

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION  
DOCKET NO. E-100, SUB 158**

<b>In the Matter of:</b> ) <b>Biennial Determination of Avoided Cost</b> ) <b>Rates for Electric Utility Purchases from</b> ) <b>Qualifying Facilities – 2018</b> ) ) ) ) ) ) ) ) )	<b>POST-HEARING BRIEF OF THE NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE AND THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION</b>
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**NCCEBA AND NCSEA’S POST-HEARING BRIEF**

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### **BACKGROUND**

Pursuant to the scheduling deadline set forth by Chair Mitchell of the North Carolina Utilities Commission (“Commission”) at the conclusion of the evidentiary hearing on July 19, 2019, the North Carolina Clean Energy Business Alliance (“NCCEBA”) and the North Carolina Sustainable Energy Association (“NCSEA”) jointly submit this post-hearing brief.

## I. INTRODUCTION

As the Commission is aware, House Bill 589, S.L. 2017-192 (“H.B. 589”) established a new renewable energy procurement regime in North Carolina. Moving away from the 5 MW standard offer Public Utility Regulatory Policies Act of 1978 (“PURPA”) model that led the state to become a national leader in clean energy development, the North Carolina General Assembly adopted a statutory framework that established two primary means through which North Carolina would procure new renewable energy generation resources and comply with its mandatory federal PURPA requirements: the Competitive Procurement of Renewable Energy (“CPRE”) program and the Green Source Advantage (“GSA”) program, together accounting for 3,260 MW of solar. These programs directly incorporate Duke’s administratively determined avoided cost rate, and as the Commission has acknowledged, these programs cannot be considered in a silo outside of the avoided cost proceeding.<sup>1</sup> While this avoided cost proceeding continues to establish the administratively determined avoided cost rate and the Schedule PP PPA and terms and conditions for QFs up to 1 MW, the significance of this proceeding is largely related to the avoided cost rate and any contract terms and conditions that will apply to the HB 589 programs.

This proceeding will also likely have an effect on the implementation of the North Carolina Clean Energy Plan currently under development as part of Governor Cooper’s Executive Order 80. The draft Clean Energy Plan, released on August 16, 2019, is intended to “foster[] and encourage the utilization of clean energy resources, including energy

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<sup>1</sup> Tr. Vol. 3, p. 142 (“[The Commission must] deal with the fact, in this proceeding, that the rate we set in this proceeding is going to have operative effect in some non-PURPA programs of the State of North Carolina. I have to deal with that. I cannot be in a silo and not deal with it.”).

efficiency, solar, wind, energy storage, and other innovative technologies in the public and private sectors, and the integration of those resources to facilitate the development of a modern and resilient electric grid.”<sup>2</sup> Although the Clean Energy Plan is still being finalized, it is representative of the State’s interest in the encouragement of clean energy resources and in the development of a modern electric system in North Carolina.

As described below, NCSEA and NCCEBA have raised a variety of concerns with the avoided cost rates, rate designs, contract terms and conditions, and charges that have been proposed by Duke and Dominion in this proceeding. NCSEA and NCCEBA request that the Commission adopt the recommendations put forth by NCSEA and NCCEBA in this proceeding as provided herein.

## **II. PROCEDURAL BACKGROUND**

### **A. COMMISSION ORDERS AND PRIOR AVOIDED COST PROCEEDING ISSUE HOLDOVER**

On June 26, 2018, in the above-captioned docket, the Commission issued its *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* (“*Order Establishing Biennial Proceeding*”), subsequently amended by orders dated January 4, 2019, January 25, 2019, and February 8, 2019, pursuant to the provisions of Section 210 of PURPA and the regulations of the Federal Energy Regulatory Commission (“FERC”), initiating the 2018 biennial proceeding to set avoided cost rates. The Order made Duke Energy Carolinas, LLC (“DEC”), Duke Energy Progress, LLC (“DEP”) (DEC and DEP, collectively, “Duke”), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (“Dominion,” “DNCP,” or “DENC”) (DEC, DEP, and DENC,

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<sup>2</sup> Executive Order 80, p. 4.

collectively, the “Utilities”), Western Carolina University (“WCU”), and Appalachian State University, d/b/a, New River Light and Power Company (“New River”) parties to the proceedings.

In its *Order Establishing Biennial Proceeding*, the Commission pointed out that in its October 11, 2017 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* issued in Docket No. E-100, Sub 148 (the “*Sub 148 Order*”) it had ordered DEC, DEP, and Dominion to address:

- (1) A continued evaluation of capacity benefits of qualified facility (“QF”) generation;
- (2) whether the utilization of a 2.0 Performance Adjustment Factor (“PAF”) as approved in the Stipulation of Settlement Among Duke Energy Carolinas, Duke Energy Progress, and NC Hydro Group (“Hydro Stipulation”) should continue as provided in that agreement;
- (3) the effect of distributed generation on power flows on each utility’s distribution system and the extent of power backflows at substations;
- (4) hourly combustion turbine (“CT”) operational data and marginal cost data on a season-specific basis; and
- (5) consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable.<sup>3</sup>

With respect to a rate design considering the characteristics of power supplied by a QF, the Commission in the *Order Establishing Biennial Proceeding* stated that it expected “DEC, DEP, and Dominion to file [in their 2018 Avoided Cost initial statements] proposed rate schedules that reflect each utility’s highest production cost hours, as well as summer and non-summer periods, with more granularity than the current Option A and Option B

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<sup>3</sup> *Order Establishing Biennial Proceeding*, p. 1.

rate schedules.”<sup>4</sup> The Commission also stated in the *Order Establishing Biennial Proceeding* that it will:

attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits and schedules, rather than a full evidentiary hearing for the purpose of receiving expert testimony.<sup>5</sup>

B. DUKE’S MOTION AND THE EVIDENTIARY HEARING

On November 1, 2018, Duke filed the *Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC* (“*Duke Initial Statement*”). In this filing Duke stated that, in addition to the typical avoided cost proposals required by PURPA, Duke was proposing an “updated Schedule PP avoided energy and capacity rate design” and an “integration services charge for intermittent solar QFs[.]”<sup>6</sup> Duke further stated that these new issues required an evidentiary hearing and requested the Commission order an evidentiary hearing on that basis.<sup>7</sup>

The North Carolina – Public Staff (“Public Staff”) filed the *Public Staff Motion for Extension and Modified Procedural Schedule* (“*Public Staff Procedural Motion*”) regarding Duke’s request for an evidentiary hearing on December 31, 2018. Then, on January 4, 2019, NCSEA filed its *Response to Public Staff’s Motion for Extension and Revised Procedural Schedule and NCSEA’s Motion for Modified Procedural Order on*

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<sup>4</sup> *Id.*, pp. 1-2.

<sup>5</sup> *Id.*, p. 1.

<sup>6</sup> *Duke Initial Statement*, p. 2.

<sup>7</sup> *Id.*



*Testimony* (“NCSEA’s Response and Motion”), to which Duke then filed *Duke Energy Progress, LLC and Duke Energy Carolinas, LLC’s Joint Response to NCSEA’s Response* on January 10, 2019.

The Commission revisited and restated its position on the procedural issues in its January 25, 2019 *Order on Procedural Schedule and Requiring Report* (“January 25th Order”), wherein Chairman Finley indicated that he would extend the deadline for the filing of reply comments and, also, suspend the deadline for the filing of proposed orders pending the determination by the Commission as to whether an expert hearing should be scheduled in this proceeding and the scope of issues to be heard at any such expert hearing.<sup>8</sup> Further, the Commission required Duke to confer with all the parties in the proceeding on or before March 8, 2019 and provide a report to the Commission summarizing the subjects at issue in this proceeding including, specifically, which issues are still in controversy and have sufficient merit to be considered at an evidentiary hearing.<sup>9</sup>

On February 8, 2019, NC WARN, Inc. (“NC WARN”) filed its Initial Comments. On February 12, 2019, NC Small Hydro Group, Cube Yadkin Generation LLC (“Cube Yadkin”), NCSEA, the Southern Alliance for Clean Energy (“SACE”) filed their initial comments, respectively. On February 13, 2019, the Public Staff filed its Initial Comments (“Public Staff Initial Comments”) along with a *Motion to Deem Its Initial Comments as Timely Filed*. On March 7, 2019, Dominion filed its *Revised Proposed Standard Offer*

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<sup>8</sup> *January 25th Order*, p. 4.

<sup>9</sup> *Id.*

*Avoided Cost Rate Schedules*<sup>10</sup> and, on March 14, 2019, Dominion filed a corrected *Revised Standard Offer Avoided Cost Rate Schedules*.

On March 27, 2019, the Public Staff, Dominion, NC Small Hydro Group, Duke, SACE, and NCSEA each filed reply comments, and, on April 10, 2019, Duke submitted the *Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Procedural Report Regarding Parties' Positions on Substantive Issues* (“*Procedural Report*”) pursuant to the *January 25 Order*. Therein, Duke outlined 30 deemed “substantive issues” for the parties to provide procedural recommendations on. Namely, the parties to the docket were instructed to rate the issues (1), (2), or (3) on a scale, with (3) being issues most in controversy and needing consideration at an evidentiary hearing and with (1) being issues with the least controversy or need least consideration at an evidentiary hearing.

On April 18, 2019, Duke and the Public Staff entered into the *Stipulation of Partial Settlement Among Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and the Public Staff* (“*Rate Design Stipulation*”), which stipulated an agreement between the Public Staff and Duke on avoided energy and avoided capacity rate design, including energy design methodology, hourly energy allocation, capacity design methodology, capacity seasonal allocation, and capacity hours.<sup>11</sup>

Based upon the *Procedural Report*, the Commission issued the *Order Scheduling Evidentiary Hearing and Establishing Procedural Schedule* on April 24, 2019 (“*Order Scheduling Evidentiary Hearing*”). The *Order Scheduling Evidentiary Hearing* set out a

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<sup>10</sup> Per the filing, this revised avoided cost proposal was “intended to show that these tariffs supersede both the Company’s proposed revised Schedule 19-FP and Schedule 19-LMP filed in Docket No. E-100, Sub 158 and the revised Schedule 19-FP and Schedule 19-LMP filed today in Docket No. E-100, Sub 148 to update the metering charges applicable to those tariffs in that docket” and was further made in conjunction with the *Order Approving Proposal and Requiring Filing of Revised Tariffs* in Docket No. E-22, Sub 560.

<sup>11</sup> *Rate Design Stipulation*, pp. 4-6.

timeline for the utilities to provide direct testimony and exhibits, the other parties to the docket to then provide their direct and exhibits testimony, and then the utilities to provide their rebuttal testimony and exhibits.<sup>12</sup> The order also scheduled the evidentiary hearing.<sup>13</sup>

On May 21, 2019, Dominion filed the direct testimony of Bruce E. Petrie (“Petrie Direct”), and Duke filed the testimony and exhibits of Glen A. Snyder (“Snyder Direct”), Steven B. Wheeler (“Wheeler Direct”), David B. Johnson (“Duke Johnson Direct”), and Nick Wintermantel (“Wintermantel Direct”).

Also, on May 21, 2019, Duke and the Public Staff entered into the *Stipulation of Partial Settlement Regarding Solar Integration Services Charge* (“*Solar Integration Charge Stipulation*”), which stipulated to an agreement between Duke and the Public Staff on Duke’s proposed Solar Integration Charge and its related components.<sup>14</sup>

On June 14, 2019, the Commission issued the *Order Requiring Supplemental Testimony and Allowing Responsive Testimony* (“*June 14th Order*”). In that order, the Commission requested that, given the contemporaneous order issued by the Commission in Docket No. E-100, Sub 101 regarding similar subject matter to an issue in the avoided cost docket – namely, what constitutes a “material modification” when adding energy storage to an online solar generator,<sup>15</sup> the parties in the avoided cost docket should address what avoided cost rate schedule and contract terms and conditions apply when a QF adds battery storage to an electric generating facility.<sup>16</sup>

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<sup>12</sup> *Order Scheduling Evidentiary Hearing*, p. 6.

<sup>13</sup> *Id.*

<sup>14</sup> *See, Solar Integration Charge Stipulation*, pp. 4-10. Duke’s Solar Integration Services Charge, as stipulated to with the Public Staff, is known throughout this proceeding as “Solar Integration Charge”, “Integration Charge”, “SISC”, “SSIC”, among other names. NCSEA and NCCEBA will hazard to utilize “SISC” as its term of choice for the underlying charge.

<sup>15</sup> *June 14th Order*, p. 1

<sup>16</sup> *Id.*

On June 21, 2019, NCSEA filed the Direct Testimony of Dr. Ben Johnson on behalf of North Carolina Sustainable Energy Association (“NCSEA Johnson Direct”), the Direct Testimony and Exhibit of R. Thomas Beach on behalf of North Carolina Sustainable Energy Association (“Beach Direct”), and the Direct Testimony Carson Harkrader on behalf of North Carolina Sustainable Energy Association (“Harkrader Direct”);<sup>17</sup> the Public Staff filed the direct testimony of Jeff Thomas (“Thomas Direct”) and the direct testimony of John R. Hinton (“Hinton Direct”); and, SACE filed the Direct Testimony and Exhibits of Brendan Kirby, P.E. on behalf of Southern Alliance for Clean Energy (“Kirby Direct”) and the Direct Testimony and Exhibits of James Wilson on behalf of Southern Alliance for Clean Energy (“Wilson Direct”).

On June 25, 2019, Dominion filed the Supplemental Testimony of James M. Billingsley on behalf of Dominion Energy North Carolina (“Billingsley Supplemental”) and Duke filed the Supplemental Testimony of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (“Snider Supplemental”).

On July 3, 2019: SACE filed the Responsive Testimony of Devi Glick on behalf of Southern Alliance for Clean Energy (“Glick Response”); Duke filed the Rebuttal Testimony of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (“Snider Rebuttal”), the Rebuttal Testimony of Steven B. Wheeler on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (“Wheeler Rebuttal”), and the Rebuttal Testimony of David B. Johnson on behalf of Duke Energy Carolinas, LLC

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<sup>17</sup> It was later discovered that NCSEA Witness Harkrader was not available to appear for the evidentiary hearing. To that end, on July 11, 2019 NCSEA filed *NCSEA’s Motion for Witness to be Excused from Appearance at Evidentiary Hearing*, which was opposed by Duke. On July 19, 2019, following oral arguments on the matter, the Commission denied NCSEA’s motion. As set forth herein, NCSEA’s requests the Commission allow NCSEA to withdraw the Harkrader Direct and NCSEA intends to refile as a consumer statement of position.

and Duke Energy Progress, LLC (“Duke Johnson Rebuttal”); Dominion filed the Rebuttal Testimony of Bruce E. Petrie on behalf of Dominion Energy North Carolina (“Petrie Rebuttal”); the Public Staff filed the Supplemental Testimony of Dustin R. Metz (“Metz Supplemental”); NCSEA filed the Responsive Testimony of Tyler Norris on Behalf of North Carolina Sustainable Energy Association (“Norris Response”); and, on July 5, 2019, Ecoplexus Inc. (“Ecoplexus”) filed the Supplemental Testimony of Michael R. Wallace, PE, CEM, GBE on behalf of Ecoplexus Inc. (“Wallace Supplemental”).<sup>18</sup>

On July 11, 2019, Dominion filed the Supplemental Rebuttal Testimony on behalf of James M. Billingsley on behalf of Dominion Energy North Carolina (“Billingsley Supplemental Rebuttal”) and Duke filed the Joint Supplemental Rebuttal Testimony of Glen A. Snider, Steven B. Wheeler, and David B. Johnson on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (“Duke Joint Supplemental Rebuttal”). On July 15, 2019, the evidentiary hearing began, and it concluded on July 19, 2019. On August 2, 2019, Duke filed Revised Late Filed Exhibit 1,<sup>19</sup> Late Filed Exhibit 2, Confidential Late Filed Exhibit 3, and Confidential Late Filed Exhibit 4. On August 14, 2019, Duke refiled Late Filed Exhibits 3 and 4 publicly, removing the confidentiality Duke originally assigned to them.

## ARGUMENT

### I. THE SOLAR INTEGRATION CHARGE AND THE RE-DISPATCH CHARGE BACKGROUND

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<sup>18</sup> Ecoplexus filed the Wallace Supplemental out of time per the *June 14th Order*. To amend this issue, Ecoplexus filed on July 5, 2019 the *Motion to Accept Michael R. Wallace’s Supplemental Testimony as Timely Filed*, which was not challenged.

<sup>19</sup> This exhibit was revised from a version that Duke presented near the conclusion of the evidentiary hearing.

In this proceeding Duke and Dominion have both proposed charges that they assert represent the costs they incur to integrate intermittent renewable energy generation onto their respective electric systems. Duke proposes a Solar Integration Charge which is based on the results of a 2018 study completed by Astrapé Consulting (“Astrapé”) entitled *Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study* (the “Astrapé Study”). Dominion proposes a Re-Dispatch Charge which it developed as part of its 2018 Integrated Resource Plan (“IRP”) and which was intended to quantify the utility’s “re-dispatch” cost of operating its existing grid with additional renewable energy resources.

As discussed below, the integration charges proposed in this proceeding are legally deficient, have failed to consider both the benefits of solar and available tools to recognize and incorporate those benefits, have not been adequately supported, include serious methodological flaws, and were developed solely by or on behalf of the utilities rather than through broader stakeholder engagement or the use of a third-party review committee. For these reasons, the utilities have failed to carry their burden of proof to support the proposed integration charges, and the Commission should reject them.

A. THE SOLAR INTEGRATION CHARGE AND THE RE-DISPATCH CHARGE ARE BARRED AS A MATTER OF LAW

The Solar Integration Charge and the Re-Dispatch Charge, as proposed by the Utilities and supported by the Public Staff, fail to comply with state and federal law and therefore must be rejected. The charges constitute single-issue ratemaking, contrary to North Carolina law, and as proposed, the charges fail to comply with PURPA and the Federal Energy Regulatory Commission’s (“FERC”) implementing regulations.

1. THE SOLAR INTEGRATION CHARGE AND THE RE-DISPATCH CHARGE CONSTITUTE SINGLE-ISSUE RATEMAKING AND ARE NOT PROPERLY PROPOSED DURING THE BIENNIAL AVOIDED COST PROCEEDING

North Carolina law and PURPA bar both Duke's proposed Solar Integration Charge and Dominion's proposed Re-Dispatch Charge as they have been proposed during this proceeding. The state and federal statutes mandating avoided cost requirements only contemplate payments made to the small power producers, not separate charges to those producers, and any such charge is barred in this proceeding as single-issue ratemaking under North Carolina law. To the extent that the utilities or the Public Staff allege the charges are decrements to the avoided cost rate, such a decrement is inconsistent with federal law and with the practical application of such a charge in the CPRE program, as more fully described below.

i. The Proposed Charges Do Not Comply With North Carolina Law

Duke's request to implement the solar integration charge and Dominion's similar request to implement the re-dispatch charge constitute single-issue ratemaking and are not supported by North Carolina law. In North Carolina, rates are to be set by the Commission pursuant to the requirements of N.C. Gen. Stat. § 62-133. N.C. Gen. Stat. § 62-3(24) defines "rate" to mean "every compensation, charge, fare, tariff, schedule, toll, rental and classification, or any of them, demanded, observed, charged or collected by any public utility, for any service product or commodity offered by it to the public, and any rules, regulations, practices or contracts affecting any such compensation, charge, fare, tariff, schedule, toll, rental or classification." It is uncontroverted that DEC, DEP, and Dominion are public utilities pursuant to N.C. Gen. Stat. § 62-3(23). The solar integration and re-

dispatch charges are a compensation or charge, to be demanded, charged, or collected, for a service product, in this case a charge for claimed ancillary services costs or alleged increased costs associated with ramping the fleet up or down. Duke Witness Glen A. Snider (“Duke Witness Snider”) even characterized the result of the Astrapé Study as pointing towards “a solar-specific energy rate” which led them to implement the Solar Integration Charge.<sup>20</sup> Therefore, the Solar Integration Charge and the Re-Dispatch Charge are rates pursuant to N.C. Gen. Stat. § 62-3(24).

Under North Carolina law, there are explicit limits on the Commission’s authority to revise the rates of a public utility: (1) a general rate case pursuant to G.S. § 62-133; (2) a proceeding pursuant to a specific, limited statute, such as G.S. § 62-133.2; (3) a complaint proceeding pursuant to G.S. § 62-136(a); or (4) a rulemaking proceeding.<sup>21</sup> The avoided cost proceeding does not constitute a general rate case, a complaint proceeding pursuant to G.S. § 62-136(a), or a rulemaking proceeding. Furthermore, while the avoided cost mechanism is statutorily enabled by PURPA, FERC regulations implementing those provisions, and G.S. § 62-156, nothing in the statutory avoided cost mechanism contemplates the additional charge (or general avoided cost decrement as discussed more fully herein) assessed by Duke and Dominion in their respective Solar Integration Charge and Re-Dispatch Charge.

Duke contends that G.S. § 62-156(b)(2) permits the imposition of the proposed integration charge. Namely, Duke believes this provision allows them to assess costs that

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<sup>20</sup> Tr. Vol. 4, p. 11. Duke Witness Snider did indicate that while Duke considered a solar-specific rate it ultimately “stuck with the historic precedent that we’ve used before in applying the peaker method of using that base load resource and then simply allocating it to the hours.” *Id.* at 11-12. It is unclear whether Duke Witness Snider considers the Solar Integration Charge a decrement to the avoided cost rate here, though he does seem to suggest it would be included in that calculation.

<sup>21</sup> See, *State ex. rel. Utilities Commission v. Nantahala Power and Light Company*, 326 N.C. 190, 195, (1990).



Duke alleges “will incur as a result of purchasing power from an intermittent solar QF versus from generating or purchasing the power from a firm load-following generating resource.”<sup>22</sup> G.S. § 62-156(b)(2) states as follows:

Avoided Cost of Energy to the Utility. - The rates paid by an electric public utility to a small power producer for energy shall not exceed, over the term of the purchase power contract, the incremental cost to the electric public utility of the electric energy which, but for the purchase from a small power producer, the utility would generate or purchase from another source. A determination of the avoided energy costs to the utility shall include a consideration of the following factors over the term of the power contracts: the expected costs of the additional or existing generating capacity which could be displaced, the expected cost of fuel and other operating expenses of electric energy production which a utility would otherwise incur in generating or purchasing power from another source, and the expected security of the supply of fuel for the utilities' alternative power sources.<sup>23</sup>

The statute does not allow for a utility to recover costs it claims arise from “growing levels of solar QFs that provide intermittent, non-dispatchable power” or “the impact on operating reserves, or generation ancillary service requirements, for new variable and non-dispatchable solar capacity” via G.S. § 62-156 rates.<sup>24</sup> While G.S. § 62-156 does reference “operating expenses,” it is only within the context of the operating expenses *avoided* by purchasing energy from a small power producer – i.e., those operating expenses avoided when the utility purchased power from a small power producer. G.S. § 62-156 does not allow for Duke or Dominion to independently impose costs allegedly tied to the small power producer onto that producer. Duke is not claiming to be avoiding the cost of intermittency, but rather claiming the cost they have calculated should be imposed either

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<sup>22</sup> *Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments*, p. 81, Docket No. E-100, Sub 158 (March 27, 2019) (“*Duke Reply Comments*”).

<sup>23</sup> Gen. Stat. § 62-156(b)(2).

<sup>24</sup> *Duke Initial Statement*, p. 31.

via charge or decrement to the underlying avoided cost calculation. This is simply outside the specific language and intent of G.S. § 62-156 and PURPA.

ii. The Integration Charges as Proposed Do Not Comply With PURPA

The integration charges, as proposed by the utilities and supported by the Public Staff, do not fit within the avoided cost framework as defined by PURPA and its implementing regulations. Conversely, even if the charges *were* considered part of the utilities' avoided cost, the integration charges as proposed would create variable rather than fixed avoided cost rates and would not comply with PURPA for that reason. As a result, under either scenario the charges are legally impermissible, and they should be rejected.

a. The Proposed Charges Do Not Fit Within the Avoided Cost Framework.

The Public Staff and Duke have divergent opinions on how to implement the Solar Integration Charge, and, as set forth below, neither position is permissible under PURPA. This divergence is likely the result of the precarious position such a charge/decrement presents – namely, a decrement from the general avoided cost rate would cause legal scrutiny under PURPA and FERC's implementing regulations and would be fraught with administrative and procedural uncertainty, while a completely separate line-item charge constitutes single-issue ratemaking that is disallowed in North Carolina.

The Public Staff takes the position that the integration charge is a separate component of avoided cost, *i.e.* according to the Public Staff, the updated avoided cost rate incorporating the Solar Integration Charge includes: (1) avoided energy; (2) avoided capacity; and (3) the Solar Integration Charge (and, presumably, the Re-Dispatch Charge). Specifically, the Public Staff took the position that the Solar Integration Charge should be

applied as a decrement to the avoided *cost* rate, and they were careful to differentiate the avoided cost rate from the avoided *energy* rate. This was made clear during the evidentiary hearing when Public Staff Witness Jeffrey Thomas stated:

Q [Smith] . . . Am I correctly characterizing your testimony yesterday, I think it was Mr. Thomas who said this, that it is -- that Public Staff's position that the solar integration charge is not a standalone line item charge, but rather a decrement or reduction to the avoided cost rate?

