BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 148

In the Matter of: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016	))))))	**POST-HEARING BRIEF OF SOUTHERN ALLIANCE FOR CLEAN ENERGY**

PURSUANT TO North Carolina Utilities Commission ("Commission") Rule R1-25, the Presiding Commissioner's ruling made in open hearing on April 21, 2017, the Commission's May 15, 2017 Notice of Due Date for Proposed Orders/Briefs, and June 9, 2017 Order Granting Motion for Extension of Time to File Proposed Orders, intervenor Southern Alliance for Clean Energy ("SACE"), through counsel, files this brief on certain issues in the current biennial proceeding, which concerns the 2016 avoided cost rates for Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, Inc. ("DEP") (together, "Duke Energy"), and Dominion North Carolina Power ("Dominion" or "DNCP") (collectively, "the Utilities").

I. INTRODUCTION

In this proceeding, the Utilities have proposed to drastically alter the Commission's policies governing avoided cost rates and contract terms. Their proposals would fundamentally change North Carolina's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the state's clean energy economy. Underpinning these proposals are claims by the Utilities that the recent increase of solar Qualifying Facilities ("QFs") on the grid have led to emergency conditions which require swift and decisive action by the Commission.

Despite the Utilities' allegation of rampant QF development and claim that this is a new concern for the Utilities, the proposed rollbacks are in large part identical to proposals that the Utilities have previously raised and the Commission has rejected in past avoided cost proceedings. The evidence in this proceeding has shown that despite these claims lamenting increased solar energy on the grid, the Utilities have failed to take necessary steps to plan for the integration of these solar resources. Instead, the Utilities now attempt to use PURPA implementation and curtailment as blunt instruments to address their perceived problem.

The Utilities' proposals, individually and in the aggregate, would discourage future QF investments in North Carolina. The proposals would give more power and control to the Utilities, while limiting QF options for financing and project development. The Utilities seek to force more QFs into the bilateral negotiation process, which would grant Utilities increased control over contract conditions, terms, and offered rates. The power imbalance in the negotiation process ultimately undercuts the viability of QF projects in the state and limits Commission oversight, at least until disputes arise. The Utilities claim these changes are necessary to alleviate their alleged concerns, but in reality the proposals are a thinly-veiled attempt to shift control over renewable energy development to the Utilities and reduce the number of QF projects in the state, in violation of the letter and spirit of PURPA, North Carolina law, and this Commission's established precedent.

II. PROCEDURAL BACKGROUND

In its June 22, 2016 Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing, the Commission announced that it was scheduling a public hearing for taking nonexpert public witness testimony and that the Commission would attempt to resolve all issues arising in the docket based on written statements, comments, exhibits and avoided cost schedules, rather than a full evidentiary hearing. Order Establishing Biennial Proceeding and Scheduling Hearing, Docket No. E-100, Sub 148 (June 22, 2016) at 1. On November 15, the Utilities filed their Initial Statements and Exhibits. In its December 30, 2016 Order Scheduling Evidentiary Hearing and Amending Procedural Schedule, the Commission amended the procedural schedule and calendared an evidentiary hearing in light of "the scope and complexity of the potentially contested issues in [the] proceeding." Order Scheduling Evidentiary Hearing and Amending Procedural Schedule, Docket No. E-100, Sub 148 (December 30, 2016) at 2. The new procedural schedule allowed time "for the parties to engage in discovery, prepare their filings, and to present their arguments at an evidentiary hearing." Id.

The Utilities and intervening parties filed testimony in advance of the evidentiary hearing in accordance with the Commission's December 30, 2016 Order and subsequent orders granting motions for extension of time, issued on March 23, 2017 and April 6, 2017. The evidentiary hearing was held April 18-21, 2017. The evidentiary hearing transcript was made available on May 15, 2017 and the post-hearing brief and proposed order deadline set for June 14, 2017. In response to a motion from Public Staff, the Commission extended the briefing and proposed order deadline to June 22, 2017.

III. LEGAL FRAMEWORK FOR IMPLEMENTING PURPA

Section 210 of PURPA requires large electric utilities to purchase available energy and capacity from small power producers, known as "qualifying facilities" or QFs. See generally 16 U.S.C. § 2601 et seq. The United States Supreme Court has declared that "Section 210 of PURPA was designed to encourage the development of cogeneration and small power production facilities." American Paper Inst. v. Am. Elec. Power Serv. Corp., 461 U.S. 402, 405 (1983). As the Court explained in FERC v. Mississippi, "Congress believed that increased use of these sources of energy would reduce the demand for traditional fossil fuels," and it recognized that electric utilities were traditionally "reluctant to purchase power from, and to sell power to, the nontraditional facilities." 456 U.S. 742, 750 (1982) (footnote omitted).

Under PURPA and the Federal Energy Regulatory Commission ("FERC") regulations implementing PURPA, the FERC has delegated to state commissions the responsibility to set rates for purchases from qualifying cogenerators and small power producers by electric utilities under their ratemaking authority. State ex rel. Utilities Comm'n v. North Carolina Power, 338 N.C. 412, 417, 450 S.E.2d 896, 899 (1994) (citing 16 U.S.C. § 824a-3(f)). See also Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of PURPA ("Order No. 69"), 45 Fed. Reg. 12214, 12215 (Feb. 25, 1980). In doing so, the FERC stated that it "believe[d] that providing an opportunity for experimentation by the States is more conducive to the development of these difficult rate principles." Id. at 12231. This Commission has elected to implement Section 210 of PURPA by holding biennial proceedings, such as the current proceeding.

PURPA requires that rates for the purchase of energy from QFs by electric utilities 1) shall be just and reasonable to the consumers of the electric utility and in the public interest, and 2) shall not discriminate against qualifying cogenerators or qualifying small power producers. 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304(a)(1). PURPA rates are set at the utility's avoided cost of producing the next incremental unit of electricity.

16 U.S.C. § 824a-3. The statute defines "incremental cost" as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." 16 U.S.C. § 824a-3(d). Similarly, FERC's PURPA implementing regulations reiterate that electric utilities are not required under PURPA to pay more for purchases than their avoided cost, 18 C.F.R. § 292.304(a)(2), defined 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.

18 C.F.R. § 292.101(b)(6).

The PURPA regulations require electric utilities to establish standard rates for purchases from QFs with capacity of 100 kilowatts ("kW") or less, and also give state commissions the authority to develop standard rates for larger QFs. 18 C.F.R. § 292.304(c)(1), (2). These standard rates "[m]ay differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies." Id. at (c)(3)(ii).

In addition to meeting the requirements of PURPA, this Commission also holds these biennial proceedings to determine utilities' avoided costs pursuant to North Carolina law. N.C. Gen. Stat. § 62-156(b) delegates to the Commission the responsibility to establish rates for small power producers, defined in N.C. Gen. Stat. § 62-3(27a) as a person or corporation owning or operating an electrical power production facility with a power production capacity which, together with any other facilities located at the same site, does not exceed 80 megawatts of electricity and which depends upon hydroelectric power for its primary source of energy.

PURPA leaves the specific methodology to be used in determining avoided cost to the states' discretion. See California Public Utilities Comm'n, Order Denying Rehearing, 134 FERC 61,044, 61,160 (2011) (granting state commissions the authority to decide what particular capacity is being avoided in setting avoided cost rates). In North Carolina, where the state legislature has not mandated the use of a particular avoided cost methodology, the appropriate methodology is left to this Commission, which has allowed the electric utilities to choose their method of setting avoided costs, subject to the Commission's review.[1] The Commission most recently directed the Utilities to use the peaker methodology to calculate their avoided cost rates. See Order Setting Avoided Cost Input Parameters, Docket No. E-100, Sub 140 (Dec. 31, 2014) ("E-100, Sub 140 Phase 1 Order") at 6.[2] The peaker method is designed to determine a utility's marginal capacity and marginal energy cost through generation production modeling. This approach estimates avoided capacity costs by using the capital costs of the lowest-cost capacity option available to the utility, typically a simple cycle combustion turbine ("CT"). Avoided energy costs are estimated using a cost simulation model to determine the marginal energy costs of running the utility's generation system with and without a block of QF power. See, e.g., Tr. Vol. VII, p. 166, ln 14-22; p. 167 ln 1-17; Tr. Vol. VIII, p. 25, ln 6-12; p. 26, ln 1-11.

[1] House Bill 589 currently pending before the North Carolina General Assembly has implications for many of the issues addressed in this proceeding. Because HB 589 is still pending legislative consideration at the filing of this brief, the brief does not address the legislation in any greater detail.
[2] Prior to the 2012 biennial avoided cost docket, DNCP used the Differential Revenue Requirement methodology to calculate its avoided cost rate).

IV. ARGUMENT

The Utilities have raised in this proceeding a long list of proposals that would reduce avoided cost rates and discourage QFs from entering into standard offer contracts or engaging in negotiations with the Utilities under PURPA.[3] To bolster their case for these rollbacks, the Utilities claim that the "surge of solar QFs" is unmanageable and that ratepayers are overpaying for QF power.[4] As admitted by witnesses on cross examination, however, the Utilities have engaged in studies of grid integration of QF power and they have tools at their disposal to better integrate QFs.[5] These studies and tools should be used, rather than attempting to stifle QF development through PURPA implementation changes, many of which the Commission has previously rejected. The Utilities' claim that ratepayers are overpaying for QF power is undermined by the admission that the overpayment estimates are based on the Utilities' own calculations and proposed avoided cost rates and changes, yet to be approved by the Commission.[6] These claims also fail to take into account PURPA's acknowledgment that over time, the potential for years of underpayment and years of overpayment for QF power should even out.[7] The Supreme Court has held that Section 210 of PURPA was designed to encourage the development of QF power.[8] The Utilities' proposals will do just the opposite.

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[3] See, for example, Public Staff John R. Hinton's testimony explaining the impact of the Utilities' various proposals on reducing the avoided cost rates. Tr. Vol. VIII, pp. 32-34; pp. 43-45.
[4] See, e.g., Tr. Vol. II, p. 225, ln 1-5; p. 320, ln 10-12; Tr. Vol. V, p. 135, ln 17-22; p. 136, ln 1-12; p. 212, ln 5-23; p. 213, ln 1-8.
[5] Tr. Vol. II, p. 146, ln 10-21; p.172, ln 7-24; p. 173, ln 1-3; Tr. Vol. III, pp. 125-129; Tr. Vol. VIII, pp. 237-242; see also Confidential SACE Duke Panel Cross-Examination Ex. 5.
[6] Tr. Vol. III, pp. 95-98. See also Tr. Vol. VII, pp. 199-205 (pointing to additional flaws in the Utilities' overpayment analysis).
[7] See Tr. Vol, VII, p. 101, ln 5-24; p. 102, ln 1-24; p. 103, ln 1-12; see also Tr. Vol. V, pp. 93-96 (questioning from Commissioner Brown-Bland to Duke Energy Witness Snider).
[8] American Paper Inst. v. Am. Elec. Power Serv. Corp., 461 U.S. 402, 405 (1983).

