utility need. As such, we find it appropriate that these factors be considered when determining avoided cost rates in these biennial proceedings. We also find that these factors support Dominion Energy North Carolina's capacity proposal. We note that among the other factors this rule states should be considered is "[t]he relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use."[19] We believe that this factor clearly supports Dominion Energy North Carolina paying a rate of zero for capacity where a QF does not permit the avoidance of capacity need.

[18] 18 C.F.R. § 292.304(e)(2) (2016).
[19] 18 C.F.R. § 292.304(e)(3) (2016).

Our conclusion on this matter is also consistent with FERC's recent *Windham Solar* decision, which stated that "the Commission's regulations allow state regulatory authorities to consider a number of factors in establishing an avoided cost rate. These factors which include, among others, the availability of capacity, the QF's dispatchability, the QF's reliability, and the value of the QF's energy and capacity, allow state regulatory authorities to establish lower avoided cost rates for purchases from intermittent QFs than for purchases from firm QFs." (*Windham Solar* at P 6 (citing 18 C.F.R. § 292.304(e)-(f) (2016)).

With regard to FERC's decisions in *Ketchikan* and *Hydrodynamics*, we conclude upon reevaluation of these decisions and the record in this proceeding that the rationale and decision in *Ketchikan* is relevant to this case, and that Dominion Energy North Carolina's proposal is consistent with these precedents. In *Ketchikan*, FERC stated that it has

> made clear that an avoided cost rate need not include capacity costs (as distinct from energy costs) where a QF does not 'permit the purchasing utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility' … Accordingly, an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity … while utilities may have an obligation under PURPA to purchase from a QF, *that obligation does not require a utility to pay for capacity that it does not need*.[20]

In its subsequent *Hydrodynamics* decision, FERC stated that "avoided cost rates need not include the cost for capacity in the event that the utility's demand (or need) for capacity is zero. That is, when the demand for capacity is zero, the cost for capacity may also be zero."[21]

[20] *City of Ketchikan*, 94 FERC ¶ 61,293, at 62,062 (2001) ("*Ketchikan*") (citing *Order No. 69*) (emphasis added) (citations omitted).
[21] *Hydrodynamics, Inc.*, 146 FERC ¶ 61,193 at P 35 (2014) ("*Hydrodynamics*") (discussing *Ketchikan*).

We agree with witness Petrie and witness Bowman that FERC's rationale in *Ketchikan* is applicable to this proceeding, and that consistent with this precedent the Utilities should not be forced to pay for capacity when they do not have a capacity need and new QFs cannot allow them to defer or avoid capacity needs. We also agree that our previous interpretation of *Hydrodynamics* warrants reconsideration, and conclude that unlike that case, the Utilities' proposals in this proceeding do not involve an arbitrary cap, or any cap at all, on installed QF capacity in their respective service areas. We stated in the Phase 1 Order that, based on the facts in *Hydrodynamics*, FERC determined that if a utility needs capacity over its planning horizon, "i.e., it can avoid building or buying future capacity by virtue of purchasing from a QF, the avoided cost rates must include the full cost of the future capacity that would be avoided." (Phase 1 Order at 35) Here, the evidence shows that Dominion Energy North Carolina does not have a near-term need for capacity, and that even over the long-term planning horizon, it cannot avoid building or buying future capacity by purchasing from a new QF located in North Carolina. Therefore we find Dominion Energy North Carolina's zero capacity proposal to be consistent with these precedents.

We also conclude that our approval of Dominion Energy North Carolina's proposal is consistent with this Commission's previous decisions permitting Dominion Energy North Carolina to not include a capacity credit when it did not have a capacity need.[22] We agree with witness Petrie's testimony that the fact that Dominion Energy

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[22] *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 1998*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 81 (July 16, 1999); *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 1996*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 79 (June 19, 1997); *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying*

North Carolina used the DRR method to determine avoided costs at the time of these decisions does not affect the appropriateness of excluding capacity payments from avoided cost rates. The deciding factor is whether the utility has a need for capacity that the QF allows the utility to avoid. While in recent avoided cost proceedings we have concluded that Dominion Energy North Carolina in fact could avoid capacity additions through purchases from additional QF generation in North Carolina, based on the evidence presented in this case we conclude that it currently has no such need.