A [Thomas] Yes. That's the position that we've taken in our initial comments, that the SSIC is a component of the avoided cost, the decrement as allowed by PURPA, but should not be rolled into particularly like the avoided energy rate . . . I believe that this issue was resolved in Duke's reply comments where they kind of agreed that it should not be a decrement to the avoided energy rate, but rather would be a decrement to the avoided cost. And we had also expressed just some concerns about the SSIC collected from QFs would be flowed back to ratepayers via the fuel charge we had -- we had wanted to be a -- kind of a separate credit to fuel -- to ratepayers on the fuel rider instead of rolling it into the avoided energy charge.<sup>25</sup>

Such an interpretation does not withstand scrutiny. PURPA requires utilities to *only* purchase: (1) energy and (2) capacity from QFs. 18 C.F.R. § 292.303(a). This requirement to purchase energy and capacity provided by QFs is also identified in the section of PURPA's regulations that lists the factors that should be considered to establish avoided cost rates, 18 C.F.R. 292.304(e). Critically, this means that to be considered part of an avoided cost rate under PURPA and its implementing regulations, any integration charge deducted from the avoided cost rate would have to be calculated as part of either the avoided energy or the avoided capacity rate. However, the proposed integration charge is

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<sup>25</sup> Tr Vol. 7, pp. 33-35.

not calculated as part of the Peaker Methodology for establishing energy and capacity, which is the approved avoided cost methodology in North Carolina.

Additionally, the Public Staff has supported its position by arguing that including any integration charge as a third component of the avoided cost rather than a decrement to the avoided energy rate:

would ensure that the components of each utility's avoided costs are not distorted within the context of Renewable Energy and Energy Efficiency Portfolio Standard (REPS) cost recovery, fuel clause adjustment proceedings, demand-side management/energy efficiency programs pursuant to N.C. Gen. Stat. § 62-133.9 and HB 589 programs, all of which rely upon avoided cost as a benchmark.<sup>26</sup>

However, including an integration charge as a separate third component of the avoided cost does not comply with PURPA, and the alternative of including it as a decrement to the avoided energy rate is fraught with administrative and procedural hurdles that have not been adequately addressed in this proceeding. As a result, the Public Staff's proposal that the integration charge be considered a general third "component" of avoided cost is entirely inconsistent with the plain language of the regulations and should be rejected.

More particularly, the Solar Integration Charge and Re-Dispatch Charge are not "rates" pursuant to 18 C.F.R. 292.101(b)(5)<sup>27</sup> because they do not involve the sale or purchase of electric energy or capacity in the manner that they are being presented. Even if, for argument's sake, the solar integration and re-dispatch charges are rates pursuant to

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<sup>26</sup> *Public Staff Initial Comments*, p. 31.

<sup>27</sup> 18 C.F.R. 292.101(b)(5) states: "Rate means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity."

18 C.F.R. 292.101(b)(5), they are still inappropriate; 18 C.F.R. 292.304(e)<sup>28</sup> lists the factors that may affect rates in determining avoided costs, and ancillary services costs, as a separately modeled and calculated charge outside of the currently-employed “Peaker” methodology of determining avoided energy and capacity costs, are not listed among the factors that may be considered. Further, emphasizing the lack of agreement between Duke and the Public Staff, Duke maintains that the Solar Integration Charge is a stand-alone charge invoiced to the QF:

Q [Levitas] . . . The ancillary service charge that Duke is proposing is a discrete charge that would appear in the invoicing to the QF as opposed to a decrement to the avoided cost rate, correct?

A. [Snider] Yes.

As discussed above, Duke’s position that the Solar Integration Charge is a stand-alone rate represents single-issue ratemaking barred under state law. Even if Duke’s

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<sup>28</sup> “Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

- (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
- (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
  - (i) The ability of the utility to dispatch the qualifying facility;
  - (ii) The expected or demonstrated reliability of the qualifying facility;
  - (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
  - (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility’s facilities;
  - (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
  - (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility’s system; and
  - (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
- (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
- (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.”

position was that the charge is, in effect, a decrement to the avoided cost rate as presented by the Public Staff, it still must fail for the same reasons discussed above. Duke has not proposed its charge as a direct decrement to the avoided energy or avoided capacity rate, and the Solar Integration Charge is not formulated or proposed as part of the determination of Duke's avoided cost rates under the Peaker Method. Rather, the integration charge represents a stand-alone fee imposed on QFs.

Similarly, to the extent that the Dominion Re-Dispatch charge is presented as a separate line item rate or as a general decrement to avoided cost unrelated to the approved calculation of avoided energy and capacity, it must also fail. Thus, despite assertions to the contrary, the Solar Integration Charge and the Re-Dispatch Charge do not comply with PURPA. Duke has failed to adequately meet its legal burden, too, as it seeks to separately determine ancillary services costs from its underlying avoided energy and capacity calculations. In response to NCSEA's Initial Statement arguments on this legal issue, Duke claimed that "[r]ecognition of increased ancillary services costs not avoided by QFs is completely reasonable and appropriate under PURPA[.]" but Duke fails to provide any such instance where PURPA has interpreted a separately calculated integration charge arising out of ancillary services costs. Even in the Idaho example, examined more fully below, the Idaho Public Utilities Commission did not utilize PURPA analysis as the integration charge there was the result of a stipulation of the parties after meaningful stakeholder processes.<sup>29</sup>

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<sup>29</sup> *Duke Reply Comments*, pp. 76-78; *see, Kirby Cross Exhibit 2*; it should be noted that the "Idaho Study" as known herein refers to the Idaho Power Solar Integration Study Report. However, Kirby Cross Exhibit 1A is the Idaho Power Wind Integration Study Report, which similarly examined the effects of integrating renewable generation on the grid.

Duke and the Public Staff claim that the Solar Integration Charge is “consistent with the factors set forth in 18 C.F.R. 292.304(e).<sup>30</sup> NCSEA and NCCEBA do not dispute the plain language of 18 C.F.R. 292.304(e). 18 C.F.R. 292.304(e) allows the listed factors that may be considered “in determining avoided costs[.]” However, Duke does not specifically propose lower avoided capacity and energy rates for intermittent QFs, but rather to charge the intermittent QF for ancillary services provided by the utility. This clearly falls outside the statutory language at both the federal and state level and constitutes single-issue ratemaking as barred under North Carolina law. No matter whether the charge is a stand-alone line-item type charge made to the QF as proposed by Duke or it is a decrement to the amount paid to the QF as proposed by the Public Staff, the Solar Integration Charge, and the Re-Dispatch Charge for that matter, are not decrements to the avoided energy or capacity rate as contemplated under 18 C.F.R. 292.304(e). Thus, despite assertions to the contrary, the Solar Integration Charge and the Re-Dispatch Charge do not comply with PURPA.

b. The Use of Avoided Costs in Other Programs Illustrates Why Any Integration Charge Cannot Be Viewed as An Element of Avoided Costs.

1. CPRE

The potential application of the proposed Solar Integration Charge to CPRE illustrates why it has to be viewed as a stand-alone charge and not a component of avoided cost.<sup>31</sup> The role of avoided costs in CPRE is to establish a cap on the amount that can be

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<sup>30</sup> *Duke Reply Comments*, p. 76.

<sup>31</sup> As discussed below, NCSEA and NCCEBA oppose the application of any integration charge to CPRE for other reasons.

paid to successful bidders under the program. But the price successful bidders receive under the program is their bid price. In order for an integration charge to be collected from CPRE awardees it would have to be applied to reduce their revenues from what they would receive under their bid price, with the delta being applied to defray integration costs (This in turn means that a bidder would have to bid a price that is economically viable after deduction of the Solar Integration Charge, which presumably will be higher than what it would otherwise bid; that higher price would still have to be below the cap based on avoided costs to be eligible).

But if the Solar Integration Charge were in fact an element of avoided cost, it would operate to reduce the cap on allowable bid prices. While eligible bids would have to clear a lower bar than they would in the absence of an integration charge, there is no guarantee that the winning bids would actually be any lower than they would otherwise have been. Since both lowering the cap and deducting the Solar Integration Charge from awardee revenues would be inappropriate “double dipping.” there would be no source of revenue to apply to defray integration costs.

## 2. Rider Proceedings

Along with the H.B. 589 programs, North Carolina has enacted rider programs that have either, in practice, utilized the avoided cost rate as a means of calculating cost savings from demand-side management and energy efficiency programs, or have directly utilized avoided cost to enumerate costs associated with procurement of renewable energy.

N.C. Gen. Stat. § 133.8 is North Carolina’s renewable energy portfolio standard (“REPS”) statute. The North Carolina REPS statute utilizes the avoided cost as a means to capture cost recovery. Namely, the utilities are allowed certain cost recovery, through the



fuel rider, for amounts below avoided cost and through the REPS rider for any amounts expended beyond the avoided cost amount, as set forth in this biennial proceeding, to utilize renewable energy generation.

Duke and the Public Staff have taken the position that the Solar Integration Charge is an element of the avoided costs. When presented with the question about how to incorporate the Solar Integration Charge into REPS, the Public Staff Witness Thomas said it would be a meaningless shift of expenses since such issues are already paid through the fuel charge:

So I think it would be a meaningless shift. And since Duke has also stated that the -- any money collected by the SISC would be flowed back through fuel, it would appropriate, I think, to exclude the SISC from the avoided cost in REPS and then just keep that all in fuel to be flowed back at a time when it's eventually collected from all solar QFs.<sup>32</sup>

While Public Staff Witness Thomas's position here – that the charges from integrating solar are already baked into the fuel and REPS rider mechanism overlay – makes practical sense, it ignores the legal question of how the “avoided cost rate” can be defined elsewhere by statute as a singular rate brought by a well-defined PURPA-respective process at the Commission and then, suddenly, include a whole new element that is only appropriate to be used when logical. Unfortunately, the statutes which rely upon the definition of avoided cost do not work this way, and, legally, if the Solar Integration Charge or the Re-Dispatch Charge are intended to be intrinsic to the avoided cost rate, then that will trickle down, as defined by statute, to the rider programs.

Similarly, the Demand-Side Management and Energy Efficiency (“DSM/EE”) rider has traditionally relied upon the avoided cost amount as a means of quantifying cost

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<sup>32</sup> Tr. Vol. 7, p. 120.

savings through energy efficiency and demand-side management programs. While this is not as explicitly laid out in statute like the REPS mechanism, it has nonetheless been the practice to rely upon the avoided cost rate as a benchmark for utility costs. Should the proposed charges from Duke or Dominion be approved, then that practice will necessarily have to be altered as the prevailing avoided cost rate would not accurately reflect a metric consistent with energy saved via DSM/EE programs, but, instead, the avoided cost rate would be a Solar specific rate for QFs without ancillary services.

- c. Even If the Proposed Integration Charges Were Incorporated Into The Avoided Energy Rate, They Would Not Be A Fixed Rate as Required by PURPA

As this Commission is aware, PURPA requires utilities to offer fixed avoided cost rates that are determined at the time the QF enters into a legally enforceable obligation (“LEO”).<sup>33</sup> In the E-100 Sub 148 proceeding Duke proposed an avoided cost rate that would be updated every two years rather than fixed for the duration of the contract. Based on arguments from intervenors and the Public Staff, as well as from the Commission’s well-established precedent on this topic, the Commission found that Duke’s proposal to update avoided cost rates every two years within existing contracts did not comply with PURPA.<sup>34</sup>

Despite this clear requirement, the utilities have now proposed an integration charge that would be updated every two years – in other words, a variable rate. While NCSEA and NCCEBA maintain that the integration charges proposed in this proceeding

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<sup>33</sup> See, e.g. *Sub 148 Order*, pp. 68-69 (“The Commission notes that a QF’s legal right to long-term fixed rates under Section 210 of PURPA is addressed in FERC’s J.D. Wind Orders . . . [and] the Commission finds that Duke’s proposal to adjust avoided energy rates every two years should not be adopted in this case.”).

<sup>34</sup> *Id.*

should not be approved, for the reasons set forth both above and below, if the Commission were to otherwise determine that the integration charge should be incorporated into the avoided energy rate, this would result in an avoided cost rate that was variable rather than fixed, and therefore impermissible as a matter of federal law and as correctly applied by this Commission.

**II. THE ASTRAPÉ STUDY USED TO DEVELOP THE SOLAR INTEGRATION CHARGE IS DEFICIENT IN MULTIPLE RESPECTS AND SHOULD BE REJECTED**

The Astrapé Study is insufficient to carry Duke's burden of proof in this proceeding for a variety of reasons. First, Duke has failed to evaluate the potential benefits of solar in addition to any costs, as required by prior Commission orders. Second, the process used to develop the Astrapé Study is inadequate because the study's methodologies were not adequately vetted and did not go through a technical review committee or other similar review process common for studies of this type. Third, the Astrapé Study relied on methodologies and a broad range of assumptions that are fatally flawed. Finally, the proposed Stipulation between Duke and the Public Staff incorporated these flaws, adopted an arbitrary and unsupported cap, and failed to define key settlement terms. As a result, the Commission should reject the Astrapé Study, the proposed Solar Integration Charge, and the *Solar Integration Charge Stipulation*.

**A. THE ASTRAPÉ STUDY AND DUKE'S PROPOSAL DO NOT COMPLY WITH THE SUB 148 ORDER OR THE SUB 140 ORDER AND FAIL TO CONSIDER THE BENEFITS OF SOLAR**

The Utilities' proposals to impose integration charges fail to comply with the Commission's orders in prior avoided cost proceedings which required the Utilities to evaluate both the costs and benefits of solar generation. NCSEA and NCCEBA have

presented specific examples of quantifiable renewable energy benefits, as well as examples of tools that the Utilities or the Commission could assess and implement in North Carolina to more effectively integrate renewables onto the grid. Because the Utilities have failed to evaluate potential benefits of solar and opportunities to more effectively integrate renewable energy, the proposed integration charges should be rejected.

The Commission has previously directed the utilities to provide meaningful analysis to assess both costs and benefits to the electric system brought by QF generation and, specifically, solar QFs. In Docket No. E-100, Sub 148, the Commission stated in its findings of fact that the benefits of distributed generation need to be considered in future avoided capacity determinations:

6. It is appropriate for the utilities to continue to evaluate the capacity benefits of QF generation and to make other changes as needed to accurately reflect the avoided capacity benefits provided by QF generation of all resource types over the short and long run.<sup>35</sup>

In Docket No. E-100, Sub 140, the Commission specifically enumerated the need to determine the *benefits* of distributed solar before determining an integration cost:

The Commission finds that, while ultimately it may be appropriate for DEC, DEP and DNCP to include the costs and benefits related to solar integration in their avoided cost calculations, such inclusion will be appropriate only when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained. Accordingly, the Commission concludes that it is premature for DEC, DEP and DNCP 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.<sup>36</sup>

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<sup>35</sup> *Sub 148 Order*, p. 7.

<sup>36</sup> *Order Setting Avoided Cost Input Parameters*, p. 61, Docket No. E-100, Sub 140 (December 31, 2014) (“*Sub 140 Phase I Order*”).

Despite these clear directives, Duke and Dominion have failed to reflect the benefits from distributed generation in their avoided cost filings. In fact, when asked what efforts Duke made to identify benefits that are associated with renewable generation, Duke could not even identify benefits and only spoke of solar in terms of avoiding additional charges to be passed to the QF, rather than differentiating the benefits that distributed generation has as opposed to traditional, centrally located generation. Specifically:

Q. [Levitas] What efforts did you make to identify benefits that are associated with renewable generation?

A. [Snider] We have consistently looked for additional benefits. And, you know, I think some of the intervenors have brought up a couple: [avoided] T&D. What we're seeing on a one-off basis, one by one by one, is that there are probably additional costs. It's difficult to ascertain a rate. So it's one thing to say we believe, based on what we're seeing with the QF, that there are T&D costs being imposed that the QF is not paying for, it's another thing to do a study that's substantially supported the way our ancillary service study is to say here's the rate we should charge. So we're not charging the QF, because we don't have a study to say, oh, the QF is imposing T&D costs, such as the O&M of new facilities that's going to be absorbed by customers. It's hard to quantify that. So we haven't asked for that as a cost. The fact that the T&D that was available on the grid is now being consumed by the existing solar generators which makes placing further firm generation on the grid more expensive is Difficult to quantify. So we haven't included those costs. The areas that have been brought up as speculative benefits, we have seen example after example of costs. We have yet to define a study that says here is the exact cost it's imposing. So again, we feel that that's a, you know, conservative way to give deference to the QF community and not assign a cost unless we have a defined study that we feel we can quantify those costs. So we've looked hard at it, we just don't have a systemwide study to define those costs.

When pressed again on the question of whether Duke had studied the potential benefits, as required by the *Sub 140 Order* and the *Sub 148 Order*, of added solar to the grid, Duke Witness Snider was more specific:

Q. [Levitas] Well, I understand that's your opinion that you don't think that there are benefits or haven't identified benefits, but I guess your answer to my question is, you did not engage a third-party consultant and ask them to do a study of those benefits to see what they might determine; isn't that correct?

A. [Snider] We don't believe -- we're -- we'd have a hard time scoping the study, because we're trying to figure out what benefits -- just like the intervenors, I think, didn't hire any third parties that were able to put forward any credible study to say here's a benefit that is being missed. So I'm waiting to review a study that shows a benefit, a concrete avoided cost, but for benefit, that under PURPA, but for the purchase of that QF, there would have been additional benefits to the consuming and using public. If someone can point those out, we're happy to adopt them. And again, we really don't have a dog.<sup>37</sup>

Duke Witness Snider's response above shows that Duke did not incorporate the benefits of distributed solar in the Astrapé Study despite such benefits being required to be reviewed under the *Sub 140 Order* and the *Sub 148 Order*. Apparently, Duke's position is that if they closely evaluated distributed generation, which they have not yet done, there would not only be zero benefits to the grid but, instead, there would be further costs. In fact, Duke Witness Snider further stated, "so my testimony has been it's not that -- it's like you're not studying it to show us the benefits. Well, we don't know how to quantify benefits when what we're seeing is cost."<sup>38</sup> It seems clear from the Duke panel testimony and the filings made by Duke that they intend to obfuscate the benefits of solar. Of course, there are potential upgrade costs, depending on siting, for new generation added to the transmission and distribution systems – neither NCSEA, NCCEBA, or any other intervenor has denied this. But to argue that these upgrade costs negate any future benefits is facetious

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<sup>37</sup> Tr. Vol. 2, pp. 20-21.

<sup>38</sup> Tr. Vol. 4, p. 28.

– Duke Witness Snider himself articulates such upgrades as a “30-year asset”.<sup>39</sup> Recent price trends and market projections of generation resource costs indicate that renewable energy, particularly when paired with storage, will be more cost-effective than traditional fossil fueled generation sources.<sup>40</sup> By looking only to potential short-term upgrade costs rather than to the likely long-term benefits of renewables, Duke misses opportunities for significant cost savings in the future.

Regardless, Duke has failed to include in its filings the requisite breakdown of benefits to capacity as required by the recent *Sub 148 Order* and the broader requirements of *Sub 140 Order* regarding solar benefits. If there truly are no benefits to distributed solar (which would run counter to countless national and statewide studies), as Duke Witness Snider appears to be alleging, Duke has failed to substantiate this position with their model or with data and analysis presented to the Commission that incorporates benefits of solar as previously directed. NCSEA, NCCEBA, and the other intervenors should get the opportunity to evaluate Duke’s ascertainment of benefits in this proceeding – instead, Duke continues to hide the ball and instead proposes a new charge which does not comply with the Commission’s prior orders.

Similarly, Dominion’s Re-Dispatch charge evaluates only the purported costs caused by increased ramping of existing generation resources. The IRP process used to establish the proposed Re-Dispatch charge does not appear to incorporate any evaluation of potential benefits of renewables or opportunities to capture and quantify those benefits. As a result, the Re-Dispatch charge should also be rejected.

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<sup>39</sup> Tr. Vol. 4, p. 27.

Duke Witness Nick Wintermantel (“Duke Witness Wintermantel”), one of the architects of the Astrapé Study, in testifying that the Astrapé Study modeled the two Duke territories as islands (rather than as being connected to both each other and also other neighboring utilities with potential energy reserves to meet the needs of a variable Duke system), stated that the benefits of an interconnected system – where a neighboring utility could help to offset variability concerns via traded generation – were implicit to the study because the zero-solar model was compared against historical reserves. “Importantly, SERVM<sup>41</sup> implicitly recognizes the benefits of participating in an interconnected system by modeling reserves in the no-solar case that are comparable to historical reserves.”<sup>42</sup> However, Duke Witness Wintermantel later stated that the Astrapé Study and the SERVM Model only utilized 2015 operating reserves historical data when analyzing the system, and, in fact, the 2015 historical data was modeled as the “no-solar” scenario given that the interconnected distributed solar at that time was a much lower amount than at the present:

Q. [Smith] So essentially, backing up. I guess I'm asking did you compare it against past years of Duke's real world statistics? I mean, Duke theoretically gave you inputs to include in your model, so couldn't you have compared it against what you looked at in past years to see, okay, our outcome here matches historical analysis?

A. [Wintermantel] Yeah. That's exactly what we did when we looked at operating reserves. So we looked at operating reserves before solar was added. Little to no solar was added back in 2015. We compared those operating reserves to our modeling exercise to ensure that our no solar case in our model, the operating reserves were equivalent. And really what it does is it says that, in 2015, in the real world, we were reliable with this amount of operating reserves. That in our model, when we model the no-solar case, we should have reasonably the same amount of operating

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<sup>41</sup> “SERVM” is the trade name for Astrapé’s proprietary production cost model.

<sup>42</sup> Tr. Vol. 4, pp. 99-100.



reserves. So that comparison validates, kind of, the beginning step of the study.

Q. So you said 2015 you looked back on. Did you look at 2016? 2014? 2013? Any other years?

A. No, we looked at 2015.<sup>43</sup>

While NCSEA and NCCEBA will explore the insufficiency of the Astrapé Study and the model it relied upon more fully herein, it's important to note that Duke Witness Wintermantel stated that the Astrapé model *implicitly* included some benefits of distributed solar because it compared a zero-solar case against historical data, when that statement is inaccurate. The Astrapé Study did not model against sufficient historical data – it used 2015 data only – and it used such 2015 data as the “zero-solar” case, not to validate or otherwise show the benefits/costs of increasing solar generation. If such data was the basis for a “no-solar” case, then it would be impossible to say that it was also the basis for finding implicit benefits to distributed solar.

B. NCSEA, NCCEBA, AND OTHER INTERVENORS HAVE PROVIDED EXAMPLES OF BENEFITS OF SOLAR THAT SHOULD BE INCLUDED IN THIS ANALYSIS

As NCSEA Witness Beach pointed out – the Astrapé Study fails to quantify lower market prices due to the presence of solar on the grid (helping to reduce avoided energy and capacity rates) and avoided transmission and distribution capacity costs.<sup>44</sup> On the avoided transmission and distribution capacity costs issue, Duke takes the position that distributed solar generation gives Duke additional costs rather than benefits.<sup>45</sup>

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<sup>43</sup> Tr. Vol. 4, pp. 119-120.

<sup>44</sup> Tr. Vol. 5, p. 115.

<sup>45</sup> Tr. Vol. 3, pp. 18-22.

Q. [Levitas] Well, did you retain a third-party consultant and ask them whether they could develop a study for the purpose of determining those benefits?

A. [Snider] Actually, it was -- the benefits you're referring to we see as a cost. We have many examples on a project-by-project basis of where these are costs. So we're not avoiding T&D, we're incurring T&D costs. The other side in this proceeding is claiming those to be benefits. I have yet to, in talking to any of my peers around the country, find an industry or a utility that says the addition of a vast amount of intermittent renewable generation is helping us to have a smaller transmission and distribution budget. I have yet to come up with a single peer that has said that.<sup>46</sup>

In his report, NCSEA Witness Beach demonstrated that Duke has already quantified its avoided transmission and distribution costs, which are used to assess the benefits of energy efficiency programs.<sup>47</sup> Contrary to Duke Witness Snider's assertions, NCSEA Witness Beach was able to develop a mechanism to reflect avoided transmission and distribution costs allowed by distributed generation. NCSEA Witness Beach derived the peak capacity allocation factors ("PCAFs") to develop generally applicable avoided cost rates to those avoided transmission and distribution costs.<sup>48</sup> Using load and substation data, NCSEA Witness Beach developed a process to determine avoided transmission and distribution costs in a meaningful and precise way:

The process used to develop the avoided distribution rates in [Table 5 in NCSEA Witness Beach's report] suggests how one could develop time-varying, locational values for avoided distribution costs. The substation data shows that some distribution substations are closer to capacity than others, and small, distributed solar resources (as well as other types of DERs) installed on those constrained parts of the distribution system will provide greater benefits than in other locations. In other words, there is significant

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<sup>46</sup> Tr. Vol. 3, pp. 19-20.

<sup>47</sup> NCSEA Initial Comments, Attachment 2 ("*Beach Affidavit*"), pp. 21-22, Docket No. E-100, Sub 158 (February 12, 2019).