The Utilities' proposals to fundamentally alter the standard offer contract could grind QF development in North Carolina to a halt. The Commission should maintain the current standard offer contract eligibility threshold of 5 MW and contract duration of 15 years, which have been proven to encourage QF development. Although the Utilities emphasize opportunities for bilateral negotiation and a hypothetical competitive procurement process, the evidence has demonstrated that negotiations will fail to encourage QF growth, and the Utilities can provide only minimal information about any future competitive procurement process.

The Utilities also propose changes to avoided cost calculations that are directly contrary to the Commission's approved peaker method and which are not supported by the evidence in this proceeding. Specifically, the Commission should reject changes to the calculation of capacity payments, a reduction in the performance adjustment factor, a shift to a winter-peaking capacity valuation, and the elimination of line loss adjustments.

Finally, the Utilities have proposed changes to the legally enforceable obligation ("LEO") standard, and have asked the Commission to expand their ability to curtail QF power. The Commission should reject these proposals as contrary to PURPA and North Carolina law and should require the Utilities to more proactively and effectively plan for the integration of renewable energy resources on its grid.

A. Proposed Changes to Standard Offer Contracts

1. <u>The Utilities' proposal to reduce the standard offer contract eligibility threshold from 5 MW to 1 MW would discourage QF development in North Carolina, jeopardize financing, and undermine the goals of PURPA.</u>

In this proceeding, the Utilities have proposed reducing the standard offer contract eligibility threshold from 5 MW to 1 MW. Significantly, however, neither Duke Energy nor Dominion have demonstrated that a 1 MW standard offer eligibility threshold would encourage QF development. The Utilities have also failed to demonstrate that QFs 1 MW and below would have a reasonable opportunity to attract financing from potential investors under the Utilities' other proposed standard offer terms. A 1 MW eligibility threshold would also allow Duke Energy and Dominion to subject an increasing number of utility-scale solar QF developers in North Carolina to bilateral negotiations with the Utilities. The evidence in this proceeding demonstrates that, despite a greater number of contract negotiations in recent years, bilateral negotiations between QFs and the Utilities continue to be lengthy, resource-intensive, power-imbalanced endeavors. The Utilities have also indicated the negotiated contract terms will get worse for QFs, not better, in the future.

In describing the proposed 1 MW threshold, Duke Energy Witness Kendal C. Bowman distinguished between utility-scale projects and smaller QFs, stating that

> a 1 MW threshold is a reasonable proxy to differentiate between utility-scale developer sponsored solar and smaller QFs seeking to install renewable or alternative energy facilities for <u>primarily environmental or other non-commercial reasons</u>

Tr. Vol. II, p. 385, ln 6-9 (emphasis added). Duke Energy's characterization of smaller QFs suggests that, in fact, these smaller QFs may not be commercially viable under the proposed avoided cost terms. Indeed, testimony by SACE, North Carolina Sustainable Energy Association ("NCSEA"), and Cypress Creek Renewables witnesses demonstrated that 1 MW QFs would face diminished economies of scale and that smaller QFs would face greater difficulty obtaining project financing necessary to make these projects viable. Tr. Vol. VII, p. 27, ln 11-22; p. 378, ln 11-23; Tr. Vol. VI, p. 117, ln 3-10. Thus, one outcome of a reduced standard offer contract size threshold is that there will simply be fewer QFs selling output under the standard offer tariff because it is not economical to do so. Recognizing this possibility and other potential consequences, NCSEA Witness Dr. Ben Johnson advised against reducing the 5 MW threshold. Tr. Vol. VII, p. 329, ln 10-11. If the Commission does consider a threshold reduction, Witness Johnson recommended pursuing a more modest reduction such as 3.75 MW or 4 MW to minimize adverse impacts to QFs. Id. at ln 11-13. SACE Witness Dr. Thomas Vitolo recommended maintaining the 5 MW threshold. Tr. Vol. VII, p. 30, ln 5-7. Public Staff, SACE, and NCSEA witnesses all pointed out that for projects that fall above the threshold for a standard offer contract, bilateral negotiations remain "challenging, lengthy, and expensive." Tr. Vol. VIII, p. 56, ln 11-13; see also Tr. Vol. VII, p. 329, ln 2-4; Tr. Vol. VII, p. 26, ln 10-13; p. 380, ln 19-23; p. 381, ln 1-5.

The question of whether 1 MW projects could adequately secure financing for projects is greatly compounded by the Utilities' additional rollback proposals in this proceeding, including a reduction in the avoided energy rate, eliminating capacity credit in certain years, reducing the standard offer contract duration to 10 years, and adjusting avoided energy rates every two years. These factors—individually or collectively—putting downward pressure on avoided cost rates further decrease the economic potential for smaller projects at or under 1 MW.

If 1 MW QFs become commercially viable despite these significant issues, the standard offer decrease from 5 MW to 1 MW may overburden the Commission and Utilities by increasing the overall number of projects seeking to interconnect, as described by SACE Witness Vitolo. See Tr. Vol. VII, p. 28, ln 3-5. In other words, the Utilities may receive five interconnection requests for five separate 1 MW projects, rather than one interconnection request for a single 5 MW project under the current standard offer. As reiterated by NCSEA Witness Johnson, this five-fold increase in number of applications for the same MW amount of QF power could further delay or hamper interconnection queues that are already backlogged. Tr. Vol. VII, p. 329, ln 2-9. In rebuttal testimony, Duke Energy Witness Gary R. Freeman acknowledged the possibility that reducing the standard offer eligibility threshold to 1 MW would lead to a greater number of QFs and interconnection requests. Witness Freeman's proposed solution is that 1 MW QFs are "more likely to be eligible for and pass the NCIP Section 3 Fast Track screens." Tr. Vol. II, p. 472, ln 17-21. However, Public Staff Witness John R. Hinton testified that only 33% of QFs of 1 MW or smaller in DEP territory passed the Fast Track screens over the past two years. Tr. Vol. VIII, p. 59, ln 20-23. An increased number of applications for the same MW amount of QF power could further slow and clog the Utilities' interconnection queues, particularly when the Fast Track screens are only working for 33% of projects 1 MW and smaller in DEP territory.

The increased difficulty in financing 1 MW projects combined with potential for increased administrative burdens warrant maintaining the 5 MW eligibility threshold for standard offer contracts. It is uncontested in this proceeding that the 5 MW standard offer threshold has successfully encouraged the development of QFs in North Carolina. The 5 MW threshold should be maintained to minimize the adverse effects of reducing it, and to continue encouraging the development of QF power, as intended by PURPA.

2. <u>The Utilities' proposals to reduce the standard offer contract length from 15 to 10 years will deter QF growth, especially for smaller QFs.</u>

The existing 15-year standard offer contract length has proven to effectively encourage QF development in North Carolina, consistent with the policy goals of PURPA. In previous biennial avoided cost proceedings, the Commission has determined that a 15-year standard offer contract balances "the federal and North Carolina public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on customers." E-100, Sub 140 Phase 1 Order at 21. While the Utilities focus on the risk of customer overpayment – without adequately addressing potential underpayment – the evidence demonstrated that Duke Energy's unregulated renewables arm enters into solar PPAs for 15 years or longer; that 15-year levelized contracts provide QFs with an opportunity to attract financing; and that, while 10-year contracts may be viable for larger projects, they have not led to the development of smaller QFs—and certainly not QFs at or below 1 MW.

The FERC has consistently held that PURPA provides a QF the option to sell its output under a fixed long-term contract. As described by the Commission in past avoided cost proceedings, "a QF's legal right to long-term fixed rates under Section 210 of PURPA is well established as a result of the FERC's J.D. Wind Orders." E-100, Sub 140 Phase 1 Order at 19. Since J.D. Wind, the FERC has continued to apply this standard and has further clarified the requirements for QFs that opt to sell output under a LEO. Most recently, in November, 2016, the FERC held in Windham Solar that given the need for certainty with regard to return on investment, coupled with Congress' directive that the Commission encourage QF development, "a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors."[9]

In this proceeding, Duke Energy and Dominion have alleged, but not demonstrated, that a 10-year contract for QFs up to 1 MW will provide QFs reasonable opportunities to attract financing. Duke Energy has also alleged, but not demonstrated, that a 10-year contract with rates adjusted every two years for QFs up to 1 MW will provide QFs reasonable opportunities to attract financing. On cross-examination, Duke Energy Witness Lloyd M. Yates confirmed that Duke Energy Renewables, Duke Energy's unregulated renewable energy subsidiary, enters into long-term contracts with terms of 20 years. Tr. Vol. II, p. 48, ln 8-15. He stated that these facilities rely on long-term contracts in order to establish "long-term revenue streams." Tr. Vol. II, p. 44, ln 8-10. Witness Yates also indicated that Duke Energy Renewables borrows project development capital from the Duke holding company rather than from financial institutions and that Duke Energy Renewables does not provide project sponsor equity because that equity is provided at the holding company level. Tr. Vol. II, p. 40, ln 1-15. Witness Yates' testimony that Duke Energy Renewables' holding company serves as the lender for these projects suggests that Duke itself requires long-term contracts of 15 years or more. Duke Energy should allow QFs the same type of long-term contracts and long-term revenue streams that it requires for its own projects.

Additionally, the Utilities' claim that 15-year standard offer contracts are too long and uncertain ignores the reality of their own resource planning. The Utilities' own choice to build new power plants requires similar levels of uncertainty based on forecasts

[9] Windham Solar LLC & Allco Fin. Ltd., 157 FERC ¶ 61134 (Nov. 22, 2016)(hereinafter "Windham Solar").

of future prices. As the Commission stated in the previous avoided cost proceeding, and as Public Staff Witness Hinton testified in this proceeding, a utility's commitment to build a plant represents a similar type of long-term fixed obligation for the utility's customers, largely based upon forecasts of future prices. In many respects, the utilities own self-build options are based upon similar "uncertain" forecasts. E-100, Sub 140 Phase 1 Order at 20; Tr. Vol. VIII, p. 70, ln 7-10; p. 71, ln 1. Witness Hinton described resource decisions by Duke Energy—DEP's Richmond County Combined Cycle facility and DEC's Cliffside Unit 6—which turned out to be advantageous and disadvantageous for ratepayers, respectively, based on uncertain fuel prices at the time the resource decisions were made. Tr. Vol. VIII, p. 71, ln 3-11; p. 158, ln 1-16. While the Utilities warn of overpayment risks, they also overlook potential underpayment if avoided costs increase in the future. Tr. Vol, VII, p. 101, ln 5-24; p. 102, ln 1-24; p. 103, ln 1-12. These types of resource decisions are inherent in the Utilities' business model, yet the Utilities direct their criticism only to solar QFs.