For similar reasons, we conclude that Dominion Energy North Carolina's proposal is consistent with the modified application of the peaker method we are approving in this proceeding. As noted by intervenor testimony, the traditional peaker method's calculation of avoided generation capacity cost does not depend on the utility's capacity expansion plan or require that the QF have operating properties that align with the utility's planned capacity addition. However, given the volume of evidence that incremental solar generation in its North Carolina service area will not permit Dominion Energy North Carolina to defer or avoid capacity needs, and the clear statements from FERC's rules and precedent that QF capacity value should be considered when determining rates, we find it appropriate that we approve Dominion Energy North Carolina's proposed modification to the traditional peaker method of not providing capacity payments for the duration of the standard offer contract. We acknowledge that this is a change from our determination in the Phase 1 Order, where we noted among other factors Dominion testimony suggesting that a utility's sufficient near-term capacity does not impact the cost of future needed capacity. (Phase 1 Order at 35) In this case,

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Facilities – 1994, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 74 (June 23, 1995).

Dominion has not only clearly shown that it does not have a near-term need for capacity, but has also demonstrated that for numerous reasons incremental North Carolina distributed solar generation will not allow it to defer or avoid capacity needs. In these circumstances any relation between Dominion's lack of near-term capacity need and the long-term costs for future capacity needs is not relevant. What is relevant is that, without this change, Dominion Energy North Carolina's customers will overpay for QF output, because they will be paying for capacity value they are not receiving, a result that would violate the fundamental tenets of PURPA that avoided cost rates be just and reasonable to utility customers and permit customers to remain indifferent as between QF purchases and other procurement options.

Therefore, due to the lack of need for incremental capacity in Dominion Energy North Carolina's North Carolina service area, and the inability of incremental solar generation in this area to reduce load or otherwise allow it to avoid building or buying capacity, we conclude that Dominion Energy North Carolina's proposal to make no capacity payments to QFs that sign a standard offer contract during this biennial period complies with PURPA and FERC requirements, is consistent with PURPA's indifference standard, and more appropriately strikes the balance we seek between encouraging QFs and protecting customers, and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding is found in the testimony of Duke witnesses Bowman and Snider, Dominion Energy North Carolina witness Petrie, Public Staff witnesses Metz and Hinton, SACE witness Vitolo, NCSEA witness Johnson, and the entire record in this proceeding.

In her direct testimony, Duke witness Bowman introduced Duke's proposal to modify the currently approved PAF of 1.20 to 1.05 for QFs eligible for the standard offer. (T. Vol. 2 at 358) In his direct testimony, Duke witness Snider explained that this change will align the PAF with the reliability of a CT, which is currently the basis for establishing the avoided capacity cost using the peaker methodology. (T. Vol. 2 at 223-226)

Public Staff witness Metz agreed that the 1.20 PAF may no longer be appropriate for use in calculating avoided cost rates. (T. Vol. 8 at 126) Both Public Staff witnesses Metz and Hinton recommended adjusting the PAF to 1.16 based on an average fleet-wide availability factor. (T. Vol. 8 at 36-39, 127-129)

SACE witness Vitolo contended that the current PAF of 1.20 better aligns with the availability of units in a utility fleet, and should be maintained. (T. Vol. 7 at 45)

NCSEA witness Johnson asserted that a PAF of 1.05 would not allow a solar generator to receive full payment of avoided capacity costs, because it is "incapable" of generating electricity during 95% of the on-peak hours, since many on-peak hours occur during non-daylight hours. (T. Vol. 7 at 301)

In his rebuttal testimony, Dominion Energy North Carolina witness Petrie explained that, consistent with its proposal not to make a capacity payment to QFs for the duration of the standard offer contract, Dominion Energy North Carolina did not propose any adjustments to the PAF. Witness Petrie agreed, however, that the PAF issue merits reevaluation in this proceeding, and testified that, to the extent that the Commission directs the Utilities to offer capacity rates to QFs in this proceeding, a PAF of 1.05 would be appropriate. He explained that, since the peaker method determines avoided capacity costs based on the installed cost of a peaking CT unit, the peak hours availability of a peaking CT should be the basis for the PAF. He explained further that, if a QF cannot operate at a level of availability similar to or better than a CT during peak periods, and does not provide the same level of reliability as a CT, the QF should not be entitled to rates based on the avoided cost of a full CT. Specifically, he explained that if a QF is assumed to defer the need for a CT with 95% availability during peak hours, the QF should not receive the same capacity payment if it is only available 83% (or less) of the time. Witness Petrie explained that witness Johnson's testimony demonstrates precisely this distinction in availability and reliability between a solar facility and a CT. He also explained in response to witness Vitolo's assertions that the year-round availability of all fleet units is not the correct metric to use for this purpose, because it includes maintenance and planned outages that are purposely scheduled to occur during non-peak conditions. The appropriate measure for the PAF, witness Petrie concluded, is the availability of a CT during summer and winter peak hours, resulting in a PAF of 1.05. For the same reasons, witness Petrie disagreed with the Public Staff witnesses' recommendation of a 1.16 PAF. (T. Vol. 5 at 266-268)