<sup>48</sup> *Id.* at 22.

variation in avoided distribution costs by location, and constrained parts of the distribution system will have avoided costs that are far higher than the system average.<sup>49</sup>

Duke takes the position that NCSEA Witness Beach's proposal is speculative because it is based upon "a generalized quantification of estimated 'time-varying locational values' of load reductions across DEC's and DEP's entire distribution systems."<sup>50</sup> However, NCSEA Witness Beach's "generalized quantification" is based upon the limited data provided by Duke to NCSEA Witness Beach, who was limited to 20 substations of load data.<sup>51</sup> Furthermore, Duke clearly has better access to information and load data on its system than any intervenor – NCSEA and Witness Beach are simply proposing a calculation to determine where avoided transmission and distribution costs can be articulated. This clearly occurred in California, which recently reported a \$2.6 billion avoided cost savings due to avoiding the need to build certain new transmission and distribution lines due to energy efficiency and distributed renewable energy resources.<sup>52</sup> Duke also objects to the underlying methodology in NCSEA Witness Beach's proposal because "consistent with Duke's practice in all prior avoided cost proceedings", Duke does not consider the impact of distribution and transmission upgrades in determining avoided cost. NCSEA and NCCEBA do not see the issue of including this in the future given the prior avoided cost orders which indicate that benefits of distributed generation must be accounted for, which should include avoided transmission and distribution costs. Moreover, to object to NCSEA's and NCCEBA's proposal as falling outside the statutory

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<sup>49</sup> *Id.* at 25.

<sup>50</sup> *Duke Reply Comments*, p. 127.

<sup>51</sup> See, *Beach Affidavit*, p. 22, fn. 30.

<sup>52</sup> [Board approves 2017-18 Transmission Plan, CRR rule changes](#), (March 2018)

authority and precedent of the avoided cost proceeding while also proposing the solar integration charge is logically inconsistent.

Finally, Duke objects to NCSEA Witness Beach's proposal on a technical level because it includes "broad assumptions" about the related transmission and distribution upgrades, system planning, and the use of QF resources, which, per Duke, are intermittent and unreliable.<sup>53</sup> Duke compares energy efficiency measures as incomparable to QF generation because of the difference in their predictive nature. Duke says its "planners must design individual T&D equipment for the highest loading scenarios and cannot rely on generalized assumptions of average generation or state-wide geographical diversity of many QFs."<sup>54</sup> Duke again fails to see the problem that NCSEA Witness Beach is solving for – he is not saying that energy efficiency and solar have the same variability, or that solar generation can always fulfill every load need that the Duke system will have. What NCSEA Witness Beach has done, unlike Duke, has provided a set of data points to show the benefits of distributed solar on the grid, notably in savings on transmission and distribution costs. Duke's position ignores real-world examples of opportunities to incorporate and quantify ancillary services such as batteries, smart inverters, or other technologies which can help to meet peak demand. As noted above, the burden from the prior to avoided cost orders is on the utilities to capture the benefits of distributed generation. NCSEA Witness Beach has done so and has used data provided by Duke. Duke, instead of incorporating such potential benefits into its Astrapé Study has instead contested them without challenging NCSEA Witness Beach's underlying findings or employing a counter study to show that NCSEA Witness Beach's proposal is wrong.

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<sup>53</sup> *Duke Reply Comments*, pp. 128-129.

<sup>54</sup> *Id.* at 129.

**III. THE ASTRAPÉ STUDY IS SYMPTOMATIC OF DUKE'S ONGOING FAILURE TO REPLY UPON AND PROVIDE, EVEN WHEN REQUIRED BY ORDER, MEANINGFUL DATA REFLECTING THE COSTS AND BENEFITS ASSOCIATED WITH DISTRIBUTED GENERATION AND SOLAR**

The Astrapé Study is premised upon a SERVM model that does not include any feedback or inputs from any other stakeholders.<sup>55</sup> As discussed above, the Astrapé Study failed to meet the requirements set forth in the *Sub 140 Order* and the *Sub 148 Order*, namely requiring that Duke study and include in its integration analysis both the costs and benefits of distributed solar generation. NCSEA, NCCEBA, and the other intervenors have pointed out many potential benefits of distributed solar generation, but Duke has, despite this information, refused to study or incorporate such benefits into their filings in this proceeding and instead takes the position these benefits simply do not exist without providing meaningful data to support that claim. This fits a pattern of Duke behavior of ignoring Commission requests for Duke to obtain and utilize solar data to provide the Commission, stakeholders, and the ratepaying public a true understanding of the costs and benefits of distributed solar.

One example of this related to net metered solar systems. Net metering has been an active issue in the North Carolina energy policy sphere since the late 1990s. The Commission issued the *Order Adopting Net Metering* on October 20, 2005, which adopted an expansion of the previously-limited net metering program and ordering that

Progress, Duke, and Dominion shall file on or before December 1 of each year, beginning December 1, 2006, in Docket No. E-100, Sub 83 an annual report indicating the numbers of net metering applicants and customer-generators, the aggregate capacity of net metered generation, the size and

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<sup>55</sup> While the Public Staff and Duke stipulated to the Solar Integration Charge, there is no evidence that the Public Staff changed the Astrapé Study or the underlying SERVM model.

types of renewable energy facilities, the amounts of on-peak and off-peak generation credited and ultimately granted to the utility, and the reasons for any rejections or removals of customer-generators from net metering;<sup>56</sup>

NCSEA and NCCEBA thoroughly examined the Commission net metering dockets and were unable to any filings from the Utilities meeting this requirement.

More recently, in the interconnection standards docket, the Commission directed Duke and Dominion to address the issue “regarding the future of the distribution grid, the costs of operating and maintaining that grid, the benefits provided by distributed generation on the grid, and how those costs and benefits are to be apportioned to grid users and recovered.”<sup>57</sup> Specifically, Public Staff Witness Jay B. Lucas pointed out that as distributed generation facilities on the grid continue to rise, there is a question as to who pays for the grid operation and maintenance of those new facilities. The Commission, recognizing Witness Lucas’s question, directed Duke and Dominion to:

address [the issue related to costs incurred from increased distributed generation on the grid] in testimony filed in their next general rate cases. The Commission especially requires testimony characterizing the benefits that distributed generators are receiving from the Utility’s Systems, estimating their share of the related costs, and providing options for fully recovering those costs from distributed generators. The testimony should also explain the impact that shifting these costs to distributed generators would have on other customer classes.<sup>58</sup>

NCSEA and NCCEBA dispute Public Staff Witness Lucas’s underlying assumptions regarding the costs of increasing distributed generation as set forth herein and in NCSEA’s and NCCEBA’s other filings made in this docket and elsewhere. However, Public Staff

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<sup>56</sup> *Order Adopting Net Metering*, Docket No. E-100, Sub 83, October 20, 2005.

<sup>57</sup> *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony*, pp. 62-63, Docket No. E-100, Sub 101 (June 14, 2019).

<sup>58</sup> *Id.* at 64.

Witness Lucas's earnest request for an examination of the costs incurred and incurring related to distributed generation is a valid question – and NCSEA and NCCEBA would welcome the opportunity to engage in a holistic discussion about the value of solar. Such an undertaking should include all of the costs and benefits of solar, and through meaningful dialogue between stakeholders resulting in a study in the vein of the Idaho Power Solar Study referenced in SACE Witness Kirby's testimony. However, like many other occasions where the utilities have been directed to engage in a data-driven discussion about distributed generation costs (this time in the framework of interconnection), Duke rebuffed.

Despite the request from the Public Staff and the directive from the Commission to file testimony *in its next general rate case* regarding the interconnection-related costs brought up by Public Staff Witness Lucas, Duke has sought waiver of such requirement.

In its *Motion for Waiver* filed on August 9, 2019, Duke stated:

2. As a part of its on-going avoided cost assessments to study the costs and benefits of distributed generation (“DG”), Duke has historically reviewed the issues raised in the Commission's directive in forums other than base rate adjustment proceedings. Since the issuance of the NCIP Order, Duke has engaged with a number of experts regarding a potential study and has commenced a review of pre-existing materials on the subject. The Companies' understanding of the impacts of DG on system costs is still evolving, but it is already apparent that assessing the costs and benefits of DG is a complex endeavor that requires a high degree of technical analysis and input from a wide spectrum of subject matter experts.

3. In light of this complexity, Duke believes that additional time is needed to conduct the required analysis. Furthermore, additional time would allow for a more collaborative process with the Public Staff to better understand its recommendation and with other stakeholders to obtain a broader perspective. However, in light of the currently contemplated timing of the next general rate cases for DEP and DEC this year, the Companies do not believe that such collaboration and analysis can be completed in sufficient time to support detailed and comprehensive technical testimony on the issue within those rate cases.

4. Therefore, through this Motion, the Companies seek additional time to facilitate such collaboration and further analysis of these issues. The Companies would commit to the following specific steps: (1) retain expert consultant by the end of third quarter 2019, (2) prepare study methodology and outline options for cost recovery by the end of first quarter 2020, (3) discuss study methodology and cost recovery options with the Public Staff and other stakeholders and receive feedback by the end of second quarter 2020, (4) 3 complete cost estimation and file study results with the Commission by the end of fourth quarter 2020, and (5) file testimony on the topic in the first rate case immediately following the completion of the interim steps unless an alternative forum is identified in the stakeholder engagement process.<sup>59</sup>

As stated in its *Response to Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Motion for Waiver*, NCSEA and NCCEBA applaud Duke's request for more time for collaboration and thorough research into the complex question of the costs on the system accruing from distributed generation. However, it is clear that Duke seeks to control the data presented to the Commission and separate what should be a holistic discussion. In his request, Public Staff Witness Lucas refers to the costs of "grid operation" as being part of the ongoing costs associated with increasing solar generation on the grid.<sup>60</sup> Moreover, the Commission's analysis of the problem discusses the alleged costs in the scope of operating and maintaining the grid. Surely, part of this equation includes the operating reserves that Duke relies upon in their Astrapé Study to show the allegedly ever-increasing costs associated with added distributed generation to the grid. The question is not whether the problem the Commission sought about from the utilities from in the Interconnection Order is different than the problem Duke seeks to solve with the Solar Integration Charge

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<sup>59</sup> *Motion for Waiver*, pp. 2-3, Docket No. E-100, Sub 101 (August 9, 2019).

<sup>60</sup> "With those additional [distributed generation] facilities comes additional grid operation and maintenance expenses." *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony*, p. 62, Docket No. E-100, Sub 101 (June 14, 2019).



(and, to Dominion's case, the Re-Dispatch Charge), but rather how much these two issues overlap.

Despite this seeming clear overlap, Duke does not mention in its *Motion for Waiver* that it hired Astrapé to conduct a study in 2017 related to the costs associated with operating reserves on the grid in the alleged face of solar generation variability. Duke does not mention that it spent considerable time and money preparing testimony in this docket that touches on the alleged costs of distributed solar. Instead, Duke seeks more time to unilaterally hire an expert consultant who will prepare yet another study, which will be subject to review and scrutiny of the stakeholders. NCSEA and NCCEBA predict a similar discussion in that case where the parties to the docket object to the proposed study due to issues that would be solved with transparency and stakeholder input and review.

As set forth herein, NCSEA and NCCEBA believe a better solution would be a study with meaningful stakeholder feedback and Commission oversight where costs and benefits of distributed generation, including solar in particular, are studied and meaningfully identified in a streamlined but holistic process.

It appears the Commission seeks to further the discussion in a more holistic process of examining generation sources being incorporated into the grid and planning for operating reserves. In the *Order Scheduling Technical Conference and Requiring Responses to Commission Questions* issued by the Commission in the most recent IRP docket, the Commission citing as an example that "Duke stated that it has not been able to identify the locational value of distributed generation sources", ordered a technical

conference to discuss integrated systems and operations planning.<sup>61</sup> The Commission stated specifically:

The Commission has carefully considered the importance of the evolving nature of integrated resource planning. The Commission recognizes that some of the most promising emerging resource solutions, such as battery storage and leading-edge intelligent grid controls, are still in the early stages and will require enhanced capabilities, such as those promoted through ISOP. As a result, the Commission concludes that it would be helpful for the Commission to receive additional information from Duke about ISOP. In addition, the Commission would find it helpful for DEC to file responses to the Commission Questions attached as Appendix A to this Order.<sup>62</sup>

It's clear that the Commission, as well as the Public Staff, wish to address issues related to distributed generation, including, in particular, efficiency in costs and holistic integrated resource planning. It is also clear that Duke does not understand the need for examination of the underlying distributed generation data as it has repeatedly failed to timely provide what has been requested of it. Further, it seems that Duke either has not identified or has otherwise not attempted to connect the silos involved here. As set forth above, there are at least four dockets where Duke has been requested or identified the same or a very similar (or interrelated) data set. There is simply no reason for there to be this much inefficiency and overlap between coordinated studies when, from conceptual point of view, they are all related to the planning and interconnection of distributed generation and the associated costs and benefits. Ultimately, these inefficiencies are bore out to the ratepayers – they will pay through their rates for the various studies, proposals, and potential or likely litigation in the underlying dockets. Much like the Commission has directed in the Integrated

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<sup>61</sup> *Order Scheduling Technical Conference and Requiring Responses to Commission Questions*, Docket No. E-100, Sub 157 (July 23, 2019).

<sup>62</sup> *Id.* at 1.

Resource Planning docket, there needs to be a broader planning action here to provide this Commission and North Carolina with the standard for the value of distributed generation, including solar, in this state.

**IV. THE ASTRAPÉ STUDY METHODOLOGY AND THE PROCESS USED TO DEVELOP IT ARE INADEQUATE, AND THE STUDY RESULTS SHOULD BE REJECTED**

**A. DUKE'S PROCESS OF DEVELOPING THE SOLAR INTEGRATION CHARGE WAS INADEQUATE**

The Commission should ensure that North Carolina applies industry-best methodologies and practices in the development of renewable energy integration techniques during a period in the electricity sector in which renewables will likely represent an increasing portion of the generation mix. Decisions regarding the integration of renewables will have both short-term and long-term impacts on the state and on all stakeholders involved.

Additionally, given our state's status as a national leader in renewable energy development, any integration study approved in North Carolina will undoubtedly be held up as an example in other regulated jurisdictions across the country that are assessing the integration of higher levels of renewable energy generation onto their grids. It is likely that any integration charge approved in North Carolina will be cited as support for similar charges in other jurisdictions. As the Commission has witnessed throughout this proceeding, parties have heavily referenced and relied upon solar integration studies that have been approved (or even simply proposed) in other jurisdictions to support their arguments relating to Duke's proposed Solar Integration Charge. Indeed, Duke recently filed nearly an identical Solar Integration Charge in the avoided cost proceeding before the South Carolina Public Service Commission, including the proposed settlement cap as part

of their initial filing.<sup>63</sup> As discussed below, because the methodologies and processes used to develop the proposed integration charges are insufficient, the charges should be rejected.

1. A NEW STUDY OF THIS TYPE MUST BE ADEQUATELY VETTED

Scientific studies and methodologies that are presented for the first time must demonstrate that they have received adequate review from unbiased parties and that their underlying methodology and resulting findings are sound. The review process amongst the parties to this proceeding that support the Solar Integration Charge is inadequate and does not rise to the level of scrutiny necessary for approval of a charge of this type.

The *Duke Initial Statement* initially proposed the Solar Integration Charge by presenting the results of the Astrapé Study. Duke and Astrapé have asserted that the LOLE<sub>flex</sub> metric is “well vetted” and has been applied in many other jurisdictions.<sup>64</sup> However, while Astrapé has utilized its LOLE<sub>flex</sub> model in the context of resource adequacy studies, it is not clear that they have applied the 0.1 LOLE<sub>flex</sub> metric to any renewable energy integration study of the type presented in this proceeding that has received approval from a utilities commission. Further, even if the 0.1 LOLE<sub>flex</sub> metric *had* been approved in another jurisdiction when applied in the same integration study context, which NCSEA and NCCEBA are not aware of having occurred, that does not give the metric and methodology presumptive validity in this jurisdiction.

Duke also claims that the Astrapé Study has been well vetted specifically in this proceeding. However, this “vetting” during the development of the study solely included

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<sup>63</sup> *Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Other Related Terms and Conditions*, South Carolina Public Service Commission, Docket Nos. 2019-185-E and 2019-186-E (August 14, 2019).

<sup>64</sup> Tr. Vol. 4, p. 205.

input from Duke employees and Astrapé.<sup>65</sup> Further, Duke and Astrapé engaged with the Public Staff during their negotiations with respect to the *Solar Integration Charge Stipulation*, which culminated in a closed-door settlement proposing the adoption of the Solar Integration Charge and the other provisions of the *Stipulation*. However, as revealed during the evidentiary hearing, Astrapé and Duke did not actually re-run their model in response to requests from the Public Staff. Instead, Astrapé applied “post processing techniques” to mimic what it expected the results of a re-run would be but did not provide the details of that methodology.<sup>66</sup>

Additionally, while NCSEA and NCCEBA appreciate the time and effort that the Public Staff spent considering the Solar Integration Charge and engaging in discussions with Duke and Astrapé regarding the study, the Public Staff’s witnesses testifying about the integration charge do not claim to have any prior direct experience with renewable energy integration issues or studies of this kind.<sup>67</sup> Moreover, although the Public Staff made efforts, very much appreciated by NCSEA and NCCEBA, to address various problems with the integration charge, in the end it is tasked with representing the using and consuming public, whose interests favor the largest integration charge possible, not with representing the interests of those parties who will pay the charge or serving as a neutral arbiter of disputed matters. As all parties have witnessed throughout this proceeding, the issues presented in the study, and included in a consideration of the integration of renewable energy more broadly, are extremely complex and would benefit from the input of experts with substantial experience with precisely these issues. The fact that the Public

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<sup>65</sup> *Id.*, p. 207.

<sup>66</sup> Tr. Vol. 4, pp. 174-175.

<sup>67</sup> Tr. Vol. 6, p. 404 (referring to Public Staff Witness Thomas’s statement of qualifications included in his testimony).

Staff communicated with Duke and Astrapé during the negotiation of the *Solar Integration Charge Stipulation* but did not consult with the expert witnesses of other parties with whom the Public Staff initially agreed, including a leading national expert in this field, further demonstrates that the Astrapé Study and the resulting Solar Integration Charge was not subject to adequate vetting as asserted by Duke and the Public Staff. This is particularly unfortunate since SACE Witness Kirby expressly stated during the evidentiary hearing that he would be willing to work with Astrapé and the Commission on the development of an integration study that addresses Witness Kirby's concerns.<sup>68</sup>

2. AN IMPORTANT STUDY OF THIS TYPE SHOULD GO THROUGH A TECHNICAL REVIEW COMMITTEE AND/OR STAKEHOLDER REVIEW

NCSEA and NCCEBA recommend that any study that forms the basis of an integration charge be developed and/or reviewed by a neutral third-party or committee that is able to assess the veracity of the study's methodologies and results, including the opportunity for stakeholder participation. As described in testimony and during the evidentiary hearing, it is common for studies of this type to be subject to a Technical Review Committee ("TRC") in order to evaluate and verify the methodologies and results of important utility studies that will have significant impact on stakeholders in the respective jurisdictions.<sup>69</sup>

During the evidentiary hearing SACE Witness Kirby described the TRC process as one that is frequently utilized "if you are going to do a new study, especially a study that introduces a new concept, a new study method, [or] a new metric."<sup>70</sup> A TRC should utilize

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<sup>68</sup> Tr. Vol. 5, p. 325.

<sup>69</sup> See, Tr. Vol. 5, pp. 123, 285; Tr. Vol. 6, pp. 61-62.

<sup>70</sup> Tr. Vol. 5, p. 285.

“a group of experts . . . [who are] genuine independent technical experts” who review the relevant study or methodology to assess “whether they think [the methodology] is appropriate and any improvements that need to be made.”<sup>71</sup> At the end of the process “you either get or don’t get the endorsement from the technical review committee, and if the technical review committee endorses it, then . . . everyone else kind of gets the feeling that . . . the way the study was done was a good way to do the study.”<sup>72</sup> Notably, the Idaho Power Solar Study, which has been discussed at length throughout this proceeding, utilized a TRC and, in fact, the administration of the final charge was the result of stakeholder agreement.<sup>73</sup>

Because the study of renewable energy integration in North Carolina is a relatively new issue, and the methodologies employed by the Utilities to support their proposed integration charges have not been adequately vetted in other jurisdictions or in North Carolina, this is precisely the type of situation in which a TRC, or a similar review process, would be appropriate.

More broadly, the important question of renewable energy integration also lends itself to communication and interaction amongst stakeholders regarding an appropriate, transparent, and fair resolution of these issues. This concept of requiring stakeholder interaction and discussion is not foreign to this Commission, and indeed, the Commission has encouraged or required stakeholder processes in a variety of contexts. The CPRE implementation process has included significant stakeholder involvement and collaboration to address a variety of important issues involved in the administration of the

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<sup>71</sup> *Id.*, p. 286.

<sup>72</sup> *Id.*, pp. 286-287.

<sup>73</sup> *Duke Reply Comments*, pp. 76-78; See *Kirby Cross Exhibit 2*.

competitive procurement process.<sup>74</sup> In the context of interconnection, the Commission's 2015 interconnection order directed the Public Staff to convene a stakeholder process two years later to investigate further reforms, and the Commission has also encouraged stakeholder collaboration on the ongoing interconnection queue reform process.<sup>75</sup> Parties have also been encouraged or required to collaborate on LEO formation and issues involving access to data.<sup>76</sup> NCSEA and NCCEBA believe that the integration of renewable energy is another area that would benefit from stakeholder interaction of this type.

#### B. THE ASTRAPÉ STUDY'S METHODOLOGIES ARE FATALLY FLAWED

The Astrapé Study incorporates multiple metrics, assumptions, and methodologies that are flawed and that have resulted in a proposed solar integration charge that is unsupported. Specifically, the Study applies the flawed LOLE<sub>flex</sub> metric that does not represent reasonable compliance with applicable NERC standards, improperly scales solar volatility data, uses limited historical data that has not been substantiated or compared to actual data in subsequent years, and fails to incorporate existing tools that Duke's own grid operators utilize to more efficiently manage grid imbalances. As a result of these deficiencies, the Astrapé Study must be rejected.

#### C. THE 0.1 LOLE<sub>FLEX</sub> METRIC IS INAPPROPRIATE

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<sup>74</sup> See, e.g., Docket Nos. E-2, Sub 1159 and E-7, Sub 1156 (e.g., requiring stakeholder meetings and reports of an independent administrator; the Commission holding a technical conference to discuss significant issues relating to the upcoming CPRE Tranche 2).

<sup>75</sup> See, *Order Approving Revised Interconnection Standard*, p. 27, Docket No. E-100 Sub 101 (May 15, 2015) (Requiring the Public Staff to convene a workgroup of interested parties not later than two years to evaluate the NCIP and to report recommendations to the Commission).

<sup>76</sup> See, *Sub 148 Order*, p. 108 (requiring the Utilities to solicit input on the revised NoC Form, make revisions to the form consistent with this order and the input received, and to file a revised form with the Commission as a part of the compliance filing required by this order); *Order Accepting DENC's and DEC's SGTP Updates, Requiring Additional Information from DEP, and Directing DEC and DEP to Convene a Meeting Regarding Access to Customer Usage Data*, Docket No. E-100 Sub 147 (March 7, 2018) (requiring data access stakeholder meeting and report).



1. THE 0.1 LOLE<sub>FLEX</sub> METRIC DOES NOT REPRESENT REASONABLE COMPLIANCE WITH ACTUAL NERC STANDARDS

Astrapé and Duke present the 0.1 LOLE<sub>flex</sub> metric as an appropriate model to reflect Duke's compliance with mandatory NERC reliability standards.<sup>77</sup> Throughout this proceeding SACE Witness Kirby has asserted that, based on his decades of experience with renewable energy integration and utility system balancing modeling, the 0.1 LOLE<sub>flex</sub> metric does not appropriately reflect compliance with actual NERC reliability standards. NCSEA Witnesses Beach and Johnson share Witness Kirby's concerns,<sup>78</sup> and the Public Staff initially agreed with Witness Kirby's assessment.<sup>79</sup> Throughout the proceeding, and particularly through extensive testimony during the evidentiary proceeding, parties and this Commission closely analyzed the 0.1 LOLE<sub>flex</sub> metric. Through this process a number of significant concerns have been investigated and clarified. First, the 0.1 LOLE<sub>flex</sub> metric does not accurately reflect reasonable compliance with NERC standards. Second, the evidence in this proceeding demonstrates that Duke may not have accurately calibrated its model to achieve reliable results, and further, correct calibration to a single year of historical data does not ensure that the model produces accurate results. More broadly, the Astrapé model does not account for less expensive alternatives to adding operating reserves that Duke has at its disposal to address renewable integration, and the Astrapé Study does not address the important question of whether Duke, in general, is holding more operating reserves than it needs to reasonably comply with NERC standards, at the expense of

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<sup>77</sup> Tr. Vol. 4, pp. 64-65.

<sup>78</sup> See, *NCSEA Initial Comments, Affidavit of Thomas Beach*, p. 18; *Affidavit of Dr. Ben Johnson*, p. 12.

<sup>79</sup> See, *Initial Statement of the Public Staff*, p. 36.

ratepayers. Because of these deficiencies the Study’s methodology, and its results, must be rejected.

Astrapé states that the 0.1 LOLE<sub>flex</sub> represents a single 5-minute non-compliance “event” every ten years.<sup>80</sup> Astrapé argues that because the model uses “perfect foresight,” and the hypothetical grid operator knows with certainty the net load it must meet in every upcoming five-minute period, a single LOLE<sub>flex</sub> 5-minute non-compliance “event” likely includes multiple NERC imbalances.<sup>81</sup> This, according to Astrapé and Duke, rebuts Witness Kirby’s assertion that the 0.1 LOLE<sub>flex</sub> metric is too stringent. However, Duke has obfuscated Witness Kirby’s position, and in purporting to refute the strawman argument they have created, Duke has directed attention away from the true problems with the 0.1 LOLE<sub>flex</sub> metric.