The Utilities have failed to demonstrate that their proposal to limit standard offer contracts to 10 years would allow smaller QFs to obtain financing. On cross-examination regarding Duke Energy's 10-year negotiated contracts, Duke Energy Witness Bowman admitted that out of the 22 QF contracts negotiated between 2012 and 2017, the average nameplate capacity was over 37 MW, far higher than the current 5 MW standard offer threshold or the proposed 1 MW threshold. Tr. Vol.III, p. 85, ln 6-20; SACE Duke Panel Confidential Cross Ex. 1. Witness Bowman also noted that a number of the 22 contracts listed in the exhibit were labeled as "terminated" or "withdrawn." Tr. Vol. III, p. 84, ln 7-11. By removing the contracts in the exhibit marked "terminated" or "withdrawn," the average nameplate capacity increases to almost 40 MW.[10] None of the projects listed were under 1 MW in size. While Duke Energy has demonstrated that much larger QFs may be able to develop projects under 10-year contracts, it has not demonstrated that smaller QFs, especially QFs below and including 1 MW, would have a reasonable opportunity to obtain financing at 10-year terms.

As with the Utilities, the Public Staff did not evaluate whether smaller QFs could attract financing with 10-year terms. Public Staff agreed with making a shift to 10-year contracts in this proceeding based in part on its assessment that the Utilities have in recent years entered into negotiated contracts with QFs for 10 year terms, "indicating that it is possible to secure financing terms shorter than 15 years." Tr. Vol. VIII, p. 72, ln 10-12; p. 73, ln 1-3; p. 230, ln 7-19. However, Public Staff Witness Hinton acknowledged during cross-examination that in recommending a 10-year standard offer contract term, Public Staff did not consider the size of the specific QFs that had entered into 10-year contracts. Tr. Vol. VIII, p. 230, ln 23-24; p. 231, ln 1-4. As discussed above, the average nameplate capacity of QFs that have entered into these negotiated contracts is over 37 MW. Tr. Vol. III, p. 85, ln 6-11. Duke Energy has not shown that 5 MW projects, or 1 MW projects, would be able to obtain financing with 10-year terms.

On cross-examination, Witness Bowman further demonstrated that Duke Energy has not assessed whether QFs would have a reasonable opportunity to attract financing under Duke Energy's proposals. Tr. Vol. III, p. 86, ln 1-21. During discovery, Duke Energy was asked to provide copies of any and all reports, studies, or other documents that DEC or DEP had prepared internally or through external financial advisors,

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[10] There are eight "terminated" or "withdrawn" contracts listed out of the 22 contracts with 10 year terms. By removing these eight contracts, the total capacity becomes 554.4. The average [554.4 divided by 14] is 39.6 MW.

investment bankers, or any other third-party "with regard to the ability of a solar project to obtain financing in light of their proposal to offer only a ten-year contract with energy rates recalculated every two years." Duke Energy's response to all three requests was that the DEC and DEP "have no such reports." Id. at p. 87, ln 15-24; SACE Duke Panel Cross Ex. 2.

Although Witness Bowman stated that Duke Energy believes that its proposal is a "fair and adequate offering for standard contracts" and testified that it believes 1 MW projects would be able to obtain financing under 10-year terms, the evidence reveals that Duke Energy has not demonstrated that QFs would have a reasonable opportunity to attract financing under Duke Energy's proposed changes to the standard offer contracts. Tr. Vol. III, p. 86. The Commission should maintain the 15-year standard offer contract term which has been proven to allow QFs a reasonable opportunity to finance projects.

3. Duke Energy's proposal to update avoided energy rates every two years is inconsistent with PURPA.

In Duke Energy's Joint Initial Statement and Exhibits and in Direct Testimony, it revived a previously rejected proposal to update avoided energy rates in standard offer contracts every two years. DEP and DEC Joint Initial Statement and Exhibits, p. 29; Tr. Vol. II, p. 309, ln 14-19. In rebuttal testimony, Duke Energy maintained that the 2-year energy rate adjustment complies with PURPA, but also provided an alternative or "compromise" to the 2-year avoided cost rate updates proposed in the Initial Statement and Direct Testimony. Tr. Vol. II, p. 408, ln 1-13.

The Commission has previously considered and rejected a proposal by Dominion to vary avoided energy rates every two years. See Tr. Vol. VII, p. 39, ln 12-20 (citing the Commission's order in 2010 biennial avoided cost proceeding). At that time, the FERC had only recently issued its J.D. Wind Orders, clarifying that a LEO must provide QFs a fixed long-term contract with the rates established at the time the LEO is created. SACE Witness Vitolo pointed to Public Staff's explanation that, pursuant to the J.D. Wind Orders, "a rate that is reset every two years clearly does not qualify as either a fixed rate or as a fixed formula rate." Tr. Vo. VII, p. 40, ln 1-6 (citing Public Staff Proposed Order in Docket No. E-100, Sub 127 at 9 (April 29, 2011)). The Commission agreed with Public Staff's assessment and required the utility to begin offering fixed long-term levelized avoided energy rates for QFs in the following biennial proceeding.

Since 2010, the Commission has continued to apply the J.D. Wind Orders to maintain long-term fixed rates. In the E-100, Sub 140 Phase 1 Order, the Commission reiterated that

> [A] QF's legal right to long-term fixed rates under Section 210 of PURPA is well established as a result of the FERC's J.D. Wind Orders. The FERC has made clear that its intention in Order No. 69 was to enable a QF to establish a fixed contract price for its energy and capacity at the outset of its obligation because fixed prices were necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore its financial feasibility, before beginning the construction of a facility.

E-100, Sub 140 Phase 1 Order at 19-20. The FERC has emphasized that a QF that sells output under a LEO is entitled to a rate that is "determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred." Tr. Vol. VII, p. 36, ln 20-22; p. 37, ln 1-2 (citing J.D. Wind). The FERC's recent Windham Solar order further defines QF rights and utility responsibilities under PURPA.[11]

[11] In Windham Solar FERC held that "a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors."

Witnesses for NCSEA and Cypress Creek Renewables testified in this proceeding that avoided cost rates that are updated every two years would likely be viewed by investors as the equivalent of a 2-year contract and would not be financeable. Tr. Vol. VI, p. 120, ln 14-17; p. 7, ln 14-17. Public Staff also rejected Duke Energy's initial proposal, stating that "resetting energy rates every two years for facilities eligible for the standard offer rates adds an additional element of uncertainty to their ability to reasonably forecast their anticipated revenue, which may make obtaining financing difficult or impossible." Tr. Vol. VIII, p. 76, ln 1-4. Duke Energy admitted on cross-examination that it has not evaluated—either internally or through external sources—whether QFs will be able to attract financing with avoided energy rates updated every two years. Tr. Vol. III, p. 87, ln 15-24.

In rebuttal testimony, Duke Energy proposes an "alternative option." Under this alternative proposal, Duke Energy would still offer only 10-year contracts with energy rates updated every two years, but QFs would have the option of fixing the initial two-year energy rate for the duration of the 10-year contract. Tr. Vol. II, p. 371, ln 19-22; p. 372, ln 1-2. In rebuttal testimony, Duke Energy Witness Glen A. Snider conceded that this is an "imperfect" solution. Tr. Vol. II, p. 243, ln 20-23. At the hearing, Witness Snider stated that the 2-year rates offered to QFs under Duke Energy's alternative proposal are anticipated to be lower than the actual avoided cost rates during the remainder of the contract term. Tr. Vol. III, p. 31, ln 19-24. Duke Energy appears to present this alternative proposal as a "temporary" option, although Witness Snider indicated that Duke Energy would ask again for the two-year updates in the next biennial proceeding. Tr. Vol. II, p. 244, ln 3-5.

On its face, however, the amended proposal does not comply with PURPA. The two-year rates fixed for the 10-year proposed contract duration, as Duke Energy admits, would likely be below the avoided cost rates, contrary to PURPA's requirement that rates for purchase may not be set below the electric utility's avoided cost. 16 U.S.C. § 824a-3(b). For these reasons, the Commission should reject both Duke Energy's initial proposal and its revised proposal.

4. The Commission should not adopt various other states' PURPA implementation.

In direct and rebuttal testimony, Duke Energy cited to tariffs in other states that provide only one- or two-year contract terms.[12] Presumably, Duke Energy refers to these tariffs as an indication that the tariffs comply with PURPA and the FERC's regulations and orders implementing PURPA. As an initial matter, Duke Energy has not provided any evidence that FERC has assessed the validity of any of these tariffs under PURPA, particularly since the November 2016 Windham Solar order in which FERC further clarified that "given [the] need for certainty with regard to return on investment, coupled with Congress' directive that a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors."[13] Moreover, the Commission is not bound to implement PURPA in the same manner as other states.

Duke Energy has not provided any evidence that the state PURPA implementation policies they cited have successfully encouraged the development of QFs in those states. To the contrary, the entire state of Alabama, which Duke Energy referenced for its Alabama Power PURPA rates, has a total of only approximately 100

[12] Tr. Vol. II, p. 353, ln 20; p. 354, ln 1-5;p. 405, ln 16; p. 406, ln 1.
[13] Windham Solar at *8 (internal citations omitted).

MW of installed solar capacity. Tr. Vol. V, p. 118, ln 17-24. Duke Energy Witness Bowman also stated that North Carolina is an outlier that "significantly encourages QF development" compared to other states that offer only a variable avoided cost rates, including Virginia. Tr. Vol. II, p. 410, ln 9-14. Putting aside whether or not a variable avoided cost rate would comply with PURPA under Windham Solar, Dominion Witness J. Scott Gaskill responded to a question by Chairman Finley at the hearing regarding Dominion Virginia's "level of activity with respect to qualified facilities" in its Virginia service territory. Witness Gaskill responded that "[i]n terms of qualified facilities it would be minimal" citing "the differences in the implementation of PURPA from state to state." Tr. Vol. VI, p. 101, ln 19-24; p. 102, ln 2-4. The evidence presented in this proceeding has not demonstrated that the examples of state PURPA implementation Duke Energy has cited have encouraged QF development.