Witness Petrie recognized that the Commission declined to accept this proposal in the 2014 biennial proceeding. He noted, however, that in making that decision, the Commission stated that there had been widespread QF development under the existing framework without adverse impacts to utility ratepayers. Witness Petrie testified that, as Dominion Energy North Carolina has shown, this is no longer true, because circumstances have changed since 2014, and utility customers are being adversely impacted. (T. Vol. 5 at 267)

In his rebuttal, Duke witness Snider testified that, if the Commission determines that the PAF should be based on a system availability metric as suggested by the Public Staff, then it should be based on a metric that represents the reliability of the system during peak demand periods, for which he suggested using the Equivalent Forced Outage Rate or EFOR. He explained that because EFOR represents the reliability of a unit or generating fleet during periods between planned maintenance intervals, it better indicates the reliability of a unit or fleet during peak demand periods when performance is critical. He concluded that while the precise method and basis for calculating a PAF can be debated, both the reliability of a CT and the reliability of the entire generating fleet support a PAF of no more than 1.05. (T. Vol. 2 at 281-284)

DISCUSSION AND CONCLUSIONS

Based on the record in this proceeding, and to the extent that any of the Utilities are required to pay capacity rates to QFs with LEOs established in this biennial period, the Commission concludes that it is appropriate at this time to reduce the PAF for all standard QFs to 1.05 as a better representation of the Utilities' actual avoided costs based on the availability of a CT peaking unit. We recognize that this determination represents a change from previous Commission precedent, but believe that consistent with our goal of continuing to evaluate the balance between the need to encourage QF development, on the one hand, and the risks to customers of overpayments, on the other, the change is justified based on the evidence presented in this case.

First, we agree with Dominion Energy North Carolina witness Petrie that, since the peaker method determines avoided capacity costs based on the installed cost of a peaking CT unit, the peak hours availability of a peaking CT should be the basis for the

PAF. It is reasonable that, if a QF cannot operate at a level of availability similar to or better than a CT during peak periods, and does not provide the same level of reliability as a CT, the QF should not be entitled to rates based on the full avoided cost of a CT. This is consistent with the overall theory of the peaker method, because while that theory posits that the cost of a hypothetical CT, together with the marginal system running cost, should equal the cost of any generating plant, including a baseload plant, the PAF is an adder specific to the avoided capacity payment, which is based on the cost of a CT. We also agree with witness Petrie that the distinction in availability and reliability between a solar facility and a CT raised by witness Johnson further supports basing the PAF on the availability of a peaking CT.

We also find persuasive Duke witness Snider's testimony that, even if system availability is used as the basis for the PAF, a PAF of 1.05 remains appropriate. We agree that a metric, such as the EFOR, that represents the reliability of a unit or generating fleet during periods between planned maintenance intervals and shows the reliability of a unit or fleet during peak demand periods when performance is critical, is also reasonable as a basis for the PAF. Further, as witness Petrie explained, we conclude that year-round availability of all fleet units is not the correct metric to use for this purpose, because it includes maintenance and planned outages that are purposely scheduled to occur during non-peak conditions, and that the appropriate measure for the PAF is the availability of a CT during summer and winter peak hours.