First, and of fundamental importance, while it may be true that a 5-minute non-compliance “event” under 0.1 LOLE<sub>flex</sub> includes multiple NERC imbalances, such an event does not actually correspond to a violation of the most relevant NERC standard—BAAL—or represent an actual loss of load event.<sup>82</sup> In other words, even though the Astrapé model includes “perfect foresight”, and any 5-minute non-compliance event will include multiple imbalances, the model still simulates utility operations that are significantly over-compliant with NERC standards. To be clear, a NERC *imbalance* does not constitute a NERC violation. The BAAL standard establishes a NERC violation only after thirty minutes of consecutive imbalances, not five minutes. It is for this reason that during the

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<sup>80</sup> Tr. Vol. 5, p. 177.

<sup>81</sup> Tr. Vol. 4, pp. 63-65.

<sup>82</sup> *See*, Tr. Vol. 6, p. 81 (Witness Kirby states “the [NERC standard] that really gives you more trouble for actually operating is the BAAL metric . . .”).

evidentiary hearing Witness Kirby referred to the 5-minute non-compliance event under the model, and the perfect foresight built into the model, as a “red herring.”<sup>83</sup> Witness Kirby explained that while a model would not want to push the thirty-minute BAAL limit, a five-minute limit is too stringent and fails to incorporate the necessary nuance of actual operations.<sup>84</sup> While compliance with the 0.1 LOLE<sub>flex</sub> metric will almost certainly represent compliance with the more relevant NERC BAAL standard, it also represents significant over-compliance with standard. In other words, not only is the 0.1 LOLE<sub>flex</sub> standard uncorrelated with the actual NERC standards (the “absolute” standard<sup>85</sup>), it is also uncorrelated with the standard by which a utility grid operator would actually operate its system (the “relative” standard<sup>86</sup>). As was discussed at the hearing, unnecessary overcompliance with the NERC standards results in unnecessary cost to the utility and to ratepayers; it also results in an integration charge that is too high. NCSEA and NCCEBA submit that it is in this respect that Witness Kirby asserts that the 0.1 LOLE<sub>flex</sub> metric is “too stringent.” Witness Kirby explained during the evidentiary hearing that a more appropriate model would evaluate and simulate a broader and more nuanced set of operating characteristics that more accurately reflect a utility’s actual operations to comply with NERC standards.<sup>87</sup> However, the inherent limitations of the SERVVM model as a resource adequacy model, rather than a renewable energy integration model, do not allow for this necessary level of complexity.

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<sup>83</sup> Tr. Vol. 6, p. 79.

<sup>84</sup> *Id.*, pp. 82-83.

<sup>85</sup> *See*, Tr. Vol. 6, p. 76 (Commissioner Clodfelter discussing the distinction between the “absolute standard” – NERC standards – and the “relative standard” – a reflection of actual utility operations in compliance with NERC standards).

<sup>86</sup> Tr. Vol. 6, p. 74.

<sup>87</sup> *See*, Tr. Vol. 6, pp. 80-89.

Building on the discussion above, however, because Astrapé calibrated the 0.1 LOLE<sub>flex</sub> metric – which does not represent reasonable compliance with NERC standards – from historical 2015 data, at least one of two things must be true. Either Duke did not accurately calibrate the model to appropriately reflect its actual operating reserves in 2015, or Duke was holding operating reserves in excess of what was needed to safely and reliably operate its system, at the expense of ratepayers. It is also possible that Duke both did not accurately calibrate the model and held operating reserves in excess of what was actually needed.

With respect to the proper calibration, during the evidentiary hearing Witness Kirby discussed the potential for error when calibrating a metric like the LOLE<sub>flex</sub>. He described the fact that calibrating the model to approximate historical 2015 operating reserves was “necessary but not sufficient” in that even if the model was calibrated such that a 0.1 LOLE<sub>flex</sub> roughly matched the single year of historical 2015 data, that does not ensure that the model would accurately produce necessary reserves to match that initial level once the solar volatility data and other model inputs were added in subsequent model years.<sup>88</sup> As discussed below, Duke has not demonstrated that the 0.1 LOLE<sub>flex</sub> model produced outputs that adequately aligned with actual operating reserves in the intervening years between 2015 and the present despite having the opportunity to do so. Additionally, Public Staff Witness Thomas testified that the Public Staff had confidence in the model because the 0.1 LOLE<sub>flex</sub> was calibrated to “actual reserves . . . that did not result in NERC violations” which assured the Public Staff that the model was “adequately calibrated.”<sup>89</sup> However, this analysis does not answer the question of whether the calibration was accurate and that the

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<sup>88</sup> Tr. Vol. 5, p. 295.

<sup>89</sup> Tr. Vol. 6, p. 412.

model, as calibrated, would produce accurate results in future model years. It also does not address whether a baseline that “did not result in NERC violations” was more stringent, and thus more expensive, than necessary.

With respect to the latter, whether Duke was or continues to be holding operating reserves in excess of what is needed to safely and adequately comply with NERC reliability standards, if Duke calibrated its 0.1 LOLE<sub>flex</sub> standard based on historical 2015 reserves, and the 0.1 LOLE<sub>flex</sub> metric represents significant overcompliance with NERC standards, it is possible that Duke has maintained operating reserves in excess of what is necessary to safely and reliably operate its system. There was significant discussion during the evidentiary hearing whether the baseline that Astrapé used as the “before” case to determine necessary operating reserves indicated that Duke maintained operating reserves in excess of what was needed to maintain sufficient reliability. Duke Witness Wintermantel stated that he was confident that the 0.1 LOLE<sub>flex</sub> metric was appropriate because “we know we met the NERC standards in 2015.”<sup>90</sup> However, this does not address whether the base case was excessively compliant. Duke Witness Wintermantel further acknowledged that “if the Companies were operating in a way where they . . . had significantly excess operating reserves, then . . . that would be an increase in cost.”<sup>91</sup> SACE Witness Kirby also stated that, in general, if an integration study modeled a system that had “excessively high reliability” and added reserves to maintain that excessively high reliability, “that would not be appropriate.”<sup>92</sup> As the Commission noted during the evidentiary hearing, it is a policy decision for the Commission whether Duke is maintaining an appropriate level of operating

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<sup>90</sup> Tr. Vol. 4, p. 190.

<sup>91</sup> Tr. Vol. 4, p. 189.

<sup>92</sup> Tr. Vol. 5, p. 233.

reserves.<sup>93</sup> A Commission finding that Duke could safely and reliably manage its grid while holding a lower level of operating reserves would further support the need for a revised integration charge study and should be incorporated into the more holistic review process that encapsulates both the costs and benefits of intermittent generation in North Carolina.

2. THE HISTORICAL DATA PROVIDED BY DUKE DOES NOT SUPPORT THE 0.1 LOLE<sub>FLEX</sub> METRIC

Duke and Astrapé acknowledged that they only used a single year of 2015 historical data in their Study to calibrate the 0.1 LOLE<sub>flex</sub> model.<sup>94</sup> This is not a sufficient amount of historical data to rely upon in preparing the model or validating its results. Duke Witness Wintermantel testified to the importance of utilizing historical data in determining ancillary service cost rates underlying the Solar Integration Charge, Specifically, Duke Witness Wintermantel, regarding the benefits of diverse generation on the grid and the need for sufficient data to extrapolate benefits from geographically diverse generation, stated that Duke “believes it is more appropriate to rely on actual historical data to set ancillary service cost rates at the time of the study and perform updates every two years. New data (not available during the study) will continually provide more guidance on solar volatility assumptions.”<sup>95</sup> Similarly, when testifying about the potential effects of intra-hour solar variability as related to geographically diverse generation, stated that the approach would be better if Duke updated the Astrapé Study “with real data every two years when the study is updated” to “capture true intra-hour diversity.”<sup>96</sup> In fact, Duke Witness Wintermantel

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<sup>93</sup> See, Tr. Vol 6, p. 76; Docket No. E-100 Sub 157.

<sup>94</sup> Tr. Vol. 4, pp. 119-120.

<sup>95</sup> Tr. Vol. 4, p. 103.

<sup>96</sup> Tr. Vol. 4, p. 182.

repeatedly testified to the importance of updating the Astrapé Study with real data in his testimony.<sup>97</sup>

NCSEA and NCCEBA agree with Duke and its Witness Wintermantel – in any given study regarding benefits and costs associated with distributed generation – real historical data should be utilized. Despite apparently understanding this, Duke has failed to substantiate why they only allowed a single year’s worth of data for the Astrapé Study. What Duke and its witnesses were unable to answer throughout the evidentiary hearing was why they did not use data that Duke already has in its possession to inform its model and validate the model’s results despite the fact they clearly take the position that historical data is necessary for accurate modeling.

**V. DUKE’S LATE-FILED EXHIBIT 2 FAILS TO VALIDATE THE ASTRAPÉ STUDY AND HIGHLIGHTS A DISCRIMINATORY STANCE AGAINST SOLAR**

NCSEA Witness Tom Beach asserted, and SACE Witness Kirby essentially agreed, that “the Duke study is based on a simulation, that is a modeling exercise, and not on actual experience.”<sup>98</sup> The Astrapé Study consisted of a set of simulations that were not validated against historical data, and, accordingly, was not sufficiently modeled. Duke Witness Wintermantel stated “I just don’t know” when asked whether it would have made sense to validate the Astrapé Study against Duke’s historical data<sup>99</sup> When confronted with the request for Duke to validate the Astrapé Study, Commissioner Clodfelter requested Duke

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<sup>97</sup> See, Tr. Vol. 4, p. 69 (“The uncertainty surrounding future diversity benefit further supports the need to update this Study every two years as laid out in Mr. Snider’s testimony.”); p. 199 (“And then I think the approach of updating this every two years is substantial.”); and, p. 203 (“We self-identified that in the study, that those high penetration levels, we – they’re highly uncertain. And so that has been the stance of [Duke] through this whole process is, this needs to be updated every two years. We’re getting changes to the system that will effect these results.”).

<sup>98</sup> Tr. Vol. 5, p. 131.

<sup>99</sup> See, Tr. Vol. 4, pp. 224-226.

provide categorized, yearly data from 2014 until the present. Duke failed to do this. Moreover, what Duke presented did not validate its model and, instead, presented a bar graph, apparently inflated by non-solar factors, such as coal or natural gas prices, which shows the 60-minute interval ramping needs from operating reserves.

Specifically, the Commission requested that Duke provide historical operating reserve data from 2014-2018, including a breakdown by the type of reserve.<sup>100</sup> Duke purported to comply with this requirement in its Late-Filed Exhibit No. 2, filed on August 2, 2019, but failed to comply with Commissioner Clodfelter’s request – Duke did not provide the breakdown by reserve type that was requested at the hearing.<sup>101</sup> Further, the information that Duke has provided, Duke’s actual total operating reserves in years 2015-2018, and modeled 2020 “No Solar Case” and “Existing Plus Transition Solar” under 0.1 LOLE<sub>flex</sub>, does not compare the Astrapé model’s projections of operating reserves against actual operating reserves, which would have assisted the Commission in further assessing the strength of the correlation between the model and actual operations. Duke also did not include data from 2014, indicating that they did not readily have access to the 2014 data and would be required to manually retrieve, process, and validate archived 2014 data.<sup>102</sup> During the evidentiary hearing the Commission noted that reviewing the actual operating reserves that Duke maintained for years 2016 to 2018 could provide additional confidence that the model was an adequate surrogate for Duke’s operations in compliance with NERC standards.<sup>103</sup> Despite having the opportunity to do so, Duke and Astrapé have not provided

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<sup>100</sup> Tr. Vol. 5, pp. 291-292 (Commission Clodfelter requesting that Duke provide both the aggregate number of reserves as well as the individual categories of “regulating reserves, load following reserves, and contingent reserves, and so on.”).

<sup>101</sup> Late Filed Exhibit No. 2, p. 3.

<sup>102</sup> *Id.*, p. 2.

<sup>103</sup> Tr. Vol. 5, p. 297.



the additional data that would assist the Commission in discerning the strength of the Astrapé model in estimating operating reserve requirements in the intervening years between 2015 and the present, and the late-filed exhibit from Duke does not substantiate the need for the solar integration charge, nor does it validate the findings from the Astrapé Study.

Further, in the *Solar Integration Charge Stipulation*, Duke and the Public Staff explain the intent of the Solar Integration Charge: “[t]he Integration Services Charge is designed to recognize the impact on the Companies' operating reserves, or generation ancillary service requirements, of integrating existing and new variable and non-dispatchable solar capacity and to assign such costs to solar QFs whose integration is causing the increased operating costs.”<sup>104</sup> From this definition, Duke’s witness testimony, and the filings made by Duke, it is clear that the Solar Integration Charge is informed by the need to incorporate higher operating reserves, or ancillary services, onto the grid to offset generation variability. Duke’s Late-Filed Exhibit 2 shows how the premise of the Solar Integration Charge is faulty and discriminatory against solar.

In Late-Filed Exhibit No. 2, Duke states “[c]hanges from year to year in realized operating reserves are impacted by a number of factors, including, but not limited to, coal prices, natural gas prices, resource retirements/additions, generator outages/maintenance, and increases in installed solar.”<sup>105</sup> While Duke further states that since 2015 the “increasing need for operating reserves” are “due to increases in installed solar”<sup>106</sup>, Duke

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<sup>104</sup> *Solar Integration Charge Stipulation*, p. 2 (paraphrasing *Duke’s Initial Statement*).

<sup>105</sup> Late-Filed Exhibit 2, p. 1.

<sup>106</sup> *Id.*

does not contextualize or otherwise provide a basis for how much variance in the need for operating reserves is directly caused by increased solar installs.

In the “Additional Notes” section of Late-Filed Exhibit 2, Duke states that the “relatively high operating reserves in 2015 were primarily due to higher coal commitment associated with lower coal prices.”<sup>107</sup> While NCSEA and NCCEBA do not contest the assertion that there was more coal in the generation mix in 2015, this singular explanation for increased coal provides some context to 2015, but such context is not provided for the other years. More importantly, Duke does not state why solar is being treated differently than other generation sources which may require additional operating reserves. This treatment discriminates against solar, when any component of Duke’s generation mix, including coal as recently as 2015, may increase the need for operating reserves requirements in any given year. As set forth above, Duke has asserted the Solar Integration Charge is intended to counter increased costs associated with increased operating reserves and the related maintenance of such reserves. Duke has not stated how they intend to safeguard solar generation from being charged for the shortcomings of other generators. What is to protect solar developers from being charged an integration charge based upon charges due to conditions related to some other part of the generation mix, such as coal or natural gas prices, which require additional operating reserves?

Duke will likely assert that the two-year review and refresh will act as a means to safeguard against such overpayment being made by solar QFs. Duke may also likely present data that shows load-following that goes up and down with solar volatility against historical data (which they have notably failed to do thus far). However, even such data

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<sup>107</sup> *Id.* at 2.

does not necessarily reflect the underlying value of the solar, whose variability may be present but also whose presence allowed for overarching move away from non-economic generation, such as coal, which, as shown in Late-filed Exhibit 2, also can require high amounts of operating reserves for its own unique generation profile idiosyncrasies. Furthermore, and perhaps most-importantly, the Late-filed Exhibit 2 bar graph utterly fails to provide data that matches the expectations that Duke forecasts when talking about 5-minute intervals and “perfect foresight”<sup>108</sup> How can Duke reasonably expect the model to have “perfect foresight” for 5-minute time steps when the requested validation data does not reflect 1) solar variability or 2) a clear differentiation between the solar variability effect on operating reserves against other issues which might cause increased operating reserves, such as coal ramping.

## **VI. THE ASTRAPÉ STUDY INCORPORATES A LARGE NUMBER OF UNSUPPORTED ASSUMPTIONS**

In addition to the modeling deficiencies described above, the Astrapé Study includes a broad range of assumptions that further call into question the veracity of the methodology and the results. These issues compound the methodological and process flaws addressed above.

### **A. THE SOLAR VARIABILITY DATA USED IN THE ASTRAPÉ STUDY IS FLAWED**

The Astrapé Study utilized projected solar variability data in its model as a key metric to determine the Solar Integration Charge.<sup>109</sup> Duke Witness Snider stated, in response to a question from Commissioner Clodfelter regarding Duke’s focus on intra-hour

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<sup>108</sup> “We are modeling in our model 5-minute time steps. The model has perfect foresight.” Tr. Vol. 6, p. 20.

<sup>109</sup> Astrapé Study, p. 7.

variability rather than hour-to-hour variability, that the Astrapé Study fills a void where there were not prior models outlining this volatility issue on an intra-hourly basis.<sup>110</sup> However, this assertion ignores significant advances in models across the country when reviewing intra-hour solar generation variability.<sup>111</sup> This is a major flaw given the model's basic reliance on short-time-interval divergence from predicted net load, especially given the mass of resources available on the subject as indicated here.

The Astrapé Study also failed to adequately account for the geographic diversity of distributed solar. Weather is not uniform across the Duke territories at any given time, and, therefore, it logically follows that any Duke model should use both historical data for weather across a variety of geographic areas and also predict forward an ever-diversifying solar generation facility portfolio across the southeast, including neighboring utilities. Duke Witness Wintermantel states that, even with the limited Astrapé Study, there were diversity benefits in the results: "[w]hile Astrapé calculates a relatively small amount of diversity benefit during the 2016 - 2018 time period, the Companies emphasize that these projections are not guaranteed to materialize and do not incorporate the impact that large solar projects may have on the volatility when added to the system."<sup>112</sup> Of course, Duke

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<sup>110</sup> "I think what we were looking at is what is that intra-hour -- that was -- when we look at operating reserves, we've always, as an industry, have accepted the fact that you have to balance minute to minute. Traditionally, you don't have a production cost model, they're at that minute time step, especially in my world when I'm looking out 30 years. So the question we -- as we interpreted it from the Commission in 148 was, how does -- you know, how does this intra-hour -- how does the intermittency -- how does the non-dispatchable intermittent nature affect the Company?"

And we went to, well, what does that do to the intra-hour component that we haven't been modeling prior to Sub 158, this proceeding?" Tr. Vol. 4, p. 10.

<sup>111</sup> In addition to the Idaho Study referenced herein, several other resources on solar intra-hour variability were available to Duke when it engaged and employed Astrapé to conduct its study including, but not limited to: from the U.S. Office of Energy Efficiency & Renewable Energy (<https://www.energy.gov>); from the National Renewable Energy Laboratory (<https://www.nrel.gov>); and from the Solar Electric Power Association (<https://pdfs.semanticscholar.org>). All of the above-listed studies or resources involve a much more robust and verified range of outcomes than the Astrapé Study.

<sup>112</sup> Tr. Vol. 4, pp. 102-103.

Witness Wintermantel downplays the promise of diversity benefits in stating that increased solar will likely result in increased variability and states that Duke can continually update these models every two years to show diversity benefits. Duke Witness Wintermantel's statement does not address why Duke and Astrapé have not utilized the historical data available to them now which could be incorporated into the Astrapé model and allow for more meaningful findings.

Further, as addressed by SACE Witness Kirby, Duke's assumption that short-term solar variability will scale linearly ignores well-established principles of solar variability and scaling.<sup>113</sup> Duke's response that it factored in decreased variability in its model by using a 75% of the baseline variability for its 1,500+ MW scenario is also insufficient. This 75% assumption does not create an appropriate parameter for realistic solar variability. Despite this deficiency, however, it is important to note that the projected Solar Integration Charge, even using the flawed 75% assumption, decreased the projected Solar Integration Charge by 70% in DEC and 34% in DEP, highlighting the significant of accurate variability projections and measurements.<sup>114</sup>

The Astrapé Study's baseline assumption—that more solar will result in the need for more operating reserves—also contradicts actual experience in other jurisdictions. NCSEA Witness Beach's testimony shows that the California Independent System Operator ("CAISO"), an operator for a state with a significantly higher amount of distributed solar and wind generation sources,<sup>115</sup> did not see increased ancillary benefits

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<sup>113</sup> Tr. Vol. 5, pp. 194-197.

<sup>114</sup> Astrapé Study, pp. 47, 50 (In DEC, the projected Solar Integration Charge for the 1,500+ MW scenario was \$9.75/MWh and decreased to \$2.90/MWh at 75% variability. In DEP, the projected Solar Integration Charge for the 1,500+ MW scenario was \$14.91/MWh and decreased to \$9.72/MWh at 75% variability.).

<sup>115</sup> "The DEC/DEP Astrapé study modeled a maximum of 3,020 MW of solar on DEC and 4,610 MW of solar on DEP, for a total of 7,630 MW on a system with a coincident peak of about 32,000 MW . . . This is

costs “over a 13-year period in which the amount of wind and solar resources integrated by the CAISO has increased nine-fold.”<sup>116</sup> Duke’s retort to NCSEA Witness Beach’s testimony and report was simply to note the increase in the ancillary services costs between 2015 and 2016 (“Ancillary service costs increased to \$119 million in 2016, nearly doubling from \$62 million in 2015.”<sup>117</sup>). However, as NCSEA Witness Beach points out, the cost of ancillary services has minimally increased since 2006, and those years when ancillary services prices go down (i.e., 2014 and 2015) are “dry” years when hydroelectric generators participate more heavily in the ancillary services market.<sup>118</sup> In fact, in 2006 the ancillary services costs as a percentage of market prices was only 2%, higher than any year since then and, when including the savings from the Energy Imbalance Market (“EIM”), was nearly double the ancillary services costs as a percent of market prices in 2018.<sup>119</sup> As NCSEA Witness Beach notes, the Astrapé Study “is based on a simulation, that is a modeling exercise, and not on actual experience.”<sup>120</sup> This is a fundamental flaw in the Astrapé Study. It is merely a projection model, with a single year of real, historical data, and the data it does have does not meaningfully show how solar integration interacted with the operating reserves or otherwise caused costs and benefits to the utilities and the ratepayers.

B. THE ASTRAPÉ STUDY MAKES UNSUPPORTED QUALITATIVE AND QUANTITATIVE ASSUMPTIONS ABOUT FUTURE SOLAR ADDITIONS

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similar to the penetration of wholesale solar on the CAISO system today, but the CAISO also integrates 8,000 MW of grid-connected, behind-the-meter solar.” Tr. Vol. 5, p. 117, fn. 6.

<sup>116</sup> Tr. Vol. 5, p. 131.

<sup>117</sup> Tr. Vol. 4, p. 103, citing a 2016 annual report from California, (<http://www.caiso.com>)

<sup>118</sup> Tr. Vol. 5, pp. 112-113.

<sup>119</sup> Tr. Vol. 5, p. 119.

<sup>120</sup> Tr. Vol. 5, p. 131.

The Astrapé Study makes a variety of assumptions regarding the quantity and quality of solar energy generation that will exist in the Companies' service territories in coming years. First, the model assumes that a certain level of solar capacity will come online in the respective time horizons included in the study, and this input is used to drive the solar variability data discussed above. Duke Witness Wintermantel described this assumption regarding future capacity as “really a major variable in the study” that significantly impacts the study results. As all parties appear to recognize, however, future capacity additions are uncertain.

Significantly, the model also assumes that all future solar capacity will not be “controlled” and therefore will contribute to the volatility that the model intends to solve for.<sup>121</sup> As was discussed at length during the evidentiary hearing, many future solar projects may include battery storage which will help to manage and alleviate intermittency and volatility concerns. In the recent CPRE Tranche 1, all winning projects are subject to full curtailment rights by Duke and two of those projects are solar + battery-storage facilities.<sup>122</sup> Additionally, in Duke's recent IRP filings, Duke included nearly 300 MW (nameplate) of lithium-ion battery storage as capacity resource placeholders which were assumed to provide 80% of their nameplate capacity towards meeting the Companies' winter peak capacity.<sup>123</sup> Astrapé did not reflect how that would affect solar volatility, if at all, given that it is utility scale battery storage within the complete control of Duke and could be utilized to affect peak. Astrapé also did not model any further battery storage to be added

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<sup>121</sup> *Beach Affidavit*, p. 20.

<sup>122</sup> *Updated CPRE Tranche 1 Final Independent Administrator Report*, Docket Nos. E-2, Sub 1159 and E-7, Sub 1156 (July 23, 2019).

<sup>123</sup> See, DEP and DEC's *2018 Integrated Resource Plans and 2018 Renewable Energy and Energy Efficiency Portfolio Standard Compliance Plans*, Docket No. E-100, Sub 157 (September 5, 2018).

to the grid to take advantage of surplus of summery solar generation, which Duke has not explained.

The *Solar Integration Charge Stipulation* between Duke and the Public Staff includes a provision that “controlled” solar facilities will not be subject to the integration charge. Although it is not yet clear what criteria Duke would impose on projects to be considered “controlled”, Duke at least acknowledges that future solar projects – which are currently modelled in the study – may not contribute to the need for any additional ancillary services as defined in the study. Despite this fact, the study models all future solar capacity as “uncontrolled.”