Additionally, Duke Energy has referred the Commission to tariffs that are available only for QFs up to 100 kW and are used in the context of rooftop or ground-mounted renewable energy systems used to serve a portion of the residential or commercial on-site load. This type of tariff is applied very differently than the Utilities' standard offer contract through which utility-scale QFs sell all or nearly all of their output to Duke Energy.[14] Duke Energy itself makes this general distinction between utility-scale QFs of 1 MW and greater and "smaller QFs seeking to install renewable or alternative energy facilities for primarily environmental or other non-commercial reasons." Tr. Vol. II, p. 385, ln 6-9. Comparing tariffs for small, primarily-rooftop solar QFs with contracts

[14] During the hearing, Duke Energy Witness Bowman conceded that Alabama Power's Rate PAE, cited in her Direct Testimony at p. 49, is only available to QFs up to 100 kW and that the tariff is primarily for customers with rooftop solar to use onsite and sell excess back to Alabama Power. Witness Bowman also cited a Georgia Power tariff – Solar Purchase Schedule SP-2 – that was discontinued in 2016.

for QFs up to at least ten times that size (1 MW under the Utilities' proposals) that sell most or all of their output to Duke Energy is an apples to oranges comparison.[15]

Witness Bowman referenced an additional Alabama Power tariff in rebuttal testimony that was approved after Duke Energy had filed direct testimony. This tariff offers annual rates for QFs above 100 kW.[16] The tariff did not undergo any formal review proceeding and was approved just two weeks after it was filed.[17] The Alabama PSC order approving the tariff makes reference to Windham Solar and FERC Order 688-A. However, the Alabama PSC's reference to "long-term" contracts based on these orders is misplaced. FERC Order 688-A implemented provisions related to Independent System Operator ("ISO") and Regional Transmission Organization ("RTO") wholesale markets for sales of capacity and energy for QFs larger than 20 MW. See FERC Order 688-A (implementing PURPA Section 210(m)).[18]

In contrast to FERC Order 688-A and Section 210(m), the FERC's treatment of contract duration in the context of LEOs is based on FERC regulation 18 C.F.R. § 292.304(d)(2)(ii) and FERC's orders implementing this regulation. Under the FERC's rules, QFs have the option to sell their output based on the "avoided costs calculated at the time the obligation is incurred" (i.e. through a LEO), and the FERC's LEO orders have emphasized that QFs selling under a LEO have the right to a long-term, forecasted

[15] As Duke Energy notes in testimony, customers in North Carolina may also participate in the net energy metering program for on-site renewable energy systems. Tr. Vol. II, p. 345, ln 13-14.
[16] Alabama Power Co., Petitioner, U-5213, 2017 WL 977573, at *5 (Mar. 7, 2017) (Duke Bowman Redirect Exhibit 1)
[17] Id. at 1.
[18] PURPA Section 210(m) provides an opportunity for utilities located in areas with certain types of wholesale markets (primarily ISOs and RTOs) to receive a waiver of their obligation to purchase output from QFs greater than 20 MW. The order referenced "wholesale markets for long-term sales of capacity and energy within the meaning of section 210(m)(1)(A)(ii)."

avoided cost rate that is long enough to allow QFs a reasonable opportunity to attract financing.[19]

Despite the Utilities' repeated appeal to examples of PURPA implementation in other states, the evidence has indicated that nearly every example the Utilities have presented has either failed to encourage QF development, applies only to smaller QFs, or misapplies FERC precedent. Instead, the Commission should continue to implement PURPA in a way that meets the goal of PURPA to encourage development of QFs.

5. The Utilities have not demonstrated that forcing QFs larger than 1 MW to negotiate contracts will encourage the development of QFs.

Duke Energy claims that QFs that do not qualify for the standard offer contract—QFs greater than 1 MW under Duke Energy's proposal—would still be able to enter into contracts with Duke Energy through bilateral negotiation. Tr. Vol, II, p. 347, ln 9-16; Tr. Vol. III, p. 77, ln 13-24; p. 78, ln 1-2. However, an option to "negotiate" a contract under terms that will prohibit QF development is no option at all. In E-100 Sub 140 the Commission recognized that "negotiating PPAs for projects that fall outside the standard tariff is a very challenging proposition." E-100, Sub 140 Phase 1 Order at 20. In the current proceeding, Public Staff Witness Hinton expressed continued concern regarding the challenges involved in contract negotiation, including "the unpredictability and often protracted nature of negotiating PPAs, along with the delays in the interconnection process." Tr. Vol. VIII, p. 61, ln 21-23. Witness Hinton also testified that while "QFs

[19] See e.g. Jd Wind 1, 130 FERC ¶ 61127 (Feb. 19, 2010)(stating that FERC has "consistently affirmed the right of QFs to long-term avoided cost contracts or other legally enforceable obligations with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred"); Hydrodynamics, Inc. 146 FERC ¶ 61193 (Mar. 20, 2014)(reiterating that QFs must receive "forecasted avoided cost rates"); Windham Solar (stating that a LEO must be "long enough to allow QFs reasonable opportunities to attract capital from potential investors").

maintain the right to petition for arbitration before the Commission, this process is also time consuming and adds significant transactions costs." Id. at 62, ln 2-4. NCSEA Witness Johnson, SACE Witness Vitolo, and NCSEA Witness Carson Harkrader expressed similar concerns regarding the bilateral negotiation process. Tr. Vol. VIII, p. 329, ln 2-4; p. 26, ln 14-22; p. 27, ln 1-9; Tr. Vol. VII, p. 380, ln 11-23; p. 381, ln 1-5.

Most problematic is Duke Energy's reduction of negotiated contract durations to five years, with the threat of further reduction to two years. During cross-examination, Duke Energy indicated that it currently offers only five-year negotiated contracts, decreased from 10-year terms. Tr. Vol. III, p. 37, ln 1-13. Duke Energy admitted that it is considering further reducing the negotiated contract duration, from five years to two years. Id. Such a drastic cut in contract duration exacerbates the already significant imbalance of power between the Utilities and QFs. This alone is enough to indicate that Duke Energy's negotiation practices have become more, not less, burdensome since the last avoided cost proceeding.

Duke Energy's argument that providing a standardized set of Duke-proposed terms and conditions will suffice falls short when paired with such drastic reductions in contract lengths. Tr. Vol. II, p. 348, ln 7-22; p. 389. The Utilities suggest that solar project developers have become more sophisticated in recent years. Tr. Vol. II, p. 344, ln 16-21; Tr. Vol. V, p. 148, ln 11-13. Despite these purported improvements, no QF, regardless of the "sophistication" of the developer, will be able to negotiate a viable and financeable contract if the Utilities are unwilling to negotiate on a contract length of sufficient duration, or if the Utilities impose additional burdensome, non-negotiable terms.

Duke Energy has also indicated that it intends to incorporate solar integration costs into its negotiated contracts. Tr. Vol. III, p. 74-75; Tr. Vol. II, p. 394, ln 6-13. The Commission determined in E-100, Sub 140 Phase 1 that it was "premature for the Utilities to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates." E-100, Sub 140 Phase 1 Order at 10. In this proceeding, Duke Energy has not incorporated solar integration costs and benefits into their proposed standard offer avoided cost rates, and the parties to this proceeding have not presented evidence on the appropriate method by which to incorporate any potential integration costs and benefits. During cross-examination, Duke Energy indicated that it believes it is appropriate to incorporate integration costs into negotiated contracts, but it admits that it has not established how those integration costs would be calculated. Tr. Vol. III, p. 74-75.

If the Commission determines it is now appropriate to consider costs and benefits of solar integration into avoided cost rates, the Commission should require the Utilities to propose integration methodologies and calculations and allow input from Public Staff and other interested stakeholders. If not, it appears that the Utilities may unilaterally establish and impose additional costs on QFs without first having those figures adequately vetted by the Commission.

As Chairman Finley noted during his examination of the Duke witness panel, Duke Energy's contract negotiation process would take place on a QF-by-QF basis. The Utilities' proposals have injected a significant level of uncertainty into the negotiation process moving forward. This uncertainty is magnified by the fact that, under the Duke Energy proposals, virtually all utility-scale solar development would likely be pushed into contract negotiations, which the evidence indicates would not be a viable option for QFs. Although each QF has the option to pursue arbitration or to file a complaint with the Commission if it is unable to successfully negotiate a contract with the Utilities, additional contested negotiations would increase the administrative burden and expenses for the Utility, the QF, and the Commission.

As discussed below, Duke Energy has proposed a competitive solicitation process as an alternative option for QFs to sell output. However, there is no indication of when, how, or if such a process would materialize. Particularly in light of this ambiguity, the Commission should reject the Utilities' latest efforts to discourage QF development. Maintaining the current 5 MW, 15-year standard offer contracts will continue to encourage QF development in North Carolina, consistent with the goal of PURPA Section 210. Until the Utilities have demonstrated that they are able to engage in successful bilateral negotiations with QFs less than 5 MW on terms that permit reasonable opportunities to attract financing, the Commission should maintain the current 5 MW, 15-year standard offer contract.

6. Duke Energy has provided inadequate detail about its proposed competitive solicitation process.

Duke Energy has proposed a hypothetical competitive solicitation process as an alternative to purchasing QF output through standard offer contracts or through bilateral negotiations.[20] Duke Energy anticipates any such competitive solicitation process developing through a future Commission proceeding, and they acknowledge a significant lack of specific details about how and when a potential competitive solicitation process would be implemented. Tr. Vol. II, p. 52; Tr. Vol. III, p. 80-81.

[20] See DEP and DEC Joint Initial Statement and Exhibits, p. 4.

Duke Energy has proposed sweeping PURPA changes in exchange for the vague promise of a competitive solicitation process with few details. Duke Energy's PURPA proposals would result in shifting the utility-scale solar QF market to a system in which bilateral negotiations would be the primary vehicle for QFs to attempt to sell their output.[21] However, the Utilities have not demonstrated that these contract negotiations will provide a sufficient avenue through which QFs ineligible for the standard offer contract may sell their output. Granting the Utilities' proposed changes to the standard offer contract—particularly lowering the contract availability threshold to 1 MW; decreasing the contract duration to 10 years; and updating avoided cost prices every two years—without knowing how, when, or if a competitive solicitation process would take shape, would be contrary to the letter and the spirit of PURPA to encourage QF development.

Moreover, any future competitive solicitation process applicable to QFs would be required to comply with PURPA and the FERC's implementing regulations. Duke Energy has described a competitive solicitation process as "outside of [the] context" of PURPA. Tr. Vol. V, p. 70, ln 4-6. However, unless Duke Energy has received a waiver of their purchase obligation from the FERC, any QF may choose to sell its output to an electric utility and avail itself of the requirements and protections of PURPA.[22] FERC has previously addressed the use of competitive solicitations in the context of PURPA.

The FERC's 2014 order, Hydrodynamics, Inc. 146 FERC ¶ 61,193 (2014), (cited in Tr. Vol. II, p. 357) primarily addresses a Montana utility's competitive solicitation

[21] Duke Energy has described the 1 MW threshold as a good proxy between utility-scale projects larger than 1 MW and smaller renewable energy projects. Tr. Vol. II, p. 345, ln 6-12.
[22] PURPA Section 210(m) permits state regulatory authorities or nonregulated electric utilities to petition FERC for a waiver of a utility's mandatory purchase obligation in certain circumstances.

process under PURPA. In Hydrodynamics, a Montana regulation allowed QFs larger than 10 MW to secure a long-term contract at the applicable avoided cost rates only after winning a competitive solicitation. Outside of the competitive solicitation process, QFs were only able to negotiate bilateral contracts with the utility. The FERC reiterated its long-standing requirement that QFs may choose whether to sell their output "as-available" or subject to a LEO. The FERC held that "requiring a QF to win a competitive solicitation as a condition to obtaining a long-term contract imposes an unreasonable obstacle to obtaining a legally enforceable obligation particularly where…such competitive solicitations are not regularly held."[23] The FERC additionally stated that with respect to contract negotiation, the regulation at issue created "a practical disincentive to amicable contract formation because a utility may refuse to negotiate with a QF at all and yet the [regulation] precludes any eventual contract formation where no competitive solicitation is held." Id. at P 33.