Even more compelling, as emphasized by the Utilities' witnesses, given that utility customers are now experiencing adverse cost impacts under the current framework, the rationale we applied in the Phase 1 Order that widespread QF development was occurring with no adverse impacts to ratepayers no longer holds true. In that Order, we concluded in maintaining the 1.20 PAF, that there had been "widespread QF development under the existing framework without adverse impacts to utility ratepayers." (Phase 1 Order at 56) As a rate multiplier that gives an allowance for some amount of unit unavailability, the 1.20 PAF has resulted in more capacity revenue to QFs, and consequently helped encourage QF development. However, given the adverse impacts that are now being experienced by customers from above-market payments and payments in excess of avoided costs that have been demonstrated in this proceeding, the 1.20 PAF is no longer justified.

Therefore, based on the entirety of the record in this proceeding, it is reasonable and appropriate that, to the extent a utility is required during this biennial period to provide capacity credits in the avoided cost rates it offers to QFs, a PAF of 1.05 should be used to determine those capacity credits.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding is found in the testimony of Duke witnesses Bowman and Freeman, Dominion Energy North Carolina witness Gaskill, and Public Staff witnesses Lucas and Hinton.

In their direct testimonies, Duke witnesses Bowman and Freeman recommended improvements to the process by which QFs establish an LEO. Witness Bowman testified that the current standard to establish an LEO, as approved in the 2014 biennial proceeding, requires the QF developer to take the following actions: (1) self-certify with FERC as a QF; (2) obtain a CPCN from the Commission to construct the generator; and (3) indicate its intent to make a commitment to sell the facility's output under PURPA via the use of an approved Notice of Commitment Form. Witness Bowman also testified that the current process is increasingly imposing unjust and unreasonable purchase obligations on Duke's customers without actually obligating the QF to sell to the utility. (T. Vol. 2 at 361-362) Witness Freeman, who manages both power contracting and distribution interconnection activities for DEC and DEP, also testified to his recent experience that the commitment to sell purportedly being made by QFs who submit the Notice of Commitment Form is not meaningful or binding on the QF. (T. Vol. 2 at 436-437) Witness Freeman recommended that the Commission transition the current LEO standard to formalized contracting procedures between larger QFs and the utilities to more appropriately align the establishment of an LEO with the date upon which a QF actually agrees in a PPA to commit itself and becomes obligated to deliver power over a specified term. (T. Vol. 2 at 450-454) Witness Freeman also supported a streamlined LEO form for small QFs 1 MW or less that are eligible for the standardized avoided cost rates and terms and conditions, which would consist of (1) submission of a Report of Proposed Construction to the Commission under Rule R8-65; (2) submission of a Section 2 or Section 3 Interconnection Request, which the utility deems complete; and (3) indication of intent (i.e., a notice of commitment) to sell the QF's output to Duke under then-approved standard avoided cost rates. (T. Vol. 2 at 452-453)

Public Staff witness Lucas testified that the Public Staff agreed with witness Freeman's LEO standard proposal for small QFs 1 MW or less that are eligible for the utilities' standard offer. (T. Vol. 8 at 95). However, for larger QFs not eligible for the standard offer, the Public Staff did not agree with Duke's modified proposal to tie the establishment of a LEO to execution of the PPA. Instead, the Public Staff recommended the Commission apply the same LEO standard as for standard QFs, but with two additional requirements: (1) the QF must be a Project A or Project B in the interconnection queue, as described in Section 1.8 of the NCIP; and (2) the LEO would not be established until the earlier of the QF's receipt of the utility's System Impact Study or 105 days after the QF submits a complete interconnection request to the utility. Witness Lucas explained that projects designated as Project C status or below should be ineligible to establish an LEO because only projects designated as A or B are evaluated in the interconnection study process, and until the project begins progressing through the study process, the project owner has little or no information regarding whether it is technically or economically feasible to interconnect at its requested point of interconnection. Witness Lucas also explained that under the timeframes in the NCIP, a utility should complete the System Impact Study for a Project A or Project B within 105 days of interconnection request submission, assuming all timeframes in the NCIP are followed. Upon receiving the System Impact Study results, a QF owner should have information on the feasibility, costs, and time required for its proposed interconnection, and therefore be in a better position to evaluate the viability of the project and commit to building the facility than at the beginning of the interconnection process. (T. Vol. 8 at 96-99). Witness Lucas stated that he believed the Public Staff's proposal was more consistent with recent FERC precedent.[23] (T. Vol. 8 at 99).