C. THE ASTRAPÉ STUDY INCORPORATES RESOURCE ADEQUACY STUDIES THAT ARE DISPUTED

Duke Witness Wintermantel also describes the connection between the Astrapé Study and the Astrapé Resource Adequacy Studies that Duke has presented and relied upon in this proceeding and the IRP proceeding. In response to questions from the Commission, Witness Wintermantel stated that the Ancillary Services Study is “very much . . . consistent” with and incorporates “all the load volatility and all the underlying probabilistic assumptions” of the Resource Adequacy Studies.<sup>124</sup> Significantly, however, the Astrapé Resource Adequacy Studies—which Companies rely upon to assert that they are winter-planning utilities and to derive the avoided capacity rate designs and the capacity seasonal weighting allocations—are contested in both this proceeding and the IRP proceeding. NCSEA Witness Johnson has expressed concern that the Resource Adequacy Studies are deficient, and SACE Witness Wilson testifies that a number of the assumptions included

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<sup>124</sup> Tr. Vol. 6, p. 48.



in the Resource Adequacy Studies are improper.<sup>125</sup> The Public Staff has also questioned the methodologies and findings of the studies.<sup>126</sup> The Commission expressly stated in its E-100 Sub 148 Order that it would be receptive to revisiting the Resource Adequacy Studies and the issues implicated by them in future avoided cost cases.<sup>127</sup>

In the Commission's August 27, 2019 *Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses* in Docket E-100 Sub 157, the Commission requested further comments from parties including the Public Staff, SACE, and NCSEA, and scheduled oral arguments on Duke's reserve margin findings, which are directly tied to the Astrapé Resource Adequacy Studies incorporated into the Astrapé Study. The incorporation of the contested methodologies included in the Astrapé Resource Adequacy Studies to the Astrapé Study further calls into question the multitude of assumptions that directly impact the proposed integration charge.

D. THE ASTRAPÉ STUDY DOES NOT CONSIDER OR INCORPORATE TOOLS THAT DUKE'S OWN SYSTEM OPERATORS APPLY TO MORE COST-EFFECTIVELY INTEGRATE SOLAR

In addition to the question of the appropriateness of the 0.1 LOLE<sub>flex</sub> metric, the question also remains whether, rather than simply adding operating reserves to maintain existing levels of reliability, Duke currently has more cost-effective ways to integrate renewable energy onto its grid. To this point, SACE Witness Kirby included in his Direct Testimony and described during the evidentiary hearing a Duke Energy presentation to the

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<sup>125</sup> Tr. Vol. 5, pp. 335-341.

<sup>126</sup> See Public Staff Comments in *Joint Report of the Public Staff; Duke Energy Carolinas, LLC; and Duke Energy Progress, LLC*, Docket No. E-100 Sub 147, pp. 9-17, (April 2, 2018).

<sup>127</sup> *Sub 148 Order*, p. 61.

NERC Operating Committee from June 2019. Witness Kirby described the presentation in which Duke recounted recent operational experience whereby Duke's system operators were able to "detune" their automatic generation control ("AGC") such that the AGC did not have to "chase . . . fast minute-to-minute deviations" which resulted in "better performance on the BAAL . . . metric, and . . . negligible impact on the CPS1" standard.<sup>128</sup> In other words, rather than attempting to chase fleeting balancing events every five minutes, Duke operators actually slightly relaxed their standards and found that they were able to maintain or improve performance on the BAAL standard. As correctly recognized by the Commission during the hearing, this practice by Duke operators reflects a "non-resource additional way of managing the issue of volatility" and is "an operational change . . . rather than a resource change."<sup>129</sup> Critically, the 0.1 LOLE<sub>flex</sub> metric does not incorporate the very operational changes that Duke's actual system operators have found to be effective tools to account for changes to volatility and instead applies a methodology that incorporates only a significantly more expensive resource-based change. NCSEA and NCCEBA recommend that a revised integration study consider these types of cost-saving operational changes which reflect actual operational experience.

**VII. THE SOLAR INTEGRATION CHARGE STIPULATION BETWEEN DUKE AND THE PUBLIC STAFF SHOULD BE REJECTED**

On May 21, 2019, Duke and the Public Staff filed the *Solar Integration Charge Stipulation*, which included the application of the "average" ancillary service costs of \$1.10/MWh for DEC and \$2.39/MWh for DEP that was included in the Astrapé Study and Duke's initial avoided cost application. The *Solar Integration Charge Stipulation* also

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<sup>128</sup> Tr. Vol. 6, p. 94 (SACE Witness Kirby describing Duke's findings).

<sup>129</sup> Tr. Vol. 6, p. 95.

included a “cap” to the Solar Integration Charge that would apply to each project subject to the Solar Integration Charge during the vintage in which the Solar Integration Charge was applied. For the E-100 Sub 158 vintage, the *Solar Integration Charge Stipulation* included a cap of \$3.22 for DEC and \$6.70 for DEP.<sup>130</sup>

Additionally, the *Solar Integration Charge Stipulation* stated that if a solar generator “can demonstrate that the facility is capable of operating, and shall contractually agree to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements (as reasonably determined by the Companies), through inclusion of energy storage devices, dispatchable contracts, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generators (‘controlled solar generators’).”<sup>131</sup>

As an initial matter, Duke and the Public Staff state in the *Solar Integration Charge Stipulation* that “[t]he Stipulating Parties agree that the Astrapé Study’s data, methodology, results, and conclusions are reasonable for purposes of quantifying the Companies’ ‘average’ and ‘incremental’ ancillary services costs attributable to integrating solar generation, as well as for purposes of calculating the Companies’ Integration Services Charge.”<sup>132</sup> As described above, the Astrapé Study’s data, methodology, results, and conclusions are not reasonable and should be rejected by the Commission. As a result, the *Solar Integration Charge Stipulation* should be rejected outright.

Further, a key provision of the settlement, the ability of a solar generator to avoid the integration charge if it is a “controlled solar generator” has not been adequately

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<sup>130</sup> *Solar Integration Charge Stipulation*, p. 9.

<sup>131</sup> *Id.*, p. 5.

<sup>132</sup> *Id.*, p. 6.

detailed, and solar generators – as well as the Commission – do not know what would be required for a solar generator to avoid the Solar Integration Charge. Additionally, the “cap” included in the *Solar Integration Charge Stipulation* is arbitrary, incorporates the flawed assumptions of the model, and would likely require solar facilities to assume that the arbitrary cap would apply to projects that they constructed under the standard offer or the H.B. 589 programs, inflating costs to ratepayers or frustrating H.B. 589 programs. Critically, the *Solar Integration Charge Stipulation* also fails to address whether and to what extent the Solar Integration Charge would apply to H.B. 589 programs, and Duke and the Public Staff have demonstrated that they do not agree as to whether or how the charge would be applied to these programs. For these reasons, as discussed below, the *Solar Integration Charge Stipulation* should be rejected.

A. THE SOLAR INTEGRATION CHARGE STIPULATION FAILS TO DESCRIBE HOW A SOLAR GENERATOR WOULD QUALIFY AS A “CONTROLLED SOLAR GENERATOR”

As part of the *Solar Integration Charge Stipulation*, Duke and the Public Staff agreed that a solar generator that “can demonstrate that the facility is capable of operating, and shall contractually agree to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements (as reasonably determined by the Companies), through inclusion of energy storage devices, dispatchable contracts, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generators (‘controlled solar generators’).”<sup>133</sup> Pursuant to the *Solar Integration Charge Stipulation*, this determination would be subject to the Companies’ discretion,<sup>134</sup>

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<sup>133</sup> *Id.*, p. 5.

<sup>134</sup> Under no circumstances should the actions necessary to mitigate any Solar Integration Charge be left to Duke’s discretion rather than being approved by this Commission.

and the *Solar Integration Charge Stipulation* does not describe what would be required for solar generators to be considered “controlled solar generators.”

NCSEA and NCCEBA appreciate the effort by the Public Staff to provide for a provision that permits a solar generator to avoid any solar integration charge if it is capable of being operated such that it may reduce intermittency concerns, and NCSEA and NCCEBA appreciate Duke’s acknowledgement of the ability of solar facilities to mitigate the need for any integration charge. As parties have described throughout this proceeding, coupling solar facilities with battery storage can provide a variety of tools to increase operational efficiencies, maximize the value of renewable generation, and save ratepayers money. NCSEA and NCCEBA agree that as battery storage continues to become more cost-competitive, it should be integrated into the grid with greater regularity, and NCSEA and NCCEBA look forward to continued discussions before this Commission and in North Carolina on the topic of energy storage and other tools to address the integration of renewable energy onto the grid.

With respect to the specific provision in the *Solar Integration Charge Stipulation* before the Commission in this proceeding, however, members of NCSEA and NCCEBA will have no way of knowing what would be required of them to be considered a “controlled solar generator.” Duke witness Snider acknowledged this during the evidentiary hearing and stated that Duke considered it “more appropriate that we’re addressing the storage protocol as part of 589, and that we would take this into consideration” in the context of H.B. 589 programs rather than during the avoided cost proceeding.<sup>135</sup> Duke’s position is

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<sup>135</sup> Tr. Vol. 3, p. 33. However, to NCSEA’s knowledge, there have been no discussions in the context of CPRE Tranche 2 about how storage additions might mitigate any integrations charge. Indeed, there has been no substantive discussion of the integration charge at all. Rather, the discussion of storage has focused sole

that they would negotiate such terms in a PPA in the future to establish the necessary pre-requisites for a solar facility to avoid the integration charge.<sup>136</sup>

Despite Duke's assurances that it will work with NCSEA and NCCEBA members and other stakeholders in the future to establish a storage protocol and will negotiate PPAs in good faith to incorporate the protocol or other means by which a solar facility can avoid the integration charge, Duke will hold tremendous leverage during any such negotiations because a solar facilities' only alternative to accepting Duke's proposed requirements would be the imposition of an integration charge, including assumptions regarding the cap, which may make the project financially unviable.

NCSEA and NCCEBA request that the Commission reject the *Solar Integration Charge Stipulation* and the Solar Integration Charge given a major provision affecting the impact of the Solar Integration Charge on QFs is currently unknown and is subject to future negotiation. To approve the Solar Integration Charge with this key issue unresolved would be akin to tis Commission approving and requiring QFs to enter a contract in which a material term is left open-ended such that neither contracting party knows at the time of contract formation what the benefit of the bargain will be. Significantly, in this analogy, the party that would be most directly impacted by the unknown term—NCSEA and NCCEBA members—would not even be a party to the agreement and would be required to negotiate that term in the future. For the reasons described above, because the “controlled solar generator” provision is a critical component of the *Solar Integration*

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on the appropriate protocols for the operation of storage resources that may be included in a CPRE PPA. This has nothing to do with how storage resources must be operated to reduce ancillary services costs and mitigate any Solar Integration Charge.

<sup>136</sup> *Id.*, pp. 33-34.

*Charge Stipulation* and has not been adequately defined or described, NCSEA and NCCEBA request that the Commission reject the *Solar Integration Charge Stipulation*.<sup>137</sup>

B. THE PROPOSED “CAP” IS ARBITRARY AND SHOULD BE REJECTED

The *Solar Integration Charge Stipulation* includes a proposed “cap” that would be applied to solar generators subject to the integration charge. The cap for a specific solar facility would be calculated during and linked to the integration charge vintage that applied to the solar facility. For the E-100 Sub 158 vintage, the *Solar Integration Charge Stipulation* proposes a cap of \$3.22 for DEC and \$6.70 for DEP.<sup>138</sup>

To arrive at the cap, Duke and the Public Staff agreed to the following methodology:

The Cap shall be based upon the Companies’ incremental ancillary services costs for the last 100 MW of solar generation forecasted to be installed within the biennial vintage period. Specific to the current 158 Vintage, the Stipulating Parties agree that the cap should be developed based upon the Companies’ 2018 Integrated Resource Plans’ (“IRP”) projections of installed solar at the end of the current Sub 158 biennial period (2020). DEC’s 2018 IRP forecasts 1,588 MW of installed solar generation in 2020, while DEP’s 2018 IRP forecasts 3,061 MW of installed solar generation in 2020.<sup>139</sup>

Thus, to establish the cap, the *Solar Integration Charge Stipulation* starts with an assumption about how much solar is going to come online over the next two years based on the Companies’ IRPs. From that assumption, the model would look to the last 100 MW

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<sup>137</sup> This is all the more the case given that the Solar Integration Charge represents a major new policy that has the potential to significantly limit solar development in the state based, as discussed above, on highly imperfect modeling and analysis and a flawed development process. Even if the Commission were inclined to overlook these problems, it should not impose a Solar Integration Charge without clear direction on how it can be mitigated.

<sup>138</sup> *Solar Integration Charge Stipulation*, p. 9.

<sup>139</sup> *Id.*

of solar projected to come online and determine the projected “incremental cost” to integrate that last 100 MW. Notably, Duke has not proposed to apply the incremental cost in the context of the integration charge itself, only in the cap. Modeling the cap also incorporates the assumptions and methodologies in the Astrapé Study and model, including assuming that the last 100 MW of solar generation will be “uncontrolled.”

The *Solar Integration Charge Stipulation* also does not address whether the cap would apply equally to solar projects with 5-year, 10-year, or 20-year terms. Given NCSEA’s and NCCEBA’s position, as discussed below, that in this proceeding the Commission may only address an integration charge as it relates to PURPA QFs, not CPRE and GSA projects, any cap will primarily have relevance to five-year PPAs.<sup>140</sup> That means that under the *Solar Integration Charge Stipulation* there would only be one biennial adjustment to the applicable charge, subject to the cap. Given that fact, and all of the uncertainty and problems associated with the cap, it is difficult to comprehend the case for making any adjustment at all during the life of the initial PPA, rather than making an adjustment upon PPA renewal if needed. The goal of the *Solar Integration Charge Stipulation* is to eventually have all covered facilities paying the appropriate average integration charge. That is why the initial charge for new facilities is based on the average and any upward adjustment would similarly be based on the average as computed for the next biennium. This goal could be much better and more reasonably accomplished simply by adjusting any integration charge for five-year PPAs upon contract renewal.<sup>141</sup>

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<sup>140</sup> There is no indication that there will be a material number of 1 MW 10-year PURPA PPAs executed and in any case they will not be a significant part of the generation mix given the statutory 100 MW limitation for each Duke utility.

<sup>141</sup> It should also be noted that a cap that allows for an almost 300% increase in the charge over a two-year period is unreasonable on its face.



Moreover, the evidence in this proceeding has demonstrated that renewable energy integration charges often decrease as utilities adapt and learn to better manage the integration of renewables.<sup>142</sup> Despite this, the cap included in the *Solar Integration Charge Stipulation* is based on the estimated “incremental” rate, which incorporates a wide range of assumptions called into question in this proceeding, and would directly impact the financial assumptions that solar generators would have to make when financing their projects or when participating in H.B. 589 programs. Duke Witness Snider agreed during cross-examination that QFs bidding into the CPRE program would have to assume the full cap would apply during the contract, stating “if I was evaluating it and was a bidder, I would say it starts with my base case being the charge as implemented and my tail risk is the cap.”<sup>143</sup> Public Staff Witness Thomas stated that he could not “speak to the ability of QFs to . . . obtain financing with or without the cap.”<sup>144</sup> For those projects, the cap would not be theoretical or subject to future revision like the assumptions in the study; rather, it would directly impact the viability of projects in the near term.

C. IT IS INAPPROPRIATE TO ADDRESS THE APPLICATION OF AN DUKE AND THE SOLAR INTEGRATION CHARGE TO H.B. 589 PROGRAMS IN THIS PROCEEDING, BUT IF IT IS ADDRESSED, IT SHOULD BE REJECTED

As proposed, the Solar Integration Charge would clearly apply to standard offer and negotiated PPAs entered into during the Sub 158 vintage. It would also apply to renewals of any existing standard offer and negotiated QF PPAs after the expiration of their

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<sup>142</sup> NCSEA Witness Beach’s testimony shows that the California Independent System Operator (“CAISO”), an operator for a state with a significantly higher amount of distributed solar and wind generation sources, did not see increased ancillary benefits costs “over a 13-year period in which the amount of wind and solar resources integrated by the CAISO has increased nine-fold.” Tr. Vol. 5, p. 131.

<sup>143</sup> Tr. Vol. 3, p. 28.

<sup>144</sup> Tr. Vol. 6, p. 422.

initial term. However, the *Solar Integration Charge Stipulation* does not make clear whether or how the Solar Integration Charge would apply to the primary renewable energy procurement programs under H.B. 589: CPRE and GSA. Further, despite entering into the *Solar Integration Charge Stipulation*, Duke and the Public Staff have expressed different positions during the evidentiary hearing with respect to their expectations regarding the Solar Integration Charge's application to these programs.

During the evidentiary hearing, Duke stated that it expected the Solar Integration Charge to apply to CPRE Tranche 2.<sup>145</sup> The Public Staff indicated that they thought that the Solar Integration Charge *could* apply to Tranche 2, but they were not yet certain as to the specifics of that application.<sup>146</sup> In the context of the GSA program, Duke and the Public Staff have both admitted that they do not know how the integration charge would apply. Duke witness Snider stated that Duke has “not done any analysis” with respect to the application of the integration charge to GSA, and Public Staff witness Thomas states that “[a]t this time we don't have a position on . . . how that charge might be applied [to the GSA program]. We haven't spoken internally about it.”<sup>147</sup>

This confusion aside, it is simply improper for the applicability of any Solar Integration Charge to CPRE and GSA to be decided in this docket. Those programs have been developed under separate dockets with different parties and different interested members of the public, all of whom should have the opportunity to participate in any decision making that will have a substantial impact on those programs. Moreover, CPRE and GSA are complex, multi-dimensional programs; a major new component should not

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<sup>145</sup> Tr. Vol. 2, p. 290.

<sup>146</sup> Tr. Vol. 6, pp. 428-429.

<sup>147</sup> Tr. Vol. 3, p. 32; Tr. Vol. 6, p. 430.

be added to either program without careful consideration of how it may affect the program as a whole.

However, if the Commission should elect to take up the applicability of a Solar Integration Charge to CPRE and GSA in this proceeding it should reject the idea. As the Commission noted during the hearing, significant CPRE Tranche 2 milestones are either currently underway or rapidly approaching.<sup>148</sup> In addition to the significant question of whether the Commission will have issued a final decision with respect to the Solar Integration Charge prior to the opening of Tranche 2 bids, there are a number of outstanding questions that would have a significant impact on the Tranche 2 process.

First, it is unclear how the Solar Integration Charge would be applied in the context of the CPRE program in general. The 20-year avoided cost rate is used to establish the bidding cap in the CPRE program, but it is not directly tied to CPRE pricing other than setting the cap. NCSEA and NCCEBA are not clear from the evidence presented during this proceeding how the Solar Integration Charge would be incorporated into the cap, into bidding requirements, or into Tranche 2 documents. The Public Staff also recognized the added complication of applying the Solar Integration Charge to the CPRE program, particularly with respect to Duke-owned projects competing with third-party owned projects, noting the “complexities around how [the Solar Integration Charge is] implemented in the CPRE program” due to the need to ensure “that the Utility projects and the third- party projects are evaluated on an equal footing.” The Public Staff concluded that overall there are “a lot of discussions that still need to happen to ensure that that SISC is . . . considered appropriately in the context of the CPRE.”<sup>149</sup>

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<sup>148</sup> Tr. Vol. 3, p. 153.

<sup>149</sup> Tr. Vol. 7, p. 49.

It is important to note that in the context of CPRE, solar integration costs, like network upgrade costs, will be paid for by ratepayers in any case: either they will continue to be paid directly or they will be paid in the form of higher bid prices necessary to cover integration charges impose on market participants. The logical solution is therefore to treat any integration costs like network upgrade costs and have them be “socialized (i.e., paid by ratepayers) but attributed for projects for the purpose of determining whether their bid price is below the avoided cost cap. This approach eliminates the need for bidders to assume the worst-case scenario and inflate their bid prices, which would cause ratepayers to incur higher costs than if they simply absorb actual integration costs, which may be substantially less than the estimated “cap” on potential integration charges. This just underscores the need for this issue to be worked out in the CPRE docket with the involvement of the independent administrator (“IA”) and all interested parties.

As discussed above, it is also unclear how opportunities to avoid the charge through the addition of battery storage or the application of a dispatchable PPA would be applied in the context of Tranche 2. For context, it is worth recalling that the SISC Stipulation suggests multiple options for avoiding or mitigating the Solar Integration Charge, “through inclusion of energy storage devices, dispatchable contracts, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generator,” distinguishing between the inclusion of energy storage devices and “dispatchable contracts.”<sup>150</sup> In response to questions from the Commission during the evidentiary hearing regarding the urgency of developing an applicable “exit ramp” to the Solar Integration Charge for dispatchable solar generators, Duke witness Snider stated that the storage

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<sup>150</sup> *SISC Stipulation*, p. 5.

protocol would be the applicable document addressing potential mitigation of the Solar Integration Charge.<sup>151</sup> As described above, the details of the energy storage protocol and any other storage-related parameters that would allow a solar facility to avoid the Solar Integration Charge remain unsettled. Outside the context of energy storage, Duke also has not provided any additional information regarding whether and how the existing dispatch rights of the CPRE PPA, which allow uncompensated economic dispatch and curtailment for up to 5% of expected annual output for facilities in DEC and 10% in DEP,<sup>152</sup> may qualify a CPRE PPA as a “Dispatchable Contract.” It seems likely that Duke’s ability to curtail and dispatch CPRE projects as it chooses has the potential to reduce the ancillary services costs attributable to those projects, but there has been no analysis of that issue in either this or the CPRE docket. In other words, there is a significant likelihood that an application of the proposed Solar Integration Charge to Tranche 2 will impose excessive and unnecessary costs on ratepayers that could have been mitigated via the CPRE PPA’s existing dispatch rights. Even if final versions of these documents and guidelines were produced immediately, this would almost certainly not provide market participants adequate time to evaluate the requirements of those provisions and incorporate them into Tranche 2 bids prior to the opening of the bidding period.

For these reasons, even if the Commission ultimately approved a Solar Integration Charge, it would be impractical, infeasible, and inappropriate to incorporate a Solar

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<sup>151</sup> Tr. Vol. 3, p. 155.

<sup>152</sup> The CPRE Tranche 2 PPA provides that such dispatch rights may be utilized for any reason in the utility’s sole discretion and are not limited to system-wide curtailment events, as indicated in Section 1.26: “‘Control Instruction’ means any System Operator Instruction to dispatch, operate, and/or control the Facility in the same manner and/or for any reason as the System Operator may, in its sole discretion, dispatch, operate, and/or control Buyer’s own generating resources and power purchase arrangements used to provide service to Buyer’s native load customers.” See: *Renewable Power Purchase Agreement*. CPRE Tranche 2. Available at <https://accionpower.com>.

Integration Charge into Tranche 2. With respect to future CPRE tranches, NCSEA and NCCEBA submit that the Commission and interested parties would have additional time to more adequately consider these issues, including the applicability of any Solar Integration Charge and the availability other mechanisms or market tools to better capture both costs and benefits of integrating renewables onto the grid. While NCSEA and NCCEBA maintain that the Commission should reject the proposed Solar Integration Charge in this proceeding, NCSEA and NCCEBA would welcome the opportunity to engage in broader stakeholder discussions about the application of tools to incorporate greater levels of renewable energy generation in North Carolina.

Turning to GSA, as the Commission is aware, the avoided cost rate establishes the GSA Customer Bill Credit, and the available bill credit will directly impact the negotiated price between the GSA Customer and the GSA Supplier. As the Commission is also aware, the GSA Bill Credit is limited to the 5-year avoided cost rate, which will be lower than the 20-year rate available under the CPRE program. It is not at all clear how the integration charge would be applied to the GSA program, and significantly, in the over 18 months that have elapsed between Duke's initial filing of the GSA Program application and the Commission's final Order Approving Compliance Filing on August 5, 2019, NCSEA and NCCEBA are not aware of a single mention of the application of an integration charge to the GSA Program. Similar to the urgency surrounding Tranche 2, the GSA Program is scheduled to open in early October 2019, likely before the Commission has issued a final order in this proceeding. In any case, in order to prepare applications for submittal by the October 1 opening of the GSA program, potential GSA participating customers must already be engaged in negotiations with renewable suppliers which would be impossible

to consummate in the face of uncertainty about the possible application of a Solar Integration Charge. The same concerns regarding opportunities for solar facilities to qualify as “controlled solar generators” in the context of Tranche 2 also apply to the GSA program. It should also be noted that the GSA Program was developed at the same time that the Astrapé Study was developed, yet Duke failed to include the possibility of the integration charge in the GSA docket and did not explicitly announce in this docket the intention to include the integration charge against H.B. 589, including GSA, projects. This has resulted in a stipulation between the Public Staff and Duke where the parties do not even agree how the Solar Integration Charge will be applied.

For these reasons, even if the Commission approved a Solar Integration Charge in this proceeding, it would be inappropriate to apply the Solar Integration Charge to the GSA program.<sup>153</sup>

D. THE SOLAR INTEGRATION CHARGE STIPULATION VIOLATES PURPA BY NOT PROVIDING A STANDARD CONTRACT PPA TO QFs THAT ARE 100 kW OR LESS IN CAPACITY

The Commission should also reject the *Solar Integration Charge Stipulation* because it is contrary to the requirement of 18 C.F.R. § 304(c)(1), which directs that “There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.”

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<sup>153</sup> In addition, the Commission spent over a year considering and finally resolving the GSA bill credit issue and did so in a way that raised serious questions about the viability of the program. Three commissioners filed dissenting or concurring opinions based on concerns about the bill credit being potentially discouraging participation in the program. The addition of an integration charge, which is likely to further discourage participation, should not be considered without simultaneously reconsidering the bill credit structure and the combined impact of all these factors on program viability.