Duke Energy's lack of information regarding a potential competitive solicitation process does not provide the Commission adequate detail to assess whether or not such a competitive solicitation in North Carolina would comply with PURPA. Duke Energy Witness Bowman stated at the hearing that Duke Energy does not know how often they would hold competitive solicitations and that the Commission would determine the proper competitive solicitation frequency. Tr. Vol. III, p. 80, ln 22-24; p. 81, ln 1-9. Witness Bowman also indicated that under the competitive solicitation process envisioned by Duke Energy, QFs that were not selected through the solicitation process would only be able to sell their output if they were able to negotiate a contract with the Company. Tr. Vol. III, p. 79, ln 20-24; p. 80, ln 1-5.

[23] Hydrodynamics, Inc. at P 32.

Duke Energy has plainly stated that it does not yet know how a potential competitive solicitation process would be structured. Because of this uncertainty—and in light of the fact that Duke Energy has proposed to fundamentally change the PURPA market in North Carolina by shifting almost exclusively to bilateral negotiations—the Commission should not consider a competitive solicitation process as a viable alternative to existing North Carolina PURPA implementation until such a process has been approved after a separate stakeholder proceeding. Additionally, PURPA requires that QFs still have the opportunity to sell their output under forecasted rates outside of any competitive solicitation process that may be established. The Commission should ensure that the standard offer contracts will meet these requirements.

B. Proposed Changes to Avoided Cost Calculations and Parameters

1. Duke Energy's proposal to limit capacity value in certain years fails to comply with the peaker method and discriminates against QFs.

Duke Energy has proposed to undervalue avoided capacity in this proceeding by including zero values in certain years of its planning horizon. This proposal not only fails to comply with the peaker method, but also discriminates against QFs. The Commission has previously rejected similar requests by the Utilities, ruling that implementation of the peaker method involves assigning a capacity value in each year of the Utilities' analysis. See, e.g., E-100, Sub 140 Phase 1 Order at 35. The Commission should uphold its previous ruling and deny Duke Energy's proposal.

The peaker method requires a utility to determine the dollar-per-kilowatt cost of building a combustion turbine ("CT") and to spread those costs over the expected lifetime of the peaker unit. This method results in an annualized avoided capacity cost. Unlike some other methods for calculating avoided capacity, the peaker method does not follow the timeline of the utility's latest integrated resource plan ("IRP") and does not depend on the utility's next planned capacity addition in its IRP. Failing to assign capacity value in certain years is thus inconsistent with the peaker method, which includes a value each year as part of the calculations. As pointed out by Witness Vitolo: "[t]he rationale to use the dollar-per-kilowatt cost of a CT and making a capacity payment in every year are inextricably linked." Tr. Vol. VII, p. 47, ln 6-7.

Public Staff has made this exact point in previous biennial avoided cost proceedings. As noted by SACE Witness Vitolo in his testimony, Public Staff provided the following explanation in the E-100 Sub 140 proceeding: "including zeroes in the calculation of avoided capacity costs or paying capacity payments only when reserve margins are low does not comport with [the peaker] theory." Tr. Vol. VII, p. 48, ln 6-8 (quoting Public Staff Witness Hinton's testimony). Public Staff has changed its position in this proceeding, but still admits that Duke's proposal is a "departure from the peaker method." Tr. Vol. VIII, p. 30, ln 5. The Commission should not accept the Public Staff's attempt to deviate from the Commission's peaker method as a means by which to reduce avoided cost rates.

Duke Energy's proposal to assign a zero capacity value in certain years should be rejected not only because it departs from the peaker method, but also because it would result in differential treatment between the utility and QFs. As noted by NCSEA Witness Johnson, the buildout of traditional large-scale utility capacity is "lumpy" in character. As a result, utilities often build far more generation capacity than is required in the early years of the plant. This means that ratepayers pay the utility for significantly more generation capacity than is needed until the demand catches up with the generation addition. Tr. Vol. VIII, pp. 294-296. As noted in the Commission's description of witness testimony in the E-100, Sub 140 proceeding, if a utility's proposal to assign zero capacity value in certain years was approved, it would encourage "utilit[ies] to over-plan and over-build in order to maximize revenues and profits." E-100, Sub 140 Phase 1 Order at 34 (summarizing Witness Hornby's testimony). The Commission took these considerations into account in 2014 when it determined that including zeros for certain years of the avoided capacity calculations "lowers the avoided cost rate for the entire 15-year period" and the "resulting avoided cost rates may not equal the full cost of a CT and system marginal energy costs as a proxy for a baseload plant, as intended by the peaker method." E-100, Sub 140 Phase 1 Order at 35. The same concerns warrant rejecting Duke Energy's proposal to include zero capacity values for certain years in this proceeding.

2. Dominion's proposal to completely eliminate capacity payments is inconsistent with the peaker method, discriminates against QFs, and is inappropriate in light of Dominion's system-wide planning.

Dominion's proposal to completely eliminate avoided capacity payments should be rejected as inconsistent with the peaker method, discriminatory to QFs, and inappropriate given the utility's system-wide planning across both North Carolina and Virginia. Dominion proposes to "set the avoided capacity rate to zero to reflect the fact that additional Solar [Distributed Generation] in North Carolina will not enable the Company to avoid additional capacity costs either in North Carolina or elsewhere on DNCP's system." Tr. Vol. V, p. 144, ln 1-3.

The utility's rationale for eliminating capacity payments is flawed. As discussed above, including zeros in certain years (or all years, as proposed by Dominion) of the planning horizon is fundamentally inconsistent with the Commission's approved peaker method. Moreover, Dominion's assertion that it has no capacity need that solar DG could help meet is incorrect. As pointed out by SACE Witness Vitolo, Dominion has both wintertime and summertime peaks. Even if the solar contribution to wintertime peaks is assumed to be relatively small, solar still provides Dominion "an ability to defer or avoided capacity related costs, as well as sell additional surplus generation capacity in PJM's Reliability Pricing Model (RPM) capacity market." Tr. Vol. VII, p. 50, ln 12-14. Dominion Witness Petrie pointed to a PJM Manual to show that an "acceptable offer" for solar firm capacity would be in the 0-20% range. Even this low value is greater than zero, and other PJM materials demonstrate a higher value for solar capacity. For example, PJM's class average capacity value of solar in January 2017 was listed at 38 percent. Tr. Vol. VIII, p. 51, ln 8. In either case, it should not be assumed that solar QFs (or any other QFs) provide zero capacity value.

There is additional evidence that Dominion has capacity needs in the next 10-15 years which should be reflected in its avoided cost rates. Dominion's IRP shows a capacity need beginning in 2022, and updated resource planning still demonstrates a need beginning in 2024. Tr. Vol. V, p. 224, ln 3-11. Unexpected capacity needs can also arise. Just this year Dominion encountered an unanticipated capacity need. As discussed by Dominion witnesses on cross examination, the Roanoke Valley Power facility was deactivated from PJM on March 1, 2017. The capacity provided to Dominion by that facility was guaranteed through 2019, and when the Roanoke facility deactivated, Dominion "had to procure replacement capacity, capacity performance, … through May 31, 2019." Tr. Vol. VI, pp. 56-57. If Dominion was allowed to completely eliminate avoided capacity payments, not only would it undermine the Commission's approved peaker method, it would also fail to properly account for these types of unexpected capacity needs.

Finally, Dominion asserts that it no longer has a capacity need in its North Carolina territory because the Dominion system is saturated by solar facilities. However, Dominion witnesses admitted on cross examination that in addition to being part of PJM, Dominion's system planning is not limited to North Carolina or Virginia in isolation. Tr. Vol. VI, p. 59, ln 12-20. Rather, the utility engages in joint planning across both states. Id. Public Staff Witness Hinton similarly pointed out this flaw in Dominion's request:

> DNCP's proposal to assign no capacity value to future QF generation because there is more generation in DNCP's North Carolina Service territory than load seems to run counter to general principles of utility system planning. Utility planning is not performed on a state-by-state basis; rather, the generation and transmission systems are planned on a system-wide basis. … I do not find the Company's argument that there is no capacity value associated with incremental QF generation as reasonable.

Tr. Vol. VIII, p. 34, ln 14-19; p. 35, ln 8-10.

A purported lack of capacity need in North Carolina does not necessarily indicate that there is no capacity need or value added to the system as a whole across both states, particularly considering Dominion's participation in the PJM market. For the reasons discussed above, Dominion should be required to calculate and provide an avoided capacity rate in this proceeding.

3. Duke Energy's proposal to reduce the Performance Adjustment Factor to 1.05 fails to fully compensate QFs, conflicts with the Commission's prior rulings, and discriminates against QFs.

As with the Utilities' proposals to reduce or eliminate capacity values in certain years, DEC and DEP have raised yet again a familiar proposal to reduce the performance adjustment factor ("PAF") for QFs. Since 1990, the Commission has approved a performance adjustment factor for capacity credits. See Tr. Vol. VIII, pp. 36-37. The purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive payments for avoided capacity as approved by the Commission. Id.; see also E-100, Sub 140 Phase 1 Order. As noted by Public Staff Witness Hinton, "PURPA discourages discrimination between the utility and a QF; as such, the QF deserves a reasonable opportunity to collect its full capacity payment." Tr. Vol. VIII, p. 38, ln 10-13.

The current PAF of 1.2 for QFs other than run-of-river hydro allows a QF to receive the full avoided capacity costs if it operates for 83% of on-peak hours. The Commission has previously determined that an availability of 83% for these QFs is reasonable and if a QF is operating for that amount of time, it should be allowed to recover the full avoided capacity costs. As in many prior proceedings, Duke Energy seeks to reduce the PAF from 1.2 to 1.05, meaning that a QF would need to be available 95% of the time in order to receive its full capacity credit. Reducing the PAF would negatively impact QF avoided capacity recovery and thus discourage QF development. See, e.g., Tr. Vol. VIII, p. 302, ln 1-12. Duke Energy argues that the PAF should be reduced to 1.05 because this more closely correlates with the availability of a CT unit. See Tr. Vol. II, p. 309, ln 20-22; pp. 192, 193, 195. The Commission has consistently rejected this argument in past proceedings.