Witness Lucas also testified that the Public Staff agrees with Duke's concerns about the current Notice of Commitment Form resulting in "stale" rates that are no longer representative of the utility's current avoided costs at the time the QF begins delivering power, and suggested that other proposed PURPA policy changes recommended by

[23] *FLS Energy, Inc.*, 157 FERC ¶ 61,211 (2016).

Public Staff witnesses Hinton and Metz would help address part of this concern. However, witness Lucas also testified that in the event avoided cost rates begin to increase, a QF may instead wish to delay its establishment of a LEO, or even allow a previously executed Notice of Commitment to expire in order to establish a new LEO at the higher rates. In this case, a change in the LEO date could result in customers losing the benefit of the lower rates to which the QF had previously committed, and even potentially allow gaming of rates by a QF at customers' expense. The Public Staff proposed that the LEO form be modified to include a provision that limits a QF that withdraws its Notice of Commitment from being able to establish a new LEO for two years from the date of the withdrawal, and instead limit the QF to the utility's "as available" energy rates during that time. (T. Vol. 8 at 101-102).

Public Staff witness Hinton testified that the Public Staff generally agrees with witness Freeman's testimony regarding the establishment of reasonable contracting procedures that improve the transparency and efficiency of the negotiated PPA process. Witness Hinton recommended Duke provide additional details regarding its proposal, and specifically highlighted his support for certain standards including providing for specific timeframes for both parties to provide information and responses; providing for a standardized contract form with clear delineation of any specific changes or points of negotiation clearly identified; providing for the utility to deliver indicative pricing for a sufficient period of time to allow the QF to evaluate the viability of its project and be able to seek financing; and providing an opportunity for either party to seek informal resolution of disputes or to petition for arbitration with the Commission. (T. Vol. 8 at 62-63)

Witness Freeman's rebuttal testimony presented a revised Notice of Commitment Form for small QFs 1 MW or less that are eligible for the Utilities' standard offers (DEC/DEP Freeman Rebuttal Exhibit 1). (T. Vol. 2 at 468). He stated that the modified standard offer Notice of Commitment Form was consistent with the proposal presented in his direct testimony as supported by Public Staff witness Lucas. (T. Vol. 2 at 469). Witness Freeman's rebuttal testimony also presented a "Notice of Intent to Negotiate a PPA" form in DEC/DEP Freeman Rebuttal Exhibit 2. Section four of this form presented contracting procedures for large QFs negotiating a PPA. Witness Freeman testified that the proposed contracting procedures are commercially reasonable and will improve the transparency and efficiency of the negotiated PPA process by establishing clear milestones and a process for good faith negotiations between the QF and utility. He also explained that the contracting procedures modify the process for a large QF to make a legally enforceable commitment to sell by focusing on the QF's commitment to enter into a PPA as establishing its obligation to deliver energy or capacity over a specified term. Under the contracting procedures, the decision to make such a commitment is completely within the QF's control, and only where the QF and the utility cannot agree on the terms and conditions of the PPA would the Commission need to get involved to determine whether a non-contractual LEO has been established. Prior to the QF making a commitment to sell by entering into a PPA, the utility will provide non-binding indicative avoided cost pricing that may be used by the QF developer to make determinations regarding project planning, financing, and feasibility of the proposed QF project. This approach mitigates the risk of stale avoided cost rates as the QF will be provided indicative pricing information needed to evaluate developing the QF, but will not "lock in" avoided cost rates until it actually makes a commitment to deliver power to the utility over a specified term by executing a PPA. (T. Vol. 2 at 470-471).

Witness Freeman requested the Commission direct Duke to take input from the Public Staff, Dominion Energy North Carolina, and other interested parties on the large QF Notice of Intent to Negotiate Form and contracting procedures presented in Freeman Rebuttal Exhibit 2 and to submit any refinements to the proposed contracting procedures as a post-hearing filing. (T. Vol. 2 at 469)

In his rebuttal testimony, Dominion Energy North Carolina witness Gaskill described the current requirements for a QF to establish an LEO under the 2014 biennial proceeding orders: receive a CPCN or Report of Proposed Construction; be a QF; and submit a "Notice of Commitment" form, which Dominion Energy North Carolina calls the LEO Form. Witness Gaskill testified that, while Dominion Energy North Carolina did not specifically recommend changes to the LEO Form in its Initial Filing and direct testimony, he shares many of the same concerns raised by the Duke witnesses in their testimony. He explained that the current LEO process, while improved in the 2014 biennial proceeding with the determination of a uniform LEO Form and the addition of the QF status requirement, still allows a QF to establish an LEO before it is in a position to truly commit to develop the project and deliver power in a timely manner. He also explained that, in practice, the LEO Form has been used by North Carolina QFs as a means to establish a put option price, but it has not obligated the QF to actually deliver power to the utility. (T. Vol. 5 at 200)