Neither Duke nor the Public Staff dispute that all solar plus storage QFs, regardless of size, would be required to enter into negotiated contracts under the *Solar Integration Charge Stipulation*. Duke Witness Snider testifies that “Section II.A of the SISC Stipulation provides that a ‘controlled solar generator’ that agrees in a negotiated PPA to materially reduce or eliminate the need for additional ancillary service requirements (as reasonably determined by the Companies), through inclusion of energy storage devices, dispatchable contracts, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generators, could avoid applicability of the Integration Services Charge.”<sup>154</sup> Similarly, Public Staff Witness Hinton testifies that “Section II.A of the SISC Stipulation specifically grants a QF that enters into a negotiated contract the ability to mitigate the SISC by demonstrating and contractually obligating itself to operate in a manner that materially reduces or eliminates the need for additional ancillary service requirements.”<sup>155</sup>

The fact that a solar plus storage QF would have the option of entering into a standard contract PPA that includes the Solar Integration Charge does not rectify the *Solar Integration Charge Stipulation*’s PURPA violations. The FERC explicitly stated that “The standard contract rates for purchase . . . May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different characteristics.”<sup>156</sup> However, the *Solar Integration Charge Stipulation* does not provide for differing standard contracts for solar QFs and solar plus storage QFs; it simply prohibits solar plus storage QFs that are 100 kW and smaller from receiving the full value of their

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<sup>154</sup> Tr. Vol. 2, p. 148.

<sup>155</sup> Tr. Vol. 6, p. 381.

<sup>156</sup> 18 C.F.R. § 292.304(c)(3).



energy and capacity, as well as their supply characteristics. As such, the *Solar Integration Charge Stipulation* should be rejected for violating PURPA and 18 C.F.R. § 304(c)(1).

### **VIII. THE COMMISSION SHOULD LOOK TO OTHER JURISDICTIONS FOR METHODS OF MORE EFFECTIVELY INTEGRATING RENEWABLE ENERGY**

As Duke Witness Snider notes, there is no dispute that distributed generation resources, in particular solar, are increasingly penetrating the grid: “[i]t is uncontroverted that [Duke has] experienced significant penetration of solar resources in recent years with significantly more solar resources to be interconnected in coming years.”<sup>157</sup> These solar additions have been the result of the PURPA market and also from statutes set forth at the North Carolina General Assembly, which have allowed for renewable generation, and solar in particular to flourish. However, such expansion and integration need to adhere to solutions that will allow the new generation mix to flourish on the grid based largely upon traditional generation sources. “[E]xpanded regional cooperation among utilities is a key to reducing integration costs and renewable curtailment, as the penetration of renewable wind and solar generation grows.”<sup>158</sup>

#### **A. DUKE’S ASTRAPÉ STUDY ASSUMED ECONOMIC INEFFICIENCIES AND FAILED TO CONSIDER POTENTIAL MARKET SOLUTIONS**

The proposed Solar Integration Charge is premised on the faulty intention to capture the ancillary service costs DEC and DEP allege it will take to operate their electric fleets, respectively. The Solar Integration Charge is supported by the Astrapé Study, which analyzed the incremental ancillary services costs to operate the DEC and DEP fleets to reliably integrate increasing penetrations of intermittent solar generation. Neither Duke,

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<sup>157</sup> Tr. Vol. 2, p. 125.

<sup>158</sup> *Beach Affidavit*, p. 19.

nor any other party, has explained sufficiently why setting an avoided cost rate requires that the Duke utilities be modeled as economic islands.

1. DUKE SHOULD BE REQUIRED TO LEVERAGE RESOURCES IN ITS OWN SERVICE TERRITORIES TO BETTER INTEGRATE RENEWABLES

According to Duke, it is required to have the Astrapé Study model its territories separately because NERC requires them to keep operating reserves at certain levels within their respective utility balancing areas.<sup>159</sup> NCSEA and NCCEBA do not contest NERC standards, but instead believes that Duke is missing a number of clear solutions or, at the very least, more cost effective mitigation options related to solar variability. One of those solutions or mitigations would be to allow a cost of solar study, and any resulting charges, to include the economic assumption that solar energy can be sent to the neighboring Duke service territories. While this does not reduce the NERC-required operating reserves necessarily, it would allow for Duke to utilize a model that accurately reflects the ability of the utility to transfer excess electricity to its sister service area which likely does not have the same high energy penetration issue. As noted by NCSEA Witness Beach, “[n]ot surprisingly, integration costs dropped by about 15% when the two [Duke] utilities were analyzed together.”<sup>160</sup>

On a broader level, while NCSEA and NCCEBA understand Duke’s solution to allegedly variable solar may be increased ancillary services including operating reserves to back up the solar, that method has not previously (to NCSEA’s and NCCEBA’s knowledge or as otherwise attested to in this docket) caused generation sources to incur charges. Furthermore, there are market-based solutions which will lower net costs incurred by Duke

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<sup>159</sup> Tr. Vol. 4, p. 4.

<sup>160</sup> Tr. Vol. 5, p. 124.

due to distributed generation. One of these solutions is sending excess electrons to other Duke Service territories and leveraging intercompany understanding of the needs across the Duke utilities' footprints.

2. DUKE SHOULD BE REQUIRED TO LOOK TO NEIGHBORING UTILITIES AND PJM FOR COST-EFFECTIVE OPTIONS

Similarly, Duke can also buy and sell generation on the wholesale market to other utilities, including specifically neighboring utilities and the regional transmission organization PJM Interconnection LLC ("PJM"). Again, NCSEA and NCCEBA are not advocating for Duke to ignore NERC (or any other) standards, but, instead, when modeling the costs associated with excess solar or solar generation dips in generation, a study must include a reasonable host of options to seek relief from outside the utilities' balancing area.

3. CAISO PROVIDES AN EXAMPLE OF SUCCESSFUL TOOLS FOR INTEGRATING RENEWABLES

As referenced above, CAISO is an area with an even higher amount of distributed solar generation in its generation mix. The CAISO statistics are stunning – since 2006, CAISO has seen its distributed generation mix grow its solar and wind generation sources by a factor of *nine*.<sup>161</sup> Further, while ancillary services costs in CAISO have fluctuated between 0.5% and 2.0% of CAISO energy market costs over that period, that fluctuation is reflective of the availability of large hydro resources and not solar variability.<sup>162</sup> Furthermore, the increases in CAISO for ancillary services costs incurred by the utility are fractional compared to the huge amounts of distributed wind and solar generation growth over that time period. The CAISO experience demonstrates that more solar does not

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<sup>161</sup> Tr. Vol. 5, p. 118.

<sup>162</sup> *Id.*

necessarily equal more costs associated with ancillary services costs. In addition, CAISO utilized techniques to incorporate large amounts of distributed solar and wind without reliability concerns or massive ancillary service cost increases by utilizing market mechanisms that are available to Duke and Dominion.

4. AN EIM SHOULD BE SERIOUSLY CONSIDERED IN THE EASTERN UNITED STATES

The EIM in the western United States has allowed for the trading of renewable energy throughout the established marketplace without violating any NERC reliability standards, or any standards at all for that matter. The EIM in the western United States has grown quickly since forming: “The western EIM began with an agreement in 2014 between just CAISO and PacifiCorp, but since then has spread across almost the entire Western Interconnection and now includes utilities in every state in the WECC except Colorado and Texas.”<sup>163</sup> Notably, the western EIM has “saved money for every participating utility” to a tune of \$650 million in savings as of the end of the first quart of 2019.<sup>164</sup> EIM is an overlay that does not change traditional processes and is run by its existing operator and can take advantage of a number of different market and regulatory structures.<sup>165</sup> As NCSEA Witness Tom Beach states, the EIM has been “found money” for western utilities who were looking to resolve inefficiencies in their intra-hour dispatch.<sup>166</sup>

Duke’s position on the EIM proposal appears to be that they aren’t required to, so they will not do it, and, furthermore, the avoided cost proceeding is not the appropriate

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<sup>163</sup> Tr. Vol. 5, p. 124.

<sup>164</sup> Tr. Vol. 5, p. 125.

<sup>165</sup> Tr. Vol. 5, p. 125.

<sup>166</sup> Tr. Vol. 5, p. 125.

venue to discuss this: “EIM fails to recognize the limited purpose of this biennial avoided cost proceeding.”<sup>167</sup> Duke further obfuscates the EIM proposal by saying this would not alleviate Duke’s need to incorporate ancillary services:

Market constructs establish rules and frameworks for promoting new investment and transacting for a needed commodity between willing buyers and sellers, here, ancillary services. However, Duke must still pay for the ancillary services, i.e., the "needed commodity," regardless of how it is procured. As explained by Duke Witness Wheeler, the Integration Services Charge assures that the costs of" these incremental ancillary services requirements are recovered from the solar generators who are the cost causers versus from retail customers.<sup>168</sup>

Again, Duke Witness Snider is missing the point. EIM provides a marketplace solution for solar penetration level variability. Whether a utility has too much energy, or not enough, the EIM market provides the ability to trade resources with neighboring utilities and RTOs in a way that will lower costs for ratepayers, as clearly evidenced in the western U.S. Furthermore, while the need for ancillary services, including operating reserves, may remain, it is uncontroverted by Duke that the EIM marketplace function could offset those “costs” associated with ramping up and down in response to solar variability concerns. Moreover, solar (and wind) generation provides the unique ability to produce generation above what is needed, or, in some cases, below what is needed, at any given time. Such variability should be accounted for in production cost modeling insofar as the marketplace outside your service territory may provide relief. For Astrapé and Duke

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<sup>167</sup> Tr. Vol. 2, p. 138.

<sup>168</sup> Tr. Vol. 2, p. 142.

to have done such modeling without any such projections is not indicative of relevant and necessary marketplace solutions available to and utilized by utilities.<sup>169</sup>

B. A COMPREHENSIVE STUDY ON THE VALUE OF SOLAR AND DISTRIBUTED GENERATION WITH STAKEHOLDER PARTICIPATION AND FEEDBACK WOULD STREAMLINE CURRENTLY LITIGATED ISSUES

As noted extensively here, there are a considerable number of inputs to the Astrapé Study which NCSEA, NCCEBA, and other intervenors believe were either omitted, incorrectly applied, or incorrectly included in the Astrapé Study. This could have been solved with a collaborative process, with Commission oversight, which would provide a “value of solar” data point that would be useful both in this docket and all other related dockets. There is simply no reason to repeat the process of allowing the Utilities to hire a consultant to build a model, which is presented as a completed product, often cloaking the inputs, and then having the stakeholders attempt to pore over the product for issues. Having the Utilities work alongside the stakeholders to reach determinations about inputs would relieve some of the issues that have resulted in such an extensive and heavily litigated avoided cost docket, along with other dockets. North Carolina has considerable distributed generation resources, notably solar, and it is important that the stakeholders have a common understanding of the prevailing “value” propositions at play. This includes incorporation of resource planning, finding the value of solar at a generation level, transmission level, and distribution level, and an incorporation of factors such as the Clean Energy Plan. NCSEA and NCCEBA believe that the Solar Integration Charge should be rejected, but, if the Commission truly believes that distributed solar does incur costs on the grid paid by

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<sup>169</sup> Clearly, Duke Energy recognizes the need to purchase from other generation sources outside its services territories; Duke makes substantial investments in renewable energy generation outside the DEC and DEP territories and wheels some of that power to DEC and DEP. See, <https://news.duke-energy.com>.

ratepayers who are not receiving benefits, then NCSEA and NCCEBA believe that a structured stakeholder process will allow us to begin to solve that problem in a meaningful way.

**IX. THERE IS NO NEED TO ADOPT INTEGRATION CHARGES AT THIS TIME**

The foregoing discussion demonstrates the many substantive and procedural problems with Duke's proposed Solar Integration Charge and the many benefits that could result from considering this issue in a more deliberative and inclusive manner. NCSEA and NCCEBA submit that, especially in light of those concerns, there is no reason for the Commission to approve a Solar Integration Charge in this proceeding at this time. As discussed above, such a charge is not appropriate at this time with respect to CPRE Tranche 2 and GSA, but, in any case, should be considered in those dockets, not here. With respect to PURPA, there are no existing PPAs scheduled expire in the current biennium and no indication that any significant number of new QFs will seek to enter into PPAs during that period. NCSEA and NCCEBA therefore urge to Commission to defer action on a Solar Integration Charge until the next biennial avoided cost proceeding to allow the many concerns identified herein to be properly addressed.

**X. STANDARD PPA TERMS AND CONDITIONS**

**A. DUKE'S ATTEMPT TO REWRITE EXISTING PPAS AFTER THE FACT SHOULD BE REJECTED AND MANY OF ITS PROPOSED MODIFICATIONS TO THE FORM STANDARD OFFER PPA AND TERMS AND CONDITIONS SHOULD BE MODIFIED OR REJECTED**

In this proceeding, Duke is proposing significant modifications to its standard offer PPA and Terms and Conditions. As discussed below, and as reflected in the limited redline

changes to Duke's documents set forth in **Exhibit 1**,<sup>170</sup> many of Duke's proposed modifications are acceptable to NCSEA and NCCEBA, while some of those modifications are problematic and unacceptable. What is an even bigger problem, however, is Duke's unlawful attempt in this proceeding to make major modifications to the rights and obligations of the parties to existing standard offer PPAs, under the guise of "clarifying" what those contracts mean.<sup>171</sup>

Duke has sought to accomplish this objective first by simply announcing that it is going to interpret existing contracts how it chooses, without regard to what the terms of those contracts actually say.<sup>172</sup> Specifically, the *Duke Initial Statement* unilaterally announces that any increase to

[a QF's] "Contract Capacity"<sup>173</sup> under the current Schedule PP PPA and Section 4 of the Terms and Conditions will not be allowed if the QF seeks to retain its pre-existing standard offer PPA at the Companies' stale and significantly higher avoided cost rates. Any such action by the QF would constitute a modification to the QF "Facility" that has committed to sell power to DEC or DEP under the then-effective PPA and an event of default resulting in termination of the PPA, at the Companies' election. . . . Any unilateral attempt to further modify the PPA, including a material

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<sup>170</sup> Exhibit 1 consists of NCSEA and NCCEBA's suggested edits to both Duke's proposed PPA and its proposed Terms and Conditions. Since those documents are virtually identical for DEC and DEP, NCSEA and NCCEBA have only marked up the DEC documents.

<sup>171</sup> The Companies' stated reason for both its interpretation of existing PPAs and its proposed prospective changes is to prevent QFs from increasing their output and revenues at prior avoided cost rates that may overcompensate QFs relative to current avoided costs. *Duke Initial Statement* at 35-36; *Duke Reply Comments* at 131-37; *Snider Direct* at 43-46. As pointed out by NCSEA Witness Norris, the Companies express no concern about recovering from ratepayers capital and operating costs of their own facilities that may exceed current avoided costs. *See, Norris Responsive* at 22-23.

<sup>172</sup> Duke has not asked the Commission to modify those contracts after the fact. It is doubtful that the Commission has the authority to do so under state or federal law; in any case such retroactive contract modification is extremely ill-advised and dangerous public policy. *See, Sub 148 Order* at 18 (in which the Commission recognized the need to "avoid introducing regulatory uncertainty" through retroactive policy changes).

<sup>173</sup> In the preceding sentence, Duke suggests that "Contract Capacity" in existing PPAs include both "AC capacity" and "DC (energy) output, even though, as discussed below, that is clearly not the case. In addition, Duke's "DC (energy) output" construction confirms, as argued below, that a limit on DC capacity and on annual energy production serve the same purpose and are redundant of each other.



modification of the design, description or capability of the “Facility” would constitute a breach of contract against the party attempting the modification, giving rise to a termination right.<sup>174</sup>

These claims about what Duke will “allow” are not justified by any citation to the actual language of the relevant PPAs or Terms and Conditions.

Duke then disingenuously claims that the extensive modifications proposed in this proceeding to its prior standard offer PPA and Terms and Conditions are just “clarifying” in nature and do not actually alter the rights and obligations of the parties under those agreements.<sup>175</sup> However, as Commissioner Clodfelter pointed out during the evidentiary hearing<sup>176</sup> the meaning and effect of existing PPAs turns on the plain language of those documents (or an interpretation of any ambiguity by this Commission or the courts) – not on a unilateral fiat by Duke. As discussed in detail below, a careful reading of those documents contradicts Duke’s interpretation and claim that its modifications are merely clarifying in nature.

B. PRIOR DUKE STANDARD OFFER PPAS DO NOT CONTAIN A LIMIT ON DC CAPACITY OR ANNUAL ENERGY OUTPUT AND DO NOT PROHIBIT OR REQUIRE DUKE’S APPROVAL FOR MODIFICATIONS TO THE QF FACILITY OR SHIFTING THE TIME OF ENERGY DELIVERY

NCSEA and NCCEBA have carefully reviewed the Duke standard offer PPA documents approved by the Commission in the E-100, Sub 136 and E-100, Sub 140 proceedings, under which the majority of Duke QF PPAs have been executed. The results of that review are presented below. To the extent that Duke contends that any other versions

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<sup>174</sup> *Duke Initial Statement*, p. 35.

<sup>175</sup> *See Duke Initial Statement* at 36; *Duke Reply Comments* at 133-34; Tr. Vol. 2, pp. 397-98; Tr. Vol. 3, pp. 151-52.

<sup>176</sup> *See Tr. Vol. 3*, pp. 147-53.

of the PPA documents call for a different result, the burden should be on it to make that case.

The DEC Sub 136 Standard Offer Purchased Power Agreement, filed with the Commission on March 13, 2014, is a 12-page form document, pages 8 through 11 of which are the DEC Sub 136 Standard Offer Tariff for Non-Hydroelectric Qualifying Facilities (Schedule PP-N(NC), Electricity No. 4, North Carolina Twelfth Revised Leaf No. 91) (the “DEC Sub 136 PPA”). Nowhere in the DEC Sub 136 PPA is there any mention of increases in DC capacity, changes in facility equipment, increases in energy output, or shifting in the time of day of delivery – let alone a prohibition of such actions by Seller or a requirement of Dec’s consent to such actions. Indeed, the DEC Sub 136 PPA includes no mention of quantity or timing of energy output whatsoever, except a limitation on the amount electric power that can be delivered under the PPA (implicitly on an instantaneous basis) to the Nameplate Capacity of the Facility. DEC Sub 136 PPA § 1.4(c). On the contrary, it simply provides that DEC must “purchase, receive, use, and pay for [all of the electric power generated by the Facility].”<sup>177</sup>

The DEP Sub 136 Standard Offer Purchase Agreement is more complicated, in that it consists of three documents: (1) the Company's form of “Application for Standard Contract by a Qualifying Cogenerator or Small Power Producer” when signed by Seller and accepted by Company (the “DEP Sub 136 Application”); (2) the applicable Schedule and Riders, specifically “Cogeneration and Small Power Producer Schedule CSP-29” (“Schedule CSP-29”); and (3) the Company’s nine-page standard “Terms and Conditions for the Purchase of Electric Power” (the “DEP Sub 136 Terms and Conditions”), all of

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<sup>177</sup> *Id.* § 1.1.

which were filed with the Commission on March 13, 2014. *See* DEP Sub 136 Terms and Conditions § 1(a) (stating that the three documents comprise the Purchase Agreement).

Paragraph 2 of the DEP Sub 136 Application sets forth the “maximum generation capacity” (regularly expressed in kW AC) and the “estimated annual energy production” of the contracting facility – information that is provided by the applicant by filling in blanks in the form agreement. Section 4 of the DEP Sub 136 Terms and Conditions, entitled “Contract Capacity” and page 2 of Schedule CSP-29 (under the same heading) establish the maximum capacity value stated in paragraph 2 of the DEP Sub 136 Application as the “Contract Capacity.” Although the DEP Sub 136 Terms and Conditions clearly contemplate that such value can be modified if the DEP system can accommodate a capacity addition, Schedule CSP-29 does clearly state that any capacity in excess of the Contract Capacity must be absorbed by the Facility (*i.e.*, that the Contract Capacity value may not be exceeded).

In contrast, neither the Sub 136 Terms and Conditions nor Schedule CSP-29 make any reference to the estimated annual energy production figure set forth in paragraph 2 of the DEP Sub 136 Application. On the contrary, Section 5 of the DEP Sub 136 Terms and Conditions introduces a new concept of “Contract Energy,” which is not an estimate at all but is instead the actual largest measured amount of energy delivered by the Facility, both during on-peak and off-peak periods, during any continuous 12-month period during the first 24 months of operation. While this could suggest that this “Contract Energy” value could not be exceeded after the first 24 months of the PPA term, none of the documents comprising the Purchase Agreement make any reference to this defined term of “Contract Energy” or state that it may not be exceeded. If Duke (or the Commission) intended for

either the estimated annual energy production value in the Sub 136 Application or the Contract Energy value in the Sub 136 Terms and Conditions to constitute a maximum annual energy production level that cannot be exceeded, it could have easily so stated in plain English. In the absence of such an explicit and unambiguous prohibition, the PPA should be construed against Duke as the drafter as not containing such a provision.

Nor do the documents make any reference to, or in any way prohibit or require DEP's consent for modifications to the Facility's DC rating, equipment modifications, or shifts in the time of delivery. Though if the Contract Energy values were deemed to be caps on energy delivery (which NCSEA and NCCEBA contend is not the case), the fact that they are computed separately for on-peak and off-peak periods would place some limit on time-shifting.<sup>178</sup>

The situation is less complex with respect to Sub 140 PPAs, because DEC and DEP migrated to uniform contract documents consisting of a three-page form "Purchase Power Agreement by a Qualifying Cogenerator or Small Power Producer" (the "Sub 140 PPA"), filed with the Commission on February 2, 2016, which incorporates by reference the Rate Schedules and "Terms and Conditions for the Purchase of Electric Power" (the "Sub 140 Terms and Conditions") on file with the Commission.<sup>179</sup>

Section 1.4 of the Sub 140 PPA contains blanks for inserting the "Contract Capacity" and the "estimated annual energy production," which is described as "the amount Seller contracts to deliver to Company and Company agrees to receive." While that

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<sup>178</sup> Duke Witness Johnson has acknowledged that the Duke tariffs and PPAs do not expressly prohibit time-shifting, but then make a weak and unconvincing argument that they should nonetheless be read to include such a prohibition. *Joint Supplemental Rebuttal* at 30-31. This is another example of Duke arguing that it should not be held to the plain terms of contracts that it drafted and that this Commission should instead interpret those contracts to mean what Duke wishes they said.

<sup>179</sup> In the case of DEC, the applicable schedule is Rate Schedule PP, Electricity No. 4, North Carolina 5<sup>th</sup> Revised Leaf No. 90. In the case of DEP, the applicable schedule is Purchased Power Schedule PP-1.

language could in theory be read to suggest that the estimated annual production value represents both a minimum and maximum energy production amount, that is implausible for several reasons. First, it is described as an “estimate,” not a guaranteed minimum or an absolute cap. An estimate by its very nature is an imprecise value not suitable for use as definite constraint. Second, it is well known that the output of solar energy facilities varies from year to year based on insolation and declines gradually over time, so the idea of single annual delivered value that may not fluctuate in either direction is non-sensical. There is nothing in the Sub 140 PPA that deals in any way with DC rating, equipment modifications, or time-shifting of delivery.

Nor is there anything in either company’s Rate Schedule that has any bearing on DC rating, equipment modification, or changes in the quantity and timing of delivered energy. In fact, in the Sub 140 Rate Schedule Duke deleted (with the Commission’s approval) the sentence in Schedule CSP-29 (discussed above) limiting delivered capacity to the Contract Capacity.

The Sub 140 Terms and Conditions are based heavily on the DEP Sub 136 Terms and Conditions, but with significant modifications. Of particular note, Section 4(b) of the Sub 140 Terms and Conditions was modified to provide that “[t]he Seller shall not change its generating capacity or contracted estimated annual kWh energy production without adequate notice to the Company, and without receiving the Company’s consent.”<sup>180</sup> For the reasons discussed above, an estimate cannot function as a cap. Moreover, this sentence does not require the Company’s consent for an *exceedance* of the estimated annual energy

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<sup>180</sup> The immediately following clause suggests that the concern underlying this restriction is loss or damage to the company’s facilities, and that the applicable remedy for such a breach is Seller liability for any such loss or damage.

production, which as discussed above, could be routinely expected to occur (as could a failure to meet the estimated annual production). Rather, it requires consent for a *change* to that estimate. But neither the Sub 140 PPA nor Sub 140 Terms and Conditions specify the circumstances under which the QF must make a change to its estimate. Again, Duke should be held to the standard of drafting unambiguous contracts that say what they mean. In addition, the ambiguity around energy delivery reflected in the Sub 140 PPA, discussed above, is not resolved, and is arguably exacerbated, by the confusing language of Section 5 of the Sub 140 Terms and Conditions, entitled “Contract Energy,” which reads:

The Contract Energy specified in the Purchase Power Agreement shall be the estimated total annual kilowatt-hours registered or computed by or from the Company's metering facilities for each time period during a continuous 12-month interval.

It is hard to know what this sentence means, but one thing is certain – the contract documents do not contain an express prohibition on exceeding this “Contract Energy” value.

The Sub 140 Terms and Conditions do not prohibit or require DEC/DEP approval of changes to the Facility’s DC rating, changes in the time of delivery,<sup>181</sup> or equipment modifications. With respect to the latter, Section 8(e) of the Sub 140 Terms and Conditions states as follows:

The Seller shall provide the Company written notification of any changes to their generation system, support equipment such as inverters, or interconnection facilities and shall provide the Company adequate time to review such changes to ensure continued safe interconnection prior to implementation.