The Commission most recently denied a request to reduce the PAF in 2014. The Commission reiterated that "[t]he availability of a CT is not determinative for purposes of calculating a Performance Adjustment Factor (PAF) because the fixed costs of a peaking unit in the peaker method employed by the Commission are a proxy for the capacity-related portion of the fixed costs of any avoided generating unit." E-100, Sub 140 Phase 1 Order at 9. Again in this proceeding, Duke has proposed to reduce the PAF from 1.2 to 1.05 for non-hydro QFs. The Commission's reasoning for rejecting this proposal applies today just as it did in the 2014 proceeding, and in proceedings before it.

The Commission's reasoning for rejecting proposals to reduce the PAF is supported by multiple witnesses in the current proceeding. SACE Witness Vitolo testified:

> the only specific role for a combustion turbine in the peaker method is to estimate the avoided capacity cost ($/kW-yr) for a new unit. There is no expectation that the QF will avoid the utility procurement of a specific generator technology or type. … [I]n any given hour, the QF could be displacing a peaking unit, a mid-range unit, a mid-range unit, or even a baseload unit – demonstrating that the QF's availability should be compared to the utility's entire fleet.

Tr. Vol. VII, p. 43, ln 7-13. Public Staff Witness Dustin R. Metz likewise testified that the reliability of a CT is not appropriate for calculating the PAF. He explained that "[t]he peaker methodology uses a CT as a proxy for the pure capacity value of generation versus the energy value, but it is not meant to imply that all QF capacity calculations should be based on the characteristics of a CT." Tr. Vol. VIII, p. 126, ln 17-20. NCSEA Witness Johnson bolstered these points: "Under the Peaker Method as historically interpreted and implemented by this Commission, it is more appropriate to focus on availability data for <u>all types of units</u>, including coal units and combined cycle units." Tr. Vol. VII, p. 298, ln 7-10 (emphasis in original). NCSEA Witness Johnson explained that this is because "in the Peaker Method, the fixed costs of a peaking unit are used as a proxy for the capacity-related portion of the fixed costs of all units, including baseload units." Id.

A review of Duke Energy's generation feet reveals a lower availability than the 95% the utilities seek to impose on QFs. Witness Hinton testified that Public Staff agreed with the Commission's prior ruling that "if a QF's availability is similar to that of the utility's baseload fleet, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs." Tr. Vol. VIII, p. 39, ln 8-10. Public Staff examined the utilities' baseload and intermediate generating unit availability over the past five years and found that the average availability over that time frame was approximately 86.33%. This rate corresponds to a 1.16 PAF, which Public Staff recommends. Id.; Tr. Vol. VIII, p. 127, ln 2-3.

SACE Witness Vitolo testified that, in addition to the average availability of baseload units, it is also important to consider the range of availability of utility-owned generation plants. This should specifically include recognition of those plants that are least available in the utilities' generation fleets, but for which the utilities are still allowed their own full capacity cost recovery. As admitted by Duke Witness Snider on cross examination, and demonstrated in SACE Duke Panel Cross Examination Exhibits Numbers 3 and 4, there are many generation units in Duke Energy's fleet that have an annual availability of less than 86% and 83%. Tr. Vol. III, p. 112-119; SACE Duke Panel Cross Examination Exhibits Numbers 3 and 4. These include, but are not limited to Robinson 2 (84%), the Lee Energy Complex STI (83.01%), Richmond County Combined Cycle 8 (83.97%), Roxboro steam units 3 and 4 (72.71% and 77.73%, respectively), and the Rockingham CT (85.08%). Id. Witness Snider further admitted that Duke Energy gets full cost recovery for these units, even when their availability is less than 86 or 83%. Id.

In rebuttal testimony, Witness Snider attempted to raise a new and different rationale, departing from his previous reliance on CT availability. According to Witness Snider, a 1.05 PAF approximates availability of a general baseload unit, when the analysis is limited to on-peak hours. This new explanation conveniently arrived at the same conclusion Duke Energy has sought previously (a 1.05 PAF). As pointed out by Public Staff on cross examination, the intervenors in this proceeding have not had an opportunity to vet, evaluate, and respond to Witness Snider's new rationale. See, e.g., Tr. Vol. VIII, pp. 187-188, 190-191. Public Staff further questioned whether limiting an availability analysis to on-peak hours alone is an appropriate consideration, particularly because QFs of different types can provide power during both on-peak and off-peak hours. Id. Without further analysis from Duke Energy and an opportunity for intervenors to vet and respond to it at the outset of a future avoided cost proceeding, this new eleventh hour rationale should be rejected as premature and unsupported by the evidence in this proceeding.

Given the Public Staff's findings, and the evidence that there are plants operating even less than 86% and 83% of the time, it is appropriate for the Commission to maintain its longstanding precedent of a 1.2 PAF for QFs other than run-of-river hydro facilities.

4. Duke Energy's proposed 80/20 seasonal split is premature and inappropriate.

As described by Witness Snider, Duke Energy is seeking to incorporate a new weighting of summer and winter capacity hours, with an 80 percent weight on winter hours and a 20 percent weight on summer hours. This is a reversal from the seasonal weighting in prior proceedings, and it should be rejected as premature and inappropriate at this time.

Duke Energy's proposal is based on resource adequacy studies conducted by Astrape Consulting for DEC and DEP in 2016 ("Astrape Reports"). The Astrape Reports showed an increase in potential reliability issues in the winter season, leading Duke Energy to place a greater emphasis on winter-time system planning. However, the Astrape Reports and Duke Energy's proposal raised a number of concerns by intervenors, in both this proceeding and in the Duke Energy Integrated Resource Planning proceeding. As described by Witness Hinton, "Public Staff continues to have concerns that the proposed seasonal factors may shift an excessive emphasis toward the winter periods than appropriate." Tr. Vol. VIII, p. 41, ln 14-16. Witness Hinton reiterated concerns from the IRP proceeding, that "the shift of DEC and DEP from summer to winter-peaking should not diminish consideration of the summer peak, which remains significant." Tr. Vol. VIII, p. 41, ln 20-23; p. 42, ln 1.[24] NCSEA Witness Johnson noted that Duke Energy's proposal "is a drastic change from the last biennial proceeding," and recommended that the Commission reject the proposal. Tr. Vol. VII, p. 307, ln 6.

SACE Witness Vitolo also raised concerns about the Astrape Reports and Duke Energy's proposal to shift seasonal allocations to an 80/20 winter/summer split. First, the Astrape Reports gave too much weight to recent atypical weather experienced during the 2014 and 2015 winters, as described by SACE Witness Vitolo. Tr. Vol. VII, p. 54, ln 11-12. The analysis in the Astrape Reports was limited to the last five years of weather data and load, neglecting 36 historical weather years of collected data in the final analysis. The 2014 and 2015 winters were atypically cold and impacted by the "polar vortex"

[24] Public Staff recommends a less extreme shift to a 40/60 summer/winter allocation.

phenomenon. By narrowing the focus and prioritizing recent years with extremely cold winters, the Astrape Reports results were skewed to overemphasize a need for more winter-peak planning. The flawed results showed an increase in the number of potential reliability issues during the winter months. Duke Energy has relied on these studies to justify a shift to more winter-season planning and to propose a shift in seasonal weighting in this proceeding.

Second, the Astrape Reports were developed for one target year: 2019. SACE Witness Vitolo testified that applying the 2019 results across the planning horizon applies a narrow finding far too broadly. Tr. Vol. VII, pp. 55-56. It is inappropriate for Duke to apply the Astrape Reports result over every year of the long-term avoided cost contract, particularly when the reports weighed too heavily on atypical winter weather in recent years.

Finally, the Astrape Reports fail to account for any future adjustments Duke Energy may undertake to address wintertime peaks. For example, the Astrape Reports assume Duke Energy's 2016 IRP values for energy efficiency and demand-side management capacity. Witness Vitolo testified that this fails to account for any future planning that Duke Energy may undertake to adjust energy efficiency and demand-side management programs to more directly reduce wintertime peaks, in addition to summertime peaks. The reports also fail to account for Duke Energy's ability to procure additional wintertime capacity through bilateral agreements or interconnection with facilities in PJM. Tr. Vol. VII, pp. 55-56.

The Astrape Reports show that beginning in 2019, wintertime capacity may become more valuable to Duke Energy to address reliability planning. However, the lack of information about 2017 and 2018 and the flaws in the study, including overemphasis of recent atypical cold weather events, make Duke Energy's proposal for a complete reversal on seasonal allocations premature and inappropriate at this time. Furthermore, Duke Energy acknowledged that concerns have been raised about the reports and that it is continuing to study the issue. Tr. Vol. III, p. 119, ln 13-24; p. 120, ln 1-2; p. 124, ln 6-11. The Commission should reject Duke Energy's proposal to implement a 20/80 summertime/wintertime seasonal allocation. In particular, the Commission should maintain the existing summertime/wintertime seasonal allocations until at least 2019 and should require Duke Energy to correct the flaws in the Astrape Reports. In the alternative, the Commission should establish a more modest shift in seasonal allocation that accounts for the uncertainty around the Astrape Reports and Duke Energy's seasonal planning going forward. As summarized by Public Staff Witness Hinton:

> Duke is continuing to refine its load forecasting capabilities to better understand the growth and impact of DEC's and DEPs winter and summer peaks. Until a pattern of winter peaks is better understood and there is more confidence that the Company is a winter peaking utility, shifting to a predominantly winter-centric paradigm may be premature.

Tr. Vol. VIII, p. 42, ln 1-6.

5. <u>Dominion's elimination of line loss adjustment should be rejected as premature and inappropriate.</u>

Dominion's proposal to completely eliminate its 3% line loss adjustment should be rejected as premature and unwarranted. Dominion proposed to eliminate the line loss adder "[d]ue to the saturation of distribution-level QFs relative to load." Tr. Vol. V, p. 143, ln 16-17. In support of this claim, Dominion provides charts of distribution feeders in its North Carolina territory, showing that there have been instances of electricity backflowing onto the transmission lines. According to Dominion Witness Gaskill, 11 of

Dominions' 33 transformers in North Carolina "show a predominantly constant backflow of power, indicating that energy delivered from the distributed generation connected at these substations exceeds the load." Tr. Vol. V, p. 150, ln 13-16. In other words, Dominion's argument is that because solar QF projects are resulting in *some* backflow onto transmission lines on *some* circuits, *some* of the time, that there are no line losses being avoided at all by QFs on Dominion's electricity grid.

Dominion's argument falls flat. Witness Vitolo observed in his testimony and on cross examination that Dominion has cherry-picked its data in order to argue that QFs never contribute to line loss avoidance. Witness Vitolo analyzed the raw data from Dominion's substations and found that line loss avoidance was occurring far more often than represented by Witness Gaskill.[25] Witness Vitolo found that the addition of a solar QF would still contribute to line loss avoidance at 32 of Dominion's 33 substations. This analysis demonstrates that QFs in Dominion's territory continue to reduce energy losses over distribution and transmission lines, and Dominion's line loss adjustment should reflect those line losses.