Witness Gaskill testified that this situation presents two significant implications, both of which unjustly harm customers. First, it impairs adequate utility system planning, because Dominion Energy North Carolina does not know how much QF power will ultimately be constructed and delivered, since it cannot rely on the QF energy and capacity to be available based on an LEO. As a result, Dominion Energy North Carolina must, in order to meet its obligation to meet customer requirements, secure short- and long-term capacity without accounting for QFs, thus reducing or eliminating any avoided capacity costs. Second, he explained that the current process has created a situation where the LEO, and thus the avoided cost prices, are significantly outdated by the time the QF actually completes construction and begins delivering output. The result is that customers are paying rates to QFs that established LEOs and therefore qualified for avoided cost rates that in many cases were calculated years prior to the QF actually coming online. (T. Vol. 5 at 201)

Witness Gaskill argued that Duke's proposed LEO process would better align a QF's commitment to the point in time at which it can be reasonably sure whether it will proceed with the project. He agreed that Duke's proposal for small QFs 1 MW or less is a reasonable step to ensure that the QF is in fact progressing in its development. He also agreed that either of Duke's initial proposals for large QFs—establishing the LEO after execution and return of a Facilities Study Agreement, or tying the LEO to the negotiated PPA process—would be an improvement over the current process, because they also better align the LEO with the point in time at which the QF has enough information to actually commit to development. Witness Gaskill testified that witness Lucas' recommendations for the large QF standard would still allow QFs to establish an LEO before they have made any material financial commitments beyond the interconnection fee or actual commitment to delivery output to the utility, but stated that he did not object to these recommendations as they are an improvement over the current process, assuming that the requirement to obtain a CPCN or RPC would remain in place. (T. Vol. 5 at 202-203)

Finally, witness Gaskill testified that although Dominion Energy North Carolina did not submit a modified LEO Form, he believes that the LEO requirements should be uniform for all QFs in the State, regardless of the utility to which the QF interconnects. He stated that, once the Commission determines any changes to the requirements for an LEO in this proceeding, Dominion Energy North Carolina would work with the Public Staff, Duke, and other stakeholders on the appropriate modifications to the LEO Form to implement those requirements. (T. Vol. 5 at 203)

At the hearing, in response to questions by counsel for Duke, witness Gaskill agreed that that the current process for establishing an LEO is not a meaningful determination of when a QF is ready, willing, and able to commit to sell. He also testified that tying the LEO to the contracting process would be an improvement to the process, as it would clarify expectations and requirements for both the QF and the utility. He stated that Dominion Energy North Carolina would be willing to work with other parties to reach agreement on that process. (T. Vol. 6 at 78)

DISCUSSION AND CONCLUSIONS

The Commission concludes that Duke's proposed contracting procedures should be approved subject to an opportunity for input on the Notice of Intent to Negotiate Form by the Public Staff, Dominion Energy North Carolina, and other interested parties. After considering such input, Duke and Dominion Energy North Carolina shall either jointly or individually file with the Commission a proposed final Notice of Intent to Negotiate

Form and contracting procedures within 30 days of this Order. Other parties may file responsive comments within seven days thereafter.

The Commission also approves Duke's modified Notice of Commitment Form for small QFs under 1 MW that are eligible for the Utilities' respective standard offer contracts. The Commission finds that the proposed streamlined standard offer LEO form presented in DEC/DEP Freeman Rebuttal Exhibit 1 should be modified to incorporate the Public Staff's recommendation related to a QF potentially withdrawing its LEO, as discussed above. Duke and Dominion Energy North Carolina shall either jointly or individually file with the Commission a proposed modified Notice of Commitment Form within 30 days of this Order.