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<sup>181</sup> Duke Witness Johnson acknowledges that the prior PPAs do not expressly prohibit time-shifting, but that remarkably asserts that the such a prohibition is intended by the agreements. See *Joint Supplemental Rebuttal* at 31. The only provision he points to in support of that assertion is Section 4(b) of the Terms and Conditions, quoted above. Needless to say, an estimate of a Facility’s total annual energy production says absolutely nothing about when that energy will be delivered.

Thus the only limitation on such modifications is that they not adversely affect “safe interconnection.”

In sum, the documents that comprise the Sub 136 and Sub 140 PPAs do not, under any reasonable interpretation, impose the limitations on QFs that Duke is now asking the Commission to make to its form PPA and Terms and Conditions going forward. The modifications Duke is proposing constitute major substantive changes to the rights and obligations of Duke and QFs relative to the terms of prior standard offer contract documents. The Commission should reject Duke’s unsubstantiated attempt to characterize these major changes as clarifying in nature and to impose these new and altered terms on QFs retroactively.

Although not directly relevant to the interpretation of Duke’s standard offer tariff, it is also worth noting that there is nothing in Duke’s previously used negotiated PPAs that prohibits equipment changes, changes to the facility’s production profile, or annual energy production in excess of estimates. The negotiated PPA does make it an event of default to exceed stated AC Nameplate Capacity, which supports the argument that other changes not called out as events of default are permitted. Exhibit 4 to the negotiated PPA, which briefly describes some of the basic Facility equipment, is labeled “Facility Information.” Contrary to Duke Witness Johnson’s assertion that this informational exhibit contains material terms of the agreement that may not be modified,<sup>182</sup> there is nothing in the PPA, including in the enumerated events of default, that in any way suggests that modifications to the information contained in Exhibit 4 are prohibited or require Duke’s consent.<sup>183</sup> The

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<sup>182</sup> *Joint Supplemental Rebuttal* at 31-32.

<sup>183</sup> Duke Witness Johnson acknowledged this fact with respect to certain “old” negotiated PPAs, but stated that such a prohibition has been included in “new agreements.” Tr. Vol. 3, p. 9.

Estimates of Annual Energy Production are used solely for the purpose of establishing *minimum* output requirements pursuant to Section 8.5 of the PPAs. If it was Duke's intent to prohibit modifications or limit annual energy production in these detailed agreements running more than 40 single-spaced pages, it could easily have said so in plain English.

C. PRIOR DOMINION STANDARD OFFER PPAS ALSO DO NOT CONTAIN A LIMIT ON DC CAPACITY OR ANNUAL ENERGY OUTPUT AND DO NOT PROHIBIT OR REQUIRE DOMINION'S APPROVAL FOR MODIFICATIONS TO THE QF FACILITY OR SHIFTING THE TIME OF ENERGY DELIVERY

Dominion has not sought in this proceeding to modify its standard offer contract documents and did not assert in its initial statement, its reply comments, or its initial direct testimony that its current or prior contract documents prohibit equipment modifications, including the addition of battery storage, increases in energy production, or time shifting. However, in response to the Commission's request for supplemental testimony regarding storage additions, Dominion Witness Billingsley asserted that the addition of storage to QFs that have formed LEOs, executed standard offer PPAs or are in operation is prohibited, as well as increases in energy production and time-shifting of energy output.<sup>184</sup> This assertion is surprising given that Witness Billingsley acknowledges that Dominion's prior standard offer tariffs and PPAs do not specifically address the issue of storage addition.<sup>185</sup> Indeed, a careful review of Dominion Sub 136 and Sub 140 standard offer tariffs and PPAs reveals that none of those documents in any way supports Witness Billingsley's position.

Dominion's Sub 136 standard offer PPA is a 19-page document entitled "Agreement for the Sale of Electrical Output to Virginia Electric and Power Company," filed with the Commission on March 13, 2014. Dominion's Sub 140 standard offer PPA is

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<sup>184</sup> See *Billingsley Supplemental* at 2-3.

<sup>185</sup> *Billingsley Supplemental* at 2.



a 17-page document with the same title, filed with the Commission on February 2, 2016. The two PPAs are substantially identical and contain substantive terms in the body of the agreement and in an Exhibit B labeled “General Terms and Conditions.” The PPAs contain detailed commercial terms on many issues, including a maximum AC capacity value referred to as the “Contracted Capacity” (Article 3), an enumeration of events of default which allow termination of the PPA by the Company (Article 8 in the Sub 136 PPA and Article 7 in the Sub 140 PPA), and representations and warranties by the QF (Article 9 in the Sub 136 PPA and Article 8 in the Sub 140). However, there is not one word in either PPA (or tariff) that remotely prohibits or requires the Company’s approval for (i) increases in DC rating, (ii) increases in annual energy production above a defined amount, (iii) equipment modifications, including the addition of battery storage, or (iv) shifting in the time of energy delivery. In fact, none of these subjects are even mentioned.

Witness Billingsley offers no legal explanation as to why Dominion’s existing contracts should be interpreted to mean something other than what they say and to materially alter the rights and obligations of the parties under those agreements. Rather, like Duke, he relies primarily on the argument that such rewriting of the agreements would protect ratepayers from having to pay for additional generation at outdated rates. Needless to say, the law does not allow the rewriting of contracts just because one party does not like its terms. That’s all the more the case where that party unilaterally drafted the contract terms.

Witness Billingsley does attempt, unconvincingly, to argue that modifications to facility equipment or output should not be allowed to the extent that those matters were addressed in the Facility’s Form 556 or CPCN, both of which are exhibits to the PPAs.

However, the facility information contained in those filings is routinely subject to change. More importantly, as noted, nothing in the PPAs prohibits or requires company approval for modifications to those documents or to the underlying facility characteristics that may be described in them.

In sum, Dominion's Sub 136 and Sub 140 PPAs in no way limit storage additions or the other types of facility modifications discussed above.<sup>186</sup>

D. DESPITE THE UTILITIES NOT HAVING THE RIGHT TO PROHIBIT STORAGE ADDITIONS, INCREASES IN ANNUAL ENERGY PRODUCTION, OR TIME-SHIFTING UNDER PRIOR STANDARD OFFER PPAs, NCSEA AND NCCEBA HAVE PROPOSED A REASONABLE COMPROMISE TO PROTECT RATEPAYER INTERESTS

In the interest of achieving an amicable resolution of the dispute regarding QF rights under existing PPAs, NCSEA, with the support of NCCEBA, has proposed a compromise under which QFs would relinquish a portion of the rights they have under those agreements. NCSEA proposes that the output of storage additions to committed QFs (*i.e.*, those with enforceable LEOs or executed PPAs) be compensated at the avoided cost rate in effect when the QF's interconnection agreement is amended to include the storage addition.<sup>187</sup> <sup>188</sup> An essential element of this compromise proposal is that the new avoided cost rate for the storage addition be calculated and available for the remaining life of the QF's current PPA<sup>189</sup> and that the PPA price paid for the rest of the output of the Facility be

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<sup>186</sup> NCSEA and NCCEBA have not reviewed other Dominion standard offer PPAs but believe that they are no different in this regard.

<sup>187</sup> NCSEA and NCCEBA have not previously specified the point in time at which the avoided cost rate would be calculated under their compromise proposal, but are providing this here for the first time.

<sup>188</sup> See *Norris Supplemental* at 27-30.

<sup>189</sup> Duke's claim that allowing output from storage additions to be compensated at current avoided cost rates for the remaining life of the PPA is inconsistent with H.B. 589, see *Joint Supplemental Rebuttal* at 16-17, is misplaced. H.B. 589 in no way addressed the rights of QFs under existing PPAs and has no bearing on the potential negotiated resolution of a dispute regarding the rights of the parties under those agreements.

unaffected. This proposal is very similar to one made by the Public Staff.<sup>190</sup> <sup>191</sup> Duke opposes this compromise proposal for a variety of reasons, the leading one being its erroneous insistence that existing PPAs do not allow storage additions.<sup>192</sup>

NCSEA and NCCEBA agree with Ecoplexus Witness Wallace that it is technically feasible to separately meter storage additions to solar facilities.<sup>193</sup> Public Staff Witness Metz also testified that this approach may be feasible,<sup>194</sup> while recognizing that there may be some challenges and identifying an alternative administrative approach under which any increased energy output following a storage addition would be compared to a baseline value, with the increased production being compensated at the current rate.<sup>195</sup> However, if as Witnesses Metz, Wallace and Wheeler suggest,<sup>196</sup> the complexity of this issue calls for a stakeholder process to further explore feasibility and implementation details, NCSEA and NCCEBA are prepared to participate in such a process but, given their position that storage additions are not currently prohibited, would not support a limitation on such additions in the interim.

E. MANY OF DUKE’S PROPOSED MODIFICATIONS TO THE FORM PPA AND TERMS AND CONDITIONS ARE PROBLEMATIC AND SHOULD BE MODIFIED OR REJECTED

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<sup>190</sup> See *Public Staff Initial Comments* at 75-76; *Metz Supplemental* at 5.

<sup>191</sup> However, NCSEA and NCCEBA are not proposing a modified PPA rate for any increases in energy production due to increases in DC rating, such as through re-paneling or overpaneling.

<sup>192</sup> See *Duke Reply Comments* at 141-48.

<sup>193</sup> See *Wallace Supplemental* at 5-9.

<sup>194</sup> See *Metz Supplemental* at 15 (“Based on my experience as a system designer and integrator as well as some preliminary research, there are multiple possibilities to measure output of co-located batteries (equivalent to two energy sources being dual monitored).”).

<sup>195</sup> See *Metz Supplemental* at 17-19.

<sup>196</sup> see *Metz Supplemental* at 19-20; *Wallace Supplemental* at 9; *Joint Supplemental Rebuttal* at 29.

As noted above, the Duke Utilities seek to make extensive changes to their form Standard Offer “Purchase Power Agreement by a Qualifying Cogenerator or Small Power Producer” (the “Sub 158 PPA”) and “Terms and Conditions for the Purchase of Electric Power” (the “Sub 158 Terms and Conditions”).<sup>197</sup> The majority of these changes seek: (1) to redefine the “Nameplate Capacity” of the Facility to include its DC rating (as well as AC capacity); (2) to create a new defined term (“Existing Capacity”) equal to the Facility’s “estimated annual energy production” stated in the PPA; and (3) to prohibit a “Material Alteration” to the Facility without Duke’s consent, with “Material Alteration” defined to include (a) the addition of a Storage Resource, (b) an increase in the AC capacity or DC rating of the Facility, (c) an increase to the Existing Capacity of the Facility,<sup>198</sup> or (d) a decrease in Existing Capacity by more than 5%. These changes would, in effect, require any QF seeking to either modify its Contract Capacity or Nameplate Capacity (including its DC rating), increase its annual energy production above an estimated value, or add storage to terminate its existing PPA and enter into a new PPA at current avoided cost rates.

NCSEA and NCCEBA do not object to Duke’s proposed terms that clearly provide that a Facility’s AC Contract Capacity may not be modified without the Company’s consent (Sub 158 Terms and Conditions § 1(i)) or exceeded without an amendment to the PPA (*id.* § 4(a)). In fact, Duke has proposed some helpful changes to the terms and conditions dealing with Contract Capacity that eliminate ambiguity on this issue contained

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<sup>197</sup> See, *Duke Initial Statement*, pp. 34-38, DEC Exhibits 3 and 4, and DEP Exhibits 3 and 4; *Duke Reply Comments*, pp. 131-151 and Exhibits 4-6; *Snider Direct* at 42-47; *Duke Witness Johnson Direct* at 4-9; and *Duke Witness Johnson Rebuttal* at 3-6.

<sup>198</sup> As originally presented by Duke, the definition of “Material Alteration” could have been read to allow an increase of 5% or less to Existing Capacity due to the like-kind repair or replacement of equipment, but the Public Staff has proposed, and Duke has accepted, a repunctuation of the definition that eliminates that reading. See *Metz Supplemental* at 11 and fn. 22; *Duke Joint Supplemental Rebuttal* at 32-33.

in prior versions of the Terms and Conditions. However, there is no basis for prohibiting changes in a Facility's DC rating and thereby limiting efficiency improvements to the Facility.<sup>199</sup> The sole reason for such a limitation would be to prevent the QF from increasing its energy output at a given AC capacity and thereby increasing output at older avoided cost rates. That goal can be fully accomplished by a clear maximum annual energy production value that may not be exceeded without a PPA amendment or the Company's consent, which, as discussed below, NCSEA and NCCEBA do not oppose.<sup>200</sup>

NCSEA and NCCEBA believe that Duke's proposed limitation on changes to a Facility's DC rating should be deleted in its entirety. However, if the Commission decides to adopt this change it should be modified in two respects. First, a reduction in DC capacity, which could be necessary if the Facility footprint has to be downsized during the development process, has no bearing on the concerns expressed by Duke and should not be prohibited or require the Company's consent. Second, some increase in a solar facility's DC rating (not affecting its AC capacity) may occur during the development process or as a result of equipment replacement over time. To address this fact, any limitation on DC rating should be expressed as a maximum DC:AC ratio of 1.5 (to allow for improvements to currently prevailing standards).<sup>201</sup> As long as this allowance is defined and known in advance, and is coupled with a maximum annual energy production limit, it in no way undermines the goal Duke seeks to advance.

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<sup>199</sup> The DC module array nameplate rating of utility-scale solar facilities is typically sized larger than the AC capacity in order to generate as close to the facility's full AC rating for more hours during the day, thus increasing the system's capacity factor and making its output more reliable.

<sup>200</sup> It should also be noted that under PURPA DC rating is irrelevant to eligibility thresholds based on Facility capacity.

<sup>201</sup> The average DC to AC ratio of U.S. utility-scale solar facilities reached 1.32 in 2017. Lawrence Berkeley National Laboratory, "Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States – 2018 Edition" (2018), available at <https://emp.lbl.gov>.

As noted, NCSEA and NCCEBA support the inclusion of a maximum annual energy production value in the Sub 158 PPA and Terms and Conditions, but there are several serious problems with the way in which Duke seeks to accomplish this objective. First, any maximum, not-to-be-exceeded level of annual energy production should be stated as just that – a maximum, not an estimate. As discussed above with respect to the past PPA documents, an estimate is by definition an imprecise value that cannot serve as bright-line standard for contractual compliance. This is particularly true since the production of solar facilities varies from year to year with changes in weather and insolation and typically declines over time as panel efficiency degrades.

Duke has not explained how a maximum (or estimated) annual energy production value would or should be determined. It is NCSEA and NCCEBA’s understanding that in the past (i) the QF has simply filled in the blanks in Paragraph 1.4 of the form PPA, and (ii) Duke has not typically questioned or sought to enforce those values.<sup>202</sup> However, in the interest of clarity, and in furtherance of Duke’s goal to limit the ability of the QF to make unlimited increases in its energy production, NCSEA and NCCEBA recommend that the contract documents include a bright-line value that allows for a modest increase in production over a reasonable baseline. Specifically, NCSEA and NCCEBA recommend that the maximum annual energy production be calculated as follows:

$$[\text{Nameplate Capacity}(AC) \times 8760 \times .30] \times 1.10$$

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<sup>202</sup> Duke Witness Johnson acknowledged that the Company does not “have a process in place to . . . continuously monitor a Facility’s annual energy production relative to the estimated value in the PPA. He did suggest, subject to check, that the Company makes some preliminary reasonableness estimate of the estimated annual energy production value. *See* Tr. Vol. 3, pp. 135-37. NCSEA and NCCEBA are not aware of either of these things having occurred.

This would provide QFs with a reasonable amount of operating flexibility but not unlimited ability to increase their output at existing PPA rates.<sup>203</sup>

Duke's proposed wording would also have the effect of prohibiting more than a 5% reduction in annual energy production. This has nothing to do with Duke's stated objective of ensuring that it not be required to purchase additional energy at stale rates and departs from Duke's and the Commission's long-standing position of not imposing a minimum annual energy production value in standard offer PPAs. This element of the proposed definition of "Material Alteration" should be deleted.

In addition, Duke's attempt in various ways to prohibit the addition of Storage Resources and other modifications to the Facility after PPA execution is both inappropriate and unnecessary. As previously discussed, a maximum annual energy production value limit accomplishes the objective of limiting increased output above that level. Any concerns about technical or operational impacts of equipment modifications are appropriately addressed under the Commission's Interconnection Procedures and the parties' interconnection agreement. This issue has been and continues to be the subject to extensive review and negotiation in the interconnection docket and whatever resolution is achieved there should resolve the issue, without the creation of a separate process under the PPA. The only other consideration is whether there is any basis for precluding time-shifting without the Company's consent, but the Duke witnesses have insisted that it and its ratepayers are indifferent as to when QF energy is delivered. (NCSEA and NCCEBA disagree with this position and contend that there are substantial benefits to increase

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<sup>203</sup> This approach, which significantly but not absolutely limits the QF's ability to increase annual energy production, is fully consistent with concerns that the Commission has expressed in the E-100 Sub 148 proceeding and elsewhere about stale avoided cost rates. Duke's proposal to allow zero increase above an estimated annual energy production value is unreasonable and impractical.

delivery on-peak, which is all the more reason that Duke should not be able to block storage additions that facilitate time-shifting.)

It should also be noted that making it more difficult for QFs to add storage resources or operate their facilities more efficiently is bad public policy. Such resources offer numerous benefits, including the potential to mitigate the impacts of solar intermittency and to allow energy to be delivered when it is most needed.<sup>204</sup> Accordingly, the addition of such resources when economically feasible should be encouraged rather than discouraged. As discussed, a reasonable maximum annual energy production value that would apply notwithstanding the addition of a Storage Resource or other equipment modifications is the most efficient and reasonable way to protect ratepayers from stale rates.

As discussed above with respect to in-service facilities, NCSEA and NCCEBA agree that all energy delivered from a Storage Resource added after PPA execution should be compensated at the avoided cost rate in effect at the time addition of the Storage Resource is approved.

Duke also seeks to prohibit the addition of Storage Resources to QFs between the time of LEO formation and PPA execution if the Storage Resource was not identified in the QFs CPCN application.<sup>205206</sup> For the same reason they oppose a prohibition on the addition of Storage Resource post-PPA, NCSEA and NCCEBA oppose such a prohibition post-LEO. However, NCSEA and NCCEBA would support the same limitations on Facility modification post-LEO as they support post-PPA – i.e., (i) no modification or

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<sup>204</sup> See *Norris Responsive* at 6-12.

<sup>205</sup> It is unclear whether Duke takes the same position with respect to any or all other modification to the Facility relative to the CPCN description.

<sup>206</sup> See *Snider Supplemental* at 5-11; *Duke Initial Statement* at 37-38.



exceedance of AC capacity without the Company's consent, and (ii) no exceedance of a reasonable maximum annual energy production value. These limitations should be included in the Notice of Commitment to Sell form.<sup>207</sup>

Finally, Duke has proposed a new Energy Storage Protocol as Exhibit A to its form Standard Offer PPA. While NCSEA and NCCEBA do not object to the inclusion of such a protocol (subject to approval by the Commission), the merits of Duke's proposed protocol have not been addressed in this proceeding. On the other hand, a similar proposed protocol has been the subject of detailed discussions among stakeholders in connection with the CPRE PPA, which discussions are ongoing. NCSEA and NCCEBA request that the Commission not approve an energy storage protocol for the standard offer program until the issue has been resolved under CPRE and the Commission can consider the results of those negotiations. In addition, contrary to what Duke has proposed, any future changes to the Energy Storage Protocol should be subject to Commission approval.

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## **XI. DUKE'S IRP ASSUMPTIONS REGARDING EXPIRING WHOLESALE CONTRACTS**

The vast majority of solar energy QFs in North Carolina have existing PPAs with Duke or Dominion under prior standard offer contracts vintages. Most of these contracts are fifteen-year PPAs that were entered into after 2007 and many within the past 6-7 years.

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<sup>207</sup> Duke mistakenly argues that because an element of the North Carolina LEO standard is a CPCN, the application for which requires a QF to identify the "gross and net projected maximum dependable capacity of the facility as well as the facility's nameplate capacity" and "projected annual sales in kilowatt-hours," any change in that information resulting should void the LEO. The reason the Commission incorporated the CPCN requirement into the North Carolina LEO test was to ensure that QFs "would be in a position to enter into a legally enforceable obligation" before a LEO can be established, "and that requires a certificate." *Order on Pending Motions*, p. 3, Docket No. E-100 Sub 74 (Feb. 13, 1995). The CPCN requirement was not intended to lock QFs in to the facility exactly as described in the CPCN application. And indeed, QFs are free to make a variety of changes to the information in the CPCN application (e.g. ownership and site layout), so long as they notify the Commission and the utility of the change, which they routinely do. However, as discussed above, NCSEA and NCCEBA agree that there should be limitations placed on a QFs ability to modify its AC capacity and annual energy production at the LEO-formation stage.

At the end of those existing contracts, those solar QFs will have substantial remaining useful life, and they will have the opportunity to sign a new contract with the utility under PURPA. Parties to this proceeding have addressed the appropriate treatment of existing QF capacity upon the expiration of their current standard offer PPAs with Duke. The Commission included this question as one of the discrete issues that parties should address with expert testimony and should be including in the evidentiary hearing.

The significance of this question is two-fold. First, H.B. 589 limits the availability of avoided capacity payments to years in which the utility's IRP has projected an identified capacity need.<sup>208</sup> Therefore, the treatment of expiring QF PPAs in the Companies' IRPs will directly impact the avoided capacity payments that are included in the avoided cost rates established during respective biennial avoided cost proceedings that are available to standard offer or negotiated QF contracts and that set benchmarks in multiple H.B. 589 programs. A greater capacity need as projected in the IRP will reflect the ability of new QFs to serve that need through a higher avoided capacity rate. Second, the treatment of expiring QF contracts in the IRP will directly impact existing QFs' ability to continue to receive appropriate compensation for the capacity value they are providing the utilities as existing generators if they commit to renewing their contracts with the Companies. Existing QFs who entered into standard offer PPAs under the Peaker Method prior to the enactment of H.B. 589 received full capacity payments in all years of their contracts, and those QFs continue to serve as existing generation capacity for the utility. As discussed below, while

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<sup>208</sup> N.C. Gen. Stat. § 62-156(b)(3) states that "a future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to G.S. 62-110.1(c) has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power."

this issue presents a somewhat complicated question of the appropriate treatment of existing QF capacity and its relationship to the determination of capacity need pursuant to the IRP, NCSEA and NCCEBA believe that the proposal of NCSEA Witness Johnson provides an appropriate roadmap for successfully resolving this issue. Alternatively, NCSEA and NCCEBA believe that all capacity needs identified in IRPs should be met through competitive procurement and that all existing QFs should have ability to compete to meet such needs.

A. DUKE AND THE PUBLIC STAFF'S RESPECTIVE POSITIONS ON EXPIRING QF PPAS

Duke has addressed this issue in its reply comments as well as in expert testimony filed in this proceeding. Duke witness Snider states in Direct Testimony that,

the Companies' IRPs have consistently and appropriately assumed that all wholesale purchase contract capacity is removed in the year after a wholesale contract expires and that QFs are not presumptively assumed to establish a new legally enforceable obligation ("LEO") to deliver capacity and energy to the utilities over a new fixed term in the future. At the time any merchant wholesale generator, including a QF, executes a PPA and commits itself to deliver energy and capacity over a future term, the Companies would then recognize the committed energy and capacity for IRP planning purposes, including as "existing capacity" for purposes of determining the utility's need for additional capacity in the future.<sup>209</sup>

From this description, it appears that Duke's IRPs simply indicate a capacity need in the first year after the relevant QF contract is set to expire. However, as revealed by Public Staff Witness Hinton:

In response to data requests submitted by the Public Staff and other parties, Duke indicated that for planning purposes, it also assumes that purchase power agreements (PPAs) are expected to be either renewed or replaced in

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<sup>209</sup> Tr. Vol. 6, p. 97.

kind. The assumptions as to renewal of wholesale power contracts as opposed to solar PPAs appear to be in conflict and indicate potentially different treatment of QF contracts.<sup>210</sup>

Further, based on discussions with Duke “the Public Staff understands that in order to establish the first year of needed capacity for avoided cost purposes, DEC and DEP utilize a parallel IRP expansion plan that does not include the Company’s assumption regarding the replacement of in-kind solar QF generation.”<sup>211</sup> It is based on this critique from the Public Staff that Duke has agreed to include a “Statement of Need section in future IRPs that identifies DEC’s and DEP’s first year of an avoidable need along with the supporting factors used to determine the avoidable need date.”<sup>212</sup> NCSEA and NCCEBA note that while Duke has criticized NCSEA and NCCEBA for what it characterizes as inconsistent positions on this issue in this proceeding, it is Duke that has obfuscated and obscured its treatment of expiring QF contracts in the context of IRP planning and the establishment of capacity need.

NCSEA and NCCEBA support the inclusion of a Statement of Need section in future IRPs to clearly identify the current first year of avoidable capacity need. Further, NCSEA Witness Johnson’s recommendation for addressing existing QFs with expiring PPAs should be approved in this proceeding and incorporated into this process.

#### B. NCSEA PROPOSAL FOR EXPIRING QF CONTRACTS

In Direct Testimony, NCSEA Witness Johnson included a proposal for how to address expiring QF PPAs and their respective capacity. NCSEA Witness Johnson identified the fact that existing “QFs are currently helping to meet the utilities’ capacity

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<sup>210</sup> Tr. Vol. 6, p. 308.

<sup>211</sup> *Id.*, p. 311 (emphasis added).

<sup>212</sup> Tr. Vol. 2, p. 99.

needs, and there is no principled basis for ceasing to pay them for the capacity costs they are helping to avoid, once their contracts come up for renewal.”<sup>213</sup> While it is certainly true that QFs are not required to sign new PURPA contracts with Duke upon the expiration of their initial contracts, it is also likely that many will do so. While alternative offtake opportunities may technically exist, it remains to be seen whether QFs will have viable offtake alternatives to signing new PPAs with Duke, such as wheeling into PJM or other RTOs or participating in future RFPs.

NCSEA and NCCEBA acknowledge that for IRP planning purposes, Duke may not be able to assume that a QF will renew its PPA (although NCSEA and NCCEBA note that it appears that Duke does assume that the expiring PPA will be replaced with another wholesale contract). NCSEA and NCCEBA also submit, however, that existing QFs are clearly providing a capacity resource to Duke that they are currently being compensated for, and those QFs will continue to do so if and when they enter into a new PPA. Allowing a QF to continue to provide that capacity resource rather than building duplicative generation is a more efficient result with respect to the utilization of capital resources as well as transmission and distribution resources.

To this end, NCSEA Witness Johnson proposed that “the Commission could require QFs to file notice with the utility at least 3 years before the current PPA expires indicating whether the QF is committing to continuously provide capacity and energy (without interruption) after the current contract expires - and specifying the length of that capacity commitment.”<sup>214</sup> With respect to the connection to the Companies’ IRPs and the respective capacity needs, NCSEA Witness Johnson explains:

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<sup>213</sup> Tr. Vol. 6, pp. 206-207.

<sup>214</sup> Tr. Vol. 6, p. 200.

To the extent the QF confirms its capacity will be continuously available, the utility would include that capacity in the IRP - treating it as a committed generation resource, and the QF would be entitled to receive full avoided capacity payments without interruption for the full duration of the commitment period (with the actual payment rate and other details to be determined when the new contract is signed).

If a QF does not make a post-contract commitment, it will retain maximum flexibility to choose its course of action when the existing contract expires - including the option to sell power on an energy-only “as available” basis, or to sign a new fixed price contract at the same terms applicable to a new QF (e.g. with little or no capacity payments).

If the QF does not make a capacity commitment, or it only commits to a short period of time, the utility would exclude the QF’s capacity from the IRP at the end of the contract term or commitment period. The removal of that capacity would be factored into the calculation of the extent to which a “need” for capacity exists each year - similar to the calculations that are developed when an existing generating plant is scheduled for retirement, or a wholesale purchase contract is expiring and is not expected to be renewed.<sup>215</sup>

NCSEA and NCCEBA submit that this proposal strikes the appropriate balance between the need for certainty as to the QFs commitment to renew its contract and allowing an existing QF to continue to receive compensation for the uninterrupted capacity it continues to provide to Duke. NCSEA and NCCEBA also believe it would be appropriate for the Commission to approve this process in principal and require parties to engage in stakeholder discussions to settle on any additional terms that would need to be addressed, including any appropriate penalty for a QF that committed to renew its contract and failed to do so.

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<sup>215</sup> Tr. Vol. 6, pp. 214-215.

Failing to allow existing QFs to continue to receive compensation for the capacity that they continue to provide Duke would also lead to the inequitable and inefficient result of the utilities “taking” QF capacity without compensation while, at the same time, satisfying that capacity resource provided by the QF through a utility-owned resource or through another bi-lateral contract in the IRP. This issue is amplified by the fact that when QF contracts expire, H.B. 589 limits the availability of negotiated contracts to 5 years. This increases the likelihood that the utility IRP will not project a capacity need during the relevant 5-year period, and the QF will only have access to an energy-only contract. Additionally, this position appears consistent with Duke’s statement in its reply comments that if “QFs have already begun contract extension or renewal negotiations with the Companies, the specific contract capacity may be included past the current contract expiration year to the expected year of expiration of the extended/new contract.”<sup>216</sup>

C. DUKE MISCHARACTERIZED RECENT NORTH CAROLINA LEGISLATION AT THE EVIDENTIARY HEARING

During the evidentiary hearing, Duke’s counsel asked NCSEA Witness Johnson questions regarding the application of a recent North Carolina House Bill 329 (“H.B. 329”) to NCSEA Witness Johnson’s proposal regarding expiring QF contracts. At the time of the evidentiary hearing, H.B. 329 had been ratified by both houses of the General Assembly but had not yet been signed by Governor Cooper. The bill was subsequently signed into law by the Governor on July 19, 2019.<sup>217</sup> The relevant language of the amendment is copied below:

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<sup>216</sup> *Duke Reply Comments*, pp. 46-47.

<sup>217</sup> S.L. 2019-132.

**SECTION 3.(a)** G.S. 62-156(b)(3) reads as rewritten:

"(b) At least every two years, the Commission shall determine the standard contract avoided cost rates to be included within the tariffs of each electric public utility and paid by electric public utilities for power purchased from small power producers, according to the following standards:

...

- (3) Availability and Reliability of Power. – The rates to be paid by electric public utilities for capacity purchased from a small power producer shall be established with consideration of the reliability and availability of the power. A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to G.S. 62-110.1(c) has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power, other ~~than~~ than for (i) swine or poultry waste for which a need is established consistent with G.S. 62-133.8(e) and (f) and (ii) hydropower small power producers with power purchase agreements with an electric public utility in effect as of July 27, 2017, and the renewal of such a power purchase agreement, if the hydroelectric small power producer's facility total capacity is equal to or less than five megawatts (MW)."

**SECTION 3.(b)** The exception for hydropower small power producers from limitations on capacity payments established in G.S. 62-156(b)(3), as amended by Section 3(a) of this act, shall not be construed in any manner to affect the applicability of G.S. 62-156(b)(3) as it relates to any other small power producer.

Section 3 of H.B. 329 amends N.C. Gen. Stat. § 62-156(b)(3), which includes the provision of H.B. 589 stating that a capacity need in the context of the avoided cost proceeding shall be limited to years in which the utility's most recently-approved IRP has identified a projected capacity need. H.B. 589 included an exclusion to this rule for swine or poultry waste facilities, and H.B. 329 amended H.B. 589 to add a second exclusion for "hydropower small power producers with power purchase agreements with an electric public utility in effect as of July 27, 2017, and the renewal of such a power purchase agreement, if the hydroelectric small power producer's facility total capacity is equal to or less than five megawatts (MW)."

During cross-examination Duke asked NCSEA Witness Johnson about the application of H.B. 329 to this proceeding and, specifically to NCSEA Witness Johnson's



proposal regarding expiring QF contracts.<sup>218</sup> Duke's counsel focused specifically on Section 3.b. which states "The exception for hydropower small power producers from limitations on capacity payments established in G.S. 62-156(b)(3), as amended by Section 3(a) of this act, shall not be construed in any manner to affect the applicability of G.S. 62-156(b)(3) as it relates to any other small power producer."<sup>219</sup> Duke asked whether NCSEA Witness Johnson would agree that Section 3.b. "provides that a renewal of an existing PPA for a [hydroelectric] small power producer will enable them to obtain that capacity value under a new PPA, and that's not contemplated for other types of small power producers?"<sup>220</sup>

As counsel for NCCEBA noted in an objection to Duke's question, NCSEA and NCCEBA submit that Section 3.b. of H.B. 329 was added specifically at the request of the solar industry in order to prevent the additional exemption for hydropower facilities in Section 3.a. from being construed as preventing the Commission from making an independent determination with respect to the proper determination of capacity need for small power producers upon the expiration of their contract.<sup>221</sup> Contrary to Duke's characterization, Section 3.b. specifically states that the exclusion for hydropower facilities should not be read to suggest that other small power producers may not continue to receive a full capacity payment upon the renewal of an existing contract. Indeed, it remains squarely within this Commission's authority to determine how this issue should be addressed in the context of this avoided cost proceeding and in the IRP proceeding. For example, NCSEA Witness Johnson's proposal would allow the IRP to reflect a capacity

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<sup>218</sup> Tr. Vol. 6, pp. 257-265.

<sup>219</sup> *Id.*, pp. 264-265.

<sup>220</sup> *Id.*

<sup>221</sup> *Id.*

need at the expiration of the QF PPA until a QF made a firm commitment to renew, at which point the utility's next IRP would no longer reflect that need, and the QF would continue to receive payment for its continued capacity provided to the utility.

For these reasons, NCSEA and NCCEBA recommend that the Commission approve NCSEA Witness Johnson's proposal described above.

D. ALTERNATIVELY, ALL CAPACITY NEEDS IDENTIFIED IN THE IRPs SHOULD BE MET THROUGH COMPETITIVE PROCUREMENT AND ALL EXISTING QFs SHOULD HAVE THE ABILITY TO COMPETE TO MEET SUCH NEEDS

Absent a reduction in demand, the expiration of a PURPA PPA will necessarily result in the need to replace the capacity supplied by that QF, unless the utility has been allowed to build new capacity prior to the PPA expiration. This unfair scenario is what really needs to be avoided by the Commission's policy on expiring PURPA PPAs. Allowing a utility to build new capacity without having first to consider whether existing QFs can meet that capacity need at a competitive cost is both unfair to QFs and bad for ratepayers.<sup>222</sup> The simple solution to this problem – and the best one for ratepayers – is to require the utilities to competitively procure any needed new capacity and to allow existing QFs to compete to meet such capacity need after the expiration of their current PPAs. This practice would be consistent with Duke Witness Snider's assertion during the evidentiary hearing that Duke plans to engage in competitive solicitations for future capacity needs and that the Commission has authority through the CPCN process to "ascertain whether or not the Company did an adequate solicitation of the marketplace before it places new generation into service."<sup>223</sup>

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<sup>222</sup> It would add insult to injury to allow this to occur where the capacity need was driven by expiring QF PPAs.

<sup>223</sup> Tr. Vol. 2, pp. 392-393.

## XII. AVOIDED COST AND AVOIDED CAPACITY RATES

### A. OVERSTATEMENT OF WINTER PEAK, SUMMER/WINTER ALLOCATION, AND THE PROPER VALUATION OF SOLAR TO THE GRID

As noted by NCSEA Witness Johnson, Duke has dramatically overstated their winter peak. North Carolina is a summer peaking state and, with the growth of solar, the “net” peak is in fact shifting from summer afternoon to other times. On this point, NCSEA, NCCEBA, and Duke almost agree.<sup>224</sup>

For DEC and DEP, however, the growth in solar energy will lower the Summer peak on a “net” basis (and the Summer peak will shift to later in the evening). Solar will have less of an impact in reducing the winter peak, so the net impact of more solar energy will be to reduce the magnitude and importance of the Summer peak while leaving the winter peak relatively unchanged. Although DEC and DEP’s have not done an adequate job modeling these changes, the direction of change is clear, and the magnitudes are substantial.<sup>225</sup>

Given this shift to a “net” winter peak, as NCSEA Witness Johnson points out, it is clear that Duke should be shifting demand side management and energy efficiency (“DSM/EE”) programs to have an emphasis on the winter months.<sup>226</sup> It is simply logical for DSM/EE programs to emphasize winter peaks given North Carolina’s abundant solar and summer peak. As NCSEA Witness Johnson notes, DSM/EE programs will be far more likely to be subscribed by customers who have pricing incentives to cover the infrequent and less predictable winter peaks.<sup>227</sup> NCSEA and NCCEBA recommends that the DSM/EE programs be altered to emphasize winter peaks, in a gradual manner, to allow customers

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<sup>224</sup> NCSEA Initial Comments, Attachment 1 (“Johnson Affidavit”), p. 38.

<sup>225</sup> *Id.*

<sup>226</sup> *Id.*

<sup>227</sup> *Id.*

and utilities the opportunity to adapt to the new conditions. This will reflect more truly the “net” peak challenges.

In response to NCSEA’s and NCCEBA’s proposal, Duke offers the moderate success of the winter-based DEP EnergyWise Home program, which Duke claims included high amounts of effort to achieve a modest result of 15 MW over 10 years for a customer base of approximately 150,000.<sup>228</sup> While NCSEA and NCCEBA do not contest the modest success of that program, Duke has not provided a response to the larger underlying assumption by NCSEA Witness Johnson – that the Duke Utilities could wholly change their DSM assumptions (set forth in their IRP filings) and change all programs to more succinctly fit the winter peaks in this state.<sup>229</sup> Duke asks NCSEA Witness Johnson for “empirical evidence” that such a shift is feasible while calling him “grossly optimistic”<sup>230</sup>, but visibility into the underlying data necessary for such a study from NCSEA Witness Johnson is limited. It simply follows logically that the abundance of solar should provide an incentive for Duke to move DSM/EE programs to emphasize winter peaks. However, as NCSEA Witness Johnson points out in his direct testimony, Duke’s IRP assumptions, Astrapé Study, and overarching assumptions with regard to seasonal peak demand are flawed and it results in Duke benefitting from solar capacity in the summer (utilized to meet the true peak demand) without having to pay what should be the market rate.<sup>231</sup>

As NCSEA Witness Johnson states, Duke’s proposed capacity rate design does not reflect the true nature of solar in a summer-peaking state. While Duke benefits from the assumption that online utility scale solar will be there to provide capacity when needed as

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<sup>228</sup> *Duke Reply Comments*, p. 63.

<sup>229</sup> *Johnson Affidavit*, p. 39.

<sup>230</sup> *Duke Reply Comments*, p. 64.

<sup>231</sup> *NCSEA Witness Johnson Direct*, p. 48.

the summers are getting hotter and hotter, this fails to consider the inequitable nature of this relationship and its effect on solar development. As stated more fully in *NCSEA Reply Comments*, Duke has devalued the capacity contributions of solar QFs and eliminated the capacity benefits solar QFs can provide by overstating winter effects and undervaluing summer capacity values.<sup>232</sup> Furthermore, Duke's flawed methodologies, as explained herein and in NCSEA's and SACE's respective filings in this proceeding, result in an overstatement of winter risk and an unfair and unnecessary reallocation of capacity.

As noted by Duke Witness Snider, there is either very limited or no new PURPA development in North Carolina.<sup>233</sup> Solar development has slowed down, save the H.B. 589 programs, which are also more tenuously moving forward than the General Assembly likely anticipated, particularly at the utility-scale level. Duke's capacity assumptions by season should not assume solar development will always be there to fulfill need when such a need is not being paid for at a fair market price. North Carolina uses more power during summer than winter, and while solar generation currently helps to limit the costs of summer generation, that might not always be the case if market forces cause solar to stop development.

1. TIMING OF GENERATION AND THE FALLACY OF THE UTILITIES' AVOIDED CAPACITY PREDICTIONS

The time frame for the utilities' avoided cost and QF rate calculations are arbitrary and unrealistic insofar as they assume the avoided cost rates will be placed in service much too quickly. It would be more appropriate to use a later, more reasonable starting date for

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<sup>232</sup> *NCSEA's Reply Comments*, p. 8, Docket No. E-100, Sub 158 (March 27, 2019) ("*NCSEA Reply Comments*").

<sup>233</sup> Tr. Vol. 2, p. 348..

the QF contracts given that new QFs eligible for the avoided cost rate coming out of this proceeding will not come online for a few years. According to NCSEA Witness Johnson, it would be reasonable to assume a QF eligible for the rates coming out of this proceeding “will be place[d] in service and start receiving revenues on or about December 31, 2021[.]”<sup>234</sup> The faulty assumption that QFs will come online in some near-to-date time is particularly problematic when considering avoided capacity rates as the assumption about capacity rates will include years where the new QF is not yet online – i.e., a new QF that requests interconnection right after the order in this docket is made establishing rates will have an approximately 3-year waiting period before the QF comes online and, accordingly, its 10-year standard contract will have, effectively, a 30% reduction in avoided capacity payments.<sup>235</sup> To allow for a later in-service date in their models would provide a more reasonable and real-world reflection of QF generation.

Duke opposes NCSEA’s and NCCEBA’s position on this stating that NCSEA and NCCEBA have not provided sufficient evidence beyond mere claims and both Duke and Dominion state that legally they are not required to make any such assumptions regarding in-service date and the QF can control its destiny by moving its Legally Enforceable Obligation (“LEO”) date.<sup>236</sup> Dominion also states that the implementation of such moving starting dates when entering into a contract with new QFs would be difficult to do and unreasonably burdensome on the utilities.

As an initial matter, neither NCSEA, NCCEBA, or NCSEA Witness Johnson are suggesting that specific QFs have some optionality or otherwise directly benefit from

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<sup>234</sup> *Johnson Affidavit*, p. 59.

<sup>235</sup> *Johnson Affidavit*, p. 59.

<sup>236</sup> *Duke Reply Comments*, pp. 48-49.

determining some sort of arbitrary in-service date. NCSEA's and NCCEBA's sole point on this matter is that the practical in-service dates of QFs *right now* are three years away, but the avoided cost filings made by Duke and Dominion reflect a near instantaneous in-service date. As for Duke requesting evidence about these assumptions, NCSEA and NCCEBA has not offered into evidence the slow-down currently being incurred in the interconnection queue, but it has been referenced countless times in numerous dockets. Specifically, NCSEA and NCCEBA would encourage the Commission and Duke to review the Interconnection and CPRE dockets to see a robust discussion regarding the interconnection queue issues and its proposed reforms.

NCSEA and NCCEBA believe that, until the interconnection issues are solved in such a way that the avoided cost and capacity rates closely align with QF interconnection times, Duke and Dominion should alter their models to allow for a later in-service date to more accurately reflect reality.

#### B. AVOIDED ENERGY COSTS

As in the E-100, Sub 148 proceeding, the issues related to Duke and Dominion's calculation of avoided energy costs are disparate and, in Duke's case, contrary to the Commission's determination in the Sub 148 proceeding.

##### 1. NATURAL GAS FORECASTING

Dominion and Duke have significantly different forecasts for the next 10 years of gas prices in the benchmark Henry Hub market. Dominion's forecast is based on gas forward market prices for the initial 18 months, then transitions to a fundamentals forecast

by 36 months.<sup>237</sup> In contract, Duke utilizes a full 10 years of forward market prices.<sup>238</sup> NCSEA and NCCEBA support the Dominion position as it reflects a “deep and liquid” near-term market for the 18-month forecast and then transitions to the fundamental forecast, which is a more appropriate forecast than Duke’s.<sup>239</sup>

Duke takes the position that because it has been able to enter into a limited number of long-range natural gas forward purchases, those are indicative of market prices going out for that length of time: “[s]ince the Sub 148 Proceeding, the Companies have purchased 10-year forward gas contracts on five separate occasions (one in 2016, two in 2017 and two in 2018) to support the Companies’ recent IRPs and avoided cost filings and to demonstrate forward market liquidity ten years into the future.”<sup>240</sup> Duke further states that “reliance on lagging fundamental forecast pricing has proven to be inaccurate” and that the 10-year term is more accurate to what they see in the market.<sup>241</sup>

The Public Staff agrees with NCSEA and NCCEBA to a point. The Public Staff recommends that Duke utilize five-year forward market data before transitioning to the Duke fundamentals forecast.<sup>242</sup> The Public Staff analyzed a number of other utilities around the country in finding that Duke’s proposal for ten-years was inappropriate it may not reflect actual fuel prices.<sup>243</sup> Furthermore, Duke has been unable to provide another utility in the U.S. who utilizes ten-year forward pricing to forecast natural gas prices. NCSEA and NCCEBA agrees with the Public Staff and notes that the Public Staff does not recommend

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<sup>237</sup> *Beach Affidavit*, p. 3.

<sup>238</sup> *Id.*

<sup>239</sup> *Beach Affidavit*, p. 3.

<sup>240</sup> *Duke Initial Statement*, p. 20.

<sup>241</sup> *Id.* at 21.

<sup>242</sup> *Public Staff Initial Comments*, pp. 27-28.

<sup>243</sup> *Id.* at 25.



a five-year forwards forecast but rather that Duke “use no more than five years of forward market data.”<sup>244</sup>

In his testimony, Duke Witness Snider indicated that “the marketplace, in my opinion, is by far and away the best not estimate, but the -- more importantly, is the price at which transactions are taking place.”<sup>245</sup> Essentially, Duke Witness Snider takes the position that the marketplace has allowed for ten-year natural gas purchases to be made, and, accordingly, the natural gas forecasts should reflect the marketplace that allowed for the ten-year purchase contracts. The issue, of course, is no other utility uses a forward market of ten-year contracts to establish natural gas rates. Duke Witness Snider pointed to the prevalence of solar in North Carolina as requiring the unique purchase contracts of natural gas: “North Carolina is uniquely situated in the very position that precipitated us going out and buying gas that far into the future to ensure we had this indifference principle in place at the right level.”<sup>246</sup> Duke Witness Snider was not, however, able to point out why Dominion, which also is partially located in the solar-heavy state of North Carolina, did not require or request 10-year forward natural gas forward markets, but rather a mere 18 months.<sup>247</sup>

NCSEA and NCCEBA believe the 10-year forward market prices will have the effect of artificially lowering the avoided cost rate. Such a projection is not based upon common practices and not necessarily reflective of the market in the coming years. Furthermore, as set forth more fully below, Duke’s hedging policies would not allow Duke to purchase sufficient amounts of gas in ten-years forward contracts to display the solar

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<sup>244</sup> *Id.* at 28.

<sup>245</sup> Tr. Vol. 3, p. 97.

<sup>246</sup> Tr. Vol. 3, p. 103.

<sup>247</sup> Tr. Vol. 3, p. 105.

generation that they claim require such long-range inputs. NCSEA and NCCEBA request the Commission reject the Duke natural gas forecast proposal.

## 2. DUKE’S POSTURE IN OTHER STATES ON NATURAL GAS FORECASTS

The Duke Energy utility located in Ohio, Duke Energy Ohio (“Duke Ohio”) have recognized the issues in forecasting and hedging natural gas. As noted in the *NCSEA Initial Comments*, in 2017, Duke Ohio requested that the Public Utilities Commission of Ohio approve subsidization of an uneconomic coal plant on the basis that it provided a hedge against natural gas price risk. Duke Ohio Witness Judah Rose presented direct testimony that (i) recent declines in natural gas prices are unsustainable and cannot continue – thus over the long term gas prices will increase and (ii) it is not accurate to use the price of gas futures to project gas prices more than 1-2 years in the future.<sup>248</sup> Furthermore, as noted by NCSEA and NCCEBA previously, the market for natural gas is historically a very volatile market amongst the commodities and is susceptible to large jumps in pricing.<sup>249</sup>

In Florida, Duke Energy Florida, Florida Power & Light, Gulf Power, and Tampa Electric Company (“TECO”) filed a joint petition in 2016 to modify their fuel hedging programs, stating in part:

[The] increased dependence on natural gas means customers will have significant exposure to the uncertainties of natural gas prices if hedging were completely discontinued. *While natural gas prices have trended downward in recent years, neither future gas prices nor the level of price volatility can be predicted with any certainty.* Additionally, the recent downward trend in natural gas market prices cannot continue indefinitely.

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<sup>248</sup> *NCSEA Initial Comments*, p. 24, quoting *Direct Testimony of Judah L. Rose on behalf of Duke Energy Ohio*, March 31, 2017, available at <https://www.eenews.net/>, p. 54 (“Ohio Testimony”) (“Our forecast is that the recent multi-year trend (e.g., post 2008) of low 9 supply area natural gas prices will continue in the near-term, but over time, 10 natural gas prices increase in real terms and even more in nominal terms relative 11 to 2016.”).

<sup>249</sup> *NCSEA Initial Comments*, p. 25, quoting the Ohio Testimony.

Factors such as production costs, weather, environmental regulations and exportation impact natural gas supply and demand, as well as natural gas price volatility.<sup>250</sup>

In response to these Duke data points from Ohio and Florida, Duke says such testimony from their corporate footprint is “of little probative value” because it does not reflect the recently-contracted for forward price contracts delivered to Duke systems in North Carolina.<sup>251</sup> Duke’s reliance on this point is ill-fitting. 10-year forward natural gas contracts that Duke has been able to procure reflect a negotiation between Duke and natural gas vendors – they do not represent the entirety of a marketplace, to the extent there even is one. Many other factors may come into play when the 10-year forward marketplace contains such a shallow pool of market participants. Elsewhere, Duke has warned against the volatility of natural gas prices and how the bottom may drop out; here, Duke says, “we have made contracts reflective of these numbers, so our entire avoided cost metric should reflect our contracts” despite the fact that the reality and the marketplace will likely shift in the coming years

### 3. HEDGING

NCSEA and NCCEBA believe that the Commission should direct Duke to reinstate hedging benefits in a revised avoided cost proposal and that Duke should use an approach to calculating the long-term hedging costs developed for the Maine Public Utilities Commission (“Maine PUC”). “This approach determines the cost to fix upfront the cost of the natural gas displaced over 10 years by the output of the renewable QF. This method

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<sup>250</sup> NCSEA *Initial Comments*, p. 25, quoting *Joint Petition by Investor-Owned Utilities for Approval of Modifications to Risk Management Plans*, ¶ 5, Florida Public Service Commission Docket No. 160096-EI (Apr. 22, 2016) (emphasis added).

<sup>251</sup> *Duke Reply Comments*, pp. 20-21.

results in gas hedging costs of about \$0.007 per kWh, using NCSEA's and NCCEBA's recommended gas price forecast."<sup>252</sup> The Maine PUC method calculates the

additional costs to fix the fuel costs of a marginal gas-fired generator for a long-term period, compared to purchasing gas at prevailing short