Dominion admitted on cross examination that it has the capability to do a more detailed line loss analysis, and that it could even determine QF-specific line losses. Tr. Vol. VI, pp. 38, 53, 89. Dominion Witness Gaskill further admitted that the company has not calculated line losses associated with QFs in times when backflow was and was not occurring, even though some studies are apparently ongoing. Tr. Vol. VI, pp. 53-54. Despite Dominion's ability to quantify line losses more granularly, the utility has instead

[25] SACE Witness Vitolo testified that he disregarded consecutive measurements of "0.000" in the dataset "because those measurements almost certainly represent sensor failure and not perfectly balanced power flow in that portion of the distribution circuit." Tr. Vol. VII, pp. 59.

sought to completely eliminate the line loss adjustment, without a quantitative analysis and while cherry-picking its data to overstate the amount of backflow taking place.

Additionally, SACE Witness Vitolo pointed out that even where a substation experiences backflow at certain times, if the overall load on the transmission lines is reduced, line losses are still avoided. Tr. Vol. VII, p. 58, ln 14-18. He provided an example:

> if a substation has 8 MW of load at a given hour and has a QF producing at 10 MW at that hour, there will be approximately 2 MW of backflow. In this situation, despite Witness Gaskill's claims, there is a *line loss reduction* because the transmission grid observes a net reduction of 8 MW of total demand in that hour.

Id. Thus, even when a substation has backflow at certain times, a QF can still avoid the line losses associated with any net reduction in demand on the transmission lines.

This line loss avoidance should be accounted for in Dominion's line loss adjustment. But rather than providing a detailed and accurate analysis of its actual line loss factor, Dominion has inappropriately asked the Commission to completely eliminate a line loss adjustment. This request should be rejected unless and until Dominion provides additional calculations and evidence regarding a revised and accurate line loss factor (rather than seeking to eliminate it altogether). The evidence presented in this proceeding does not support Dominion's proposal.

Although Public Staff stated that "[a]t a system level, DNCP has demonstrated that its North Carolina electric grid is experiencing reverse power flows onto its transmission system from DG," Public Staff also has not completed any detailed analysis of what the line losses are currently or what they may be in the future. Tr. Vol. VIII, p. 130, ln 16-18. Public Staff further recommends that Duke Energy provide a line loss study in the next avoided cost proceeding. It is unclear why Public Staff would support Dominion's proposal without requesting or requiring that it provide a similar detailed analysis of the connection between increased DG and lines loss changes.

As recommended by SACE Witness Vitolo: "The Commission should require DNCP to calculate line loss avoidance with sufficient granularity to compensate renewable QFs for the value those QFs provide with respect to line loss avoidance. Should DNCP lack the ability to study line loss avoidance with sufficient granularity, it should continue using the 3 percent line loss avoidance value." Tr. Vol. VII, p. 60, ln 18-21. As admitted by Dominion witnesses on cross examination, Dominion is capable of doing this kind of granular analysis. Tr. Vol. VI, pp. 38, 53, 89. Given the current lack of detailed analysis from Dominion and Public Staff, allowing Dominion to completely eliminate the line loss adder is inappropriate and premature at this time.

C. LEO, Curtailment, and Grid Integration Issues

1. Duke Energy's proposed LEO standard does not comply with PURPA.

In its Joint Initial Statement and Exhibits, Duke Energy proposed to add a new element to the existing LEO requirements. DEP and DEC Joint Initial Statement and Exhibits, p. 31-33. Existing LEO requirements include: 1) self-certifying as a QF with FERC; 2) submitting an approved Notice of Commitment ("NoC") Form; and 3) obtaining a Certificate of Public Convenience and Necessity ("CPCN"). Duke Energy proposed in its initial statements an additional requirement: that QFs complete an interconnection System Impact Study (or be exempt from it) prior to a LEO taking effect. Id. at 32.

In direct testimony, Duke Energy amended its initial LEO proposal. Under the revised proposal, larger QFs ineligible for the standard offer contract (greater than 1 MW under Duke Energy's proposals) would be required to enter into negotiations with Duke Energy, agree upon the terms of the contract, and sign a final draft executable PPA before a LEO is established. Tr. Vol. II, p. 454, ln 2-8. QFs eligible for the standard offer contract would 1) submit a Report of Proposed Construction; 2) submit a Section 2 or Section 3 Interconnection Request approved by the Company; 3) indicate the intent (i.e., a notice of commitment) to sell the QFs output to DEC or DEP under the then-approved standard avoided cost rates subject to the terms of the tariff. Tr. Vol. II, p. 452, ln 14-15, p. 453, ln 1-5. For the reasons discussed below, the Commission should reject both Duke Energy's initial and amended LEO proposals.

In FLS Energy, Inc., 157 FERC ¶ 61,211 (2016), FERC discussed its prior rulings on permissible LEO requirements. FERC cited Cedar Creek Wind, LLC, 137 FERC ¶ 61,006, at P 36 (2011) which "explained that the term 'legally enforceable obligation' is broader than simply a contract between an electric utility and a QF, and that a state may not limit the methods through which a legally enforceable obligation may be created to only a fully-executed contract." FLS Energy at P 24 (emphasis added).

In FLS Energy FERC also held that because the Montana rule allowed the utility to "delay the facilities study and the tendering to the QF of an executable interconnection agreement, the requirement of an executed interconnection agreement imposed by the Montana Commission is no different than requiring a utility-signed contract." Id. at P 26 (emphasis added).

FERC's 2014 Hydrodynamics, Inc. ruling (cited in Tr. Vol. II, p. 357) also addressed the LEO standard. In that order, FERC again referenced its prior orders on the LEO standard, stating that, "[i]n Grouse Creek, the Commission found that the Idaho Commission's requirement that a QF file a meritorious complaint to the Idaho Commission before obtaining a legally enforceable obligation 'would both unreasonably interfere with a QF's right to a legally enforceable obligation and also create practical disincentives to amicable contract formation.'" Hydrodynamics at P 32 (citing Grouse Creek Wind Park, LLC, 142 FERC ¶ 61,187, at P 40 (2013))(emphasis added).

On cross-examination, Duke Energy Witness Freeman testified that under the Duke Energy's LEO proposal, a QF must enter into a PPA before a LEO is established. Tr. Vol. III, p. 46, ln 15-20. Witness Freeman admitted that the interconnection study process is "ultimately within the Companies' control" and Duke Energy will not face any penalties if Duke delays sending a system impact study to the QF. Tr. Vol. II, p. 465, ln 11-12; Tr. Vol. III, p. 46, ln 12-14. Finally, Witness Freeman stated that under Duke Energy's modified LEO proposal, if a QF was unable to enter into a PPA, the QF could seek arbitration before the Commission to determine when the LEO was established. Tr. Vol. III, p. 48, ln 19-23.

Duke Energy's testimony indicates that its proposal would run afoul of prior FERC rulings regarding the LEO standard. First, FERC has clearly indicated that requiring an executed PPA as a pre-requisite to a LEO is impermissible. Cedar Creek Wind, LLC, 137 FERC ¶ 61,006, at P 36 (2011). Duke Energy's proposal would require the QF and Duke Energy to agree to all material contract terms. QFs unable to reach agreement would be required to enter into arbitration or file a complaint with the

Commission. Tr. Vol. II, p 454, ln 14-18. However, this uncertainty – and the uneven bargaining power of Duke Energy under this proposal – is exactly what the FERC's LEO requirements were designed to prevent.

Duke Energy's proposal would permit it to delay the system impact study without penalty, allowing Duke Energy to control whether and when a LEO is created. Although a QF could theoretically seek arbitration before the Commission to determine when a LEO was established, the FERC has indicated that requiring a QF to file a complaint with the state regulator interferes with a QFs right to a LEO and creates a disincentive to successful contract negotiation. For these reasons, the Commission should reject Duke Energy's LEO proposals.

2. Duke Energy's proposal to expand the definition of "system emergency" does not comply with PURPA.

Underlying the Utilities' proposals in this proceeding to change the availability of the standard offer contract is the narrative that, as a result of a "surge" of solar QFs, the Utilities may be unable to effectively integrate solar QFs onto the grid without facing operational challenges.[26] Despite a range of other tools and methods to address these concerns, Duke Energy seeks to discourage QF development through changes to the standard offer contracts and additionally proposes to broaden their ability to curtail QF power. According to Witness Bowman, Duke Energy seeks to broaden curtailment by amending its standard offer Terms and Conditions to expand "the circumstances that are considered 'an emergency condition'" including "any circumstance that requires action

[26] E.g. Tr. Vol. II, p. 27, ln. 12.

by Duke Energy to comply with NERC/SERC Reliability Corporation regulations or standards." Tr. Vol. II, p. 359, ln 14-19; p. 415, ln 17-21.[27]

As Duke Energy and Public Staff witnesses note, PURPA provides limited opportunities for utilities to curtail QFs, including in system emergencies under 18 C.F.R. § 292.307(b). Tr. Vol. II, p. 364, ln 17-20; Tr. Vol. VIII, p. 122, ln 5-11. FERC regulations define a "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." DEP and DEC Joint Initial Statement and Exhibits, p. 20, n. 20 (citing 18 C.F.R. § 292.101(b)(4)).

Although Duke Energy asserts that an imminent violation of a NERC BAL standard constitutes a system emergency, they have cited no statute, regulation, or FERC order indicating that their proposed definition complies with the FERC's definition of "system emergency." Public Staff Witness Dustin R. Metz testified that "neither the Federal Code nor any FERC ruling has expressly stated that an imminent violation of a NERC BAL Standard constitutes a system emergency…." Tr. Vol. VIII, p. 122, ln 15-17. Despite this acknowledgement, Witness Metz went on to say that he believes an imminent violation of the BAL Standards would constitute a system emergency. Witness Metz then stated that because he considers an imminent violation of a NERC BAL Standard to constitute a system emergency, it would constitute a system emergency under 18 C.F.R. § 292.307(b). Id., ln 6-9. However, this circular reasoning is not based upon any legal interpretation of the FERC regulation.

Neither Duke Energy nor Public Staff adequately apply the FERC's definition of "system emergency" which is "a condition on a utility's system which is likely to result

[27] DEP and DEC Joint Initial Statement and Exhibits, DEC Exhibit 4, p 9-10; DEP Exhibit 4, p. 8-9.

in imminent significant disruption of service to customers or is imminently likely to endanger life or property." [28] The parties have not presented substantial evidence that an imminent violation of a NERC BAL standard is "likely to result in imminent significant disruption of service to customers." The parties also have not presented substantial evidence that an imminent violation of a NERC BAL standard is "imminently likely to endanger life or property." As a result, Duke Energy's proposed amendment to its Terms and Conditions does not comply with PURPA and FERC regulations, and the Commission should reject it.

If the Commission ultimately determines that some level of curtailment is necessary for grid reliability and operations at this time, a take-or-pay curtailment provision would ensure that any curtailment is fair to both Utilities and QFs.[29] A take-or-pay provision would provide Duke Energy with the control it desires while preventing financial harm to QFs, consistent with the policy goals of PURPA. As discussed below, Duke Energy should also be required to more effectively evaluate, implement and incorporate tools and measures to integrate renewable QFs into the grid.

3. The Utilities should take steps to manage solar generation on the grid through means other than simply curtailing QF power or slowing the continued growth of solar in the Utilities' BAs.

[28] Public Staff Witness Metz cited to 18 C.F.R. § 292.307(b)(1), stating that a utility may discontinue purchases during system emergencies "if such purchases would contribute to such emergenc[ies]." Tr. Vol. VIII, p. 122, ln 6-8. However, 18 C.F.R. § 292.307(b), preceding 282.307(b)(1), states that "During any system emergency, an electric utility may discontinue…(1) purchases from a qualifying facility if such purchases would contribute to such emergency…." (emphasis added). The language in 292.307(b)(1) is qualified by the language "during any system emergency" which indicates that a QF may be curtailed if its operation would contribute to an existing emergency. The language does not permit a QF to be curtailed if its operation could contribute to a potential future system emergency.

[29] NCSEA Witness Johnson described take-or-pay contracts in his direct testimony: "A take-or-pay contract is a supply agreement between a customer and a supplier in which the price is set for a specified minimum quantity of a particular good or service and the price is payable irrespective of whether the good or service is taken by the customer. Take-or-pay contracts are commonly used in the [Power and Utility] industry and may involve the supply of gas, transmission capacity or electricity. These contracts can be long-term in nature and contain terms and conditions with varying degrees of complexity (e.g., fixed or stepped volumes; simple fixed, stepped or variable pricing."Tr. Vol. VII, p. 325.

In support of Duke Energy's request for QF curtailment rights in the standard offer, Duke Energy Witness John S. Holeman, III described a variety of grid operation and reliability issues related to a greater penetration of solar QFs on Duke Energy's grid. See Tr. Vol. II, p. 60-92. Duke Energy has proposed curtailment as the primary means of addressing the issues they have identified.[30] However, the evidence indicates that Duke Energy has overstated the current impact of solar on the grid as well as the amount of solar that is likely to come online. The evidence also reveals that Duke Energy has not—to date—evaluated and worked to implement additional tools and methodologies that would assist Duke Energy in addressing their concerns. Consistent with Duke Energy's frequent refrain throughout this proceeding of creating a "smarter, sustainable energy future," the Commission should require Duke Energy to incorporate additional tools for grid integration rather than proposing simply to curtail fuel-free sources of energy.

Duke Energy has also discussed "operationally excess energy." In direct testimony, Witness Holeman stated that already in 2017 there have been 19 days and 71 hours when the DEP BA had operationally excess energy "due to unscheduled and unconstrained solar QF injections." Tr. Vol. II, p. 80, ln 9-11. On cross-examination Witness Holeman admitted, however, that over-generation can occur even in the absence of solar generating capacity. Tr. Vol. II, p. 133, ln 18-22. On cross-examination, Witness Holeman also stated that during those hours, DEP did not curtail any of the solar generation facilities that it owns, Tr. Vol. II, p. 138, ln 18-21, and that during these periods of operationally-excess energy, DEP did not curtail any of its non-solar QFs. Tr.

[30] Despite the fact that Duke Energy's qualms with solar QFs focus almost exclusively on DEP territory, its proposal includes curtailment in both the DEP and DEC balancing authority. See, e.g., Tr. Vol. II, p. 69, ln 1-2 (describing "operational excess energy currently occurring on the DEP system"); Id., Figure 2 (projected DEP BA load); Id., ln 3-4 ("the DEP BA is continuing to experience rapid growth of unplanned solar QFs"); Id., ln 14.

Vol. II, p. 139, ln 15-24. In direct testimony, Public Staff Witness Metz stated that Duke Energy has only curtailed QFs during certain <u>nighttime</u> hours, indicating that any QF curtailments have not been solar QFs. Tr. Vol. VIII, p. 121, ln 12-13; p. 122, ln 1-2.

Duke Energy has also stated that as of January 1, 2017 approximately 4,900 MW of solar projects are either under construction or in development. Tr. Vol. II, p. 322, ln 4-8. At the hearing, however, Duke Energy admitted that it was "highly unlikely" that all of the 4,900 MW of QFs in the interconnection queue would eventually be built. Tr. Vol. III, p. 12, ln 9-13. Duke Energy has overstated the amount of solar generation that will come online in order to justify their proposals that will stifle future QF development in North Carolina.

Duke Energy has further failed to adequately plan for greater solar penetration on the grid. Duke Energy repeatedly states that it supports a "smarter, sustainable renewable energy future" for North Carolina, but the evidence at the hearing indicated that Duke Energy has not adequately begun to incorporate best practices that would facilitate more effective integration of solar resources onto the grid. Despite what one might think from reading their testimony, Duke Energy was not caught off guard by increased solar generation on the grid. Witness Holeman testified that in 2014 Duke Energy was beginning the "solar build out" and were observing the experiences of utilities and grid operators in parts of the country with more solar. Tr. Vol. II, p. 164, ln 8-11. Responding to a question by Commissioner Brown-Bland, Witness Holeman also stated that "we anticipated it," referring to significant increases in solar (Tr. Vol. II, p. 165, ln 7) and admitted that as far back as 2010 Duke Energy had the ability to anticipate many of these challenges. Tr. Vol. II, p. 168, ln 24; p. 169, ln 1-14.

Duke Energy also commissioned at least two studies since 2014 from the Pacific Northwest National Laboratory (PNNL) concerning solar integration onto the grid.[31] The publicly released report from 2014 recommended that Duke consider developing greater fleet flexibility; improving solar injection forecasting capabilities; and incorporating demand response and battery storage. Tr. Vol. III, p. 126, ln 14-19; see also Confidential SACE Duke Panel Cross-Examination Ex. 5, p. 8 (2014 study at xi). Despite the existence of multiple studies from the DOE specifically addressing solar integration issues in Duke Energy service territory, Witness Holeman testified at the evidentiary hearing that he was not familiar with the substantive contents of these PNNL reports. Tr. Vol. II, p. 146, ln 20-21. Duke Energy did not share the results of a U.S. DOE National Laboratory with its Vice President of the System Planning and Operations Department, and Duke Energy has not demonstrated that they have taken the steps recommended in those reports.

Witness Holeman testified at the hearing that Duke Energy should be evaluating tools and methodologies to better integrate solar into the grid. Tr. Vol. II, p.172, ln 7-24; p. 173, ln 1-3. He said that other states are making progress on this front, and North Carolina should look to those states for their experience. Tr. Vol. II, p. 179, ln 14-21. Again, however, while Duke Energy may have identified a path forward, it should have been working on these methodologies since at least the last avoided cost proceeding. Instead, it now acts as though it has been caught flat-footed and has proposed only a blunt tool: curtailment. Duke Energy has stated that it is developing curtailment guidelines or procedures, but at the time of the evidentiary hearing it had not presented them to the

[31] Pacific Northwest National Laboratory is one of the United States Department of Energy national laboratories, managed by the Department of Energy's Office of Science.

Commission. Tr. Vol. II, p. 144, ln 13-15. The Commission should not allow the Utilities to use the avoided cost proceeding as a forum to address its inadequate solar integration planning. Instead, the Commission should require to Utilities to take a more active approach to integrating a higher penetration of solar and other QF resources onto the grid towards the next, and future, Commission proceedings.

V. CONCLUSION

Substantial and competent evidence in the record shows that the Utilities' proposals are contrary to PURPA, disregard the Commission's prior orders in avoided cost proceedings, and would discourage the development of QFs in North Carolina. The Utilities have premised their proposals on overstated impacts of solar QFs on the grid and inflated and one-sided claims of ratepayer impacts. In light of this evidence, SACE respectfully requests that the Commission take several actions.

First, SACE requests that the Commission reject the Utilities' proposed rollbacks to standard offer contracts. More specifically, SACE requests that the Commission maintain the current standard offer contract eligibility threshold of 5 MW and contract duration of 15 years. SACE further requests that the Commission reject Duke Energy's proposal to update avoided energy rates in standard offer contracts every two years. Maintaining the current standard offer parameters would continue to support a successful PURPA market, particularly in light of the expectation that the recent decrease in natural gas prices will lower avoided cost rates in this proceeding.

Although the Utilities attempt to gloss over the negative impact of their proposals on QFs by emphasizing their experience with bilateral negotiations, the evidence has demonstrated that contract negotiations with the Utilities will likely be more difficult than in the past based on non-negotiable contract durations and other unfavorable terms and conditions. Furthermore, Duke Energy's proposal of a hypothetical competitive procurement process also fails to blunt the impact of the Utilities' proposed standard offer contract changes because Duke has provided inadequate detail about how, whether, and when such a competitive procurement process would take place.

Second, SACE requests that the Commission deny proposals by the Utilities to alter avoided cost calculations and parameters in ways that will negatively impact QFs. SACE requests that the Commission continue to require the Utilities to assign capacity value in each year of the planning horizon and peaker application, rather than allowing the Utilities to eliminate recognition of capacity value in certain years or altogether. The Utilities' proposals directly contradict the approved peaker method and fail to properly compensate QFs. Similarly, SACE requests that the tired proposal to reduce the PAF for QFs other than run-of-river hydro to 1.05 be rejected as it has been in multiple prior proceedings. SACE requests that the Commission find that a PAF of 1.2 continues to properly compensate QFs based on reasonable availability. SACE further requests that the Commission reject Duke Energy's proposal to shift its seasonal split to 80/20 winter/summer because the shift is based on a flawed report and is premature and inappropriate at this time. SACE requests that the Commission also reject Dominion's proposal to completely eliminate its 3% line loss adjustment. Dominion has admitted that it has the ability to more accurately calculate QF line losses, but it has not done so.

Finally, SACE requests that the Commission reject Duke Energy's attempts to expand its ability to curtail QF power and to impermissibly amend the Commission's LEO standards, both of which directly contradict PURPA and the FERC's regulations and orders implementing PURPA. The Utilities should be required to take a more proactive approach to integrating renewable energy resources onto the grid rather than using PURPA implementation to stifle QF development.

PURPA is meant to encourage the development of renewable resources from independent power producers. The Commission has furthered this goal through its implementation of PURPA over many decades, and in spite of repeated efforts by the Utilities to roll back key provisions of that implementation. SACE respectfully requests that the Commission continue its long tradition of successfully implementing PURPA and encouraging QF development in North Carolina.

Respectfully submitted this the 22nd day of June, 2017.

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CERTIFICATE OF SERVICE

I certify that the persons on the service list have been served with the foregoing Post-Hearing Brief of Southern Alliance for Clean Energy either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 22nd day of June, 2017.

s/ Lauren Bowen
Lauren Bowen