Upon final Commission approval of the streamlined LEO form and the Notice of Intent to Negotiate Form, the Utilities shall place the forms on their websites, as well as post on those websites information regarding how both small QFs eligible for the Utilities' respective standard offers as well as large QFs may establish LEOs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

This finding is essentially uncontroverted. In his direct testimony, Dominion Energy North Carolina witness Gaskill described two minor modifications that Dominion Energy North Carolina has proposed for its standard avoided cost contracts that it intends will simplify and clarify certain terms of those contracts. First, he noted that Dominion Energy North Carolina has removed the map requirement from Exhibit D of the standard contracts, since this information is already incorporated into each QF's CPCN application and is therefore duplicative. Second, Dominion Energy North Carolina proposed to insert a provision to Article I of the Schedule 19-FP standard contract for the QF to choose the

Option A or Option B rate schedule. Since the previous contract did not provide for this clear election, this change would clarify precisely which option the QF selects. (T. Vol. 5 at 163) No party offered any testimony in response to these proposed modifications. We find these modifications to be reasonable and conclude that they should be approved.

The Commission therefore concludes that the rate schedules and standard contract terms and conditions proposed in this proceeding by Dominion Energy North Carolina should be approved, except as otherwise discussed herein. Dominion Energy North Carolina should be required to file new versions of its rate schedules and standard contracts, in compliance with this Order, within twenty (20) days after the date of this Order. Those should be allowed to go into effect fifteen (15) days after they have been filed. Dominion Energy North Carolina's filing should stand unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

IT IS, THEREFORE, ORDERED as follows:

1. That Dominion Energy North Carolina shall offer long-term levelized rates and contract terms for 5-year and 10-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 1 MW or less capacity, and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 1 MW or less capacity. The standard levelized rate option of 10 years shall include a condition making contracts under that option renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties

negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors, or (2) set by arbitration. Dominion Energy North Carolina shall offer its standard 5-year levelized rate option to all other QFs contracting to sell 1 MW or less capacity.

2. That Dominion Energy North Carolina shall continue to offer, as an alternative to avoided cost rates derived using the peaker methodology, avoided cost rates based upon market clearing prices derived from the markets operated by PJM, subject to the same conditions as approved in the Commission's Sub 106 Order. Dominion Energy North Carolina shall revise Schedule 19-LMP to provide that the energy price that it will pay pursuant to that rate schedule is the LMP at the PJM-defined nodal location nearest to where the energy is delivered.

3. That Dominion Energy North Carolina shall offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation: (a) participating in the utility's competitive bidding process; (b) negotiating a contract and rates with the utility; or (c) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a solicitation underway, any unresolved issues arising during such negotiations will be subject to arbitration by the Commission at the request of either the utility or the QF for the purpose of determining the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will conduct such an arbitration only if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates shall have the option of selling

into the wholesale market. The exact points at which an active solicitation is regarded as beginning and ending for these purposes shall be determined by motion to, and order of, the Commission. Unless there is such a Commission order, it will be assumed that there is no solicitation underway. If the variable energy rate option is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

4. That, to the extent that a utility is required pursuant to this Order to provide a capacity credit at any time during the term of standard offer contracts entered into under this proceeding, a PAF of 1.05 shall be utilized to calculate such avoided capacity rates for all QFs eligible for standard rates and terms.

5. That Duke's modified Notice of Commitment Form for small QFs under 1 MW that are eligible for the Utilities' respective standard offer contracts is approved. Duke and Dominion Energy North Carolina shall either jointly or individually file with the Commission a proposed modified Notice of Commitment Form within 30 days of this Order. Duke's proposed contracting procedures are also approved subject to an opportunity for input on the Notice of Intent to Negotiate Form by the Public Staff, Dominion Energy North Carolina, and other interested parties. After considering such input, Duke and Dominion Energy North Carolina shall either jointly or individually file with the Commission a proposed final Notice of Intent to Negotiate Form and contracting procedures within 30 days of this Order.

6. That the rate schedules and standard contract terms and conditions proposed in this proceeding by Dominion Energy North Carolina are approved, except as otherwise discussed herein. Dominion Energy North Carolina shall file new versions of

its rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order, to become effective 15 days after the filing date unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 15-day period.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of _____________, 2017.

NORTH CAROLINA UTILITIES COMMISSION

M. Lynn Jarvis, Chief Clerk

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Proposed Order of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina* filed in Docket No. E-100, Sub 148 was served electronically or via U.S. mail, first-class, postage prepaid, upon all parties of record.

This, the 22nd day of June, 2017.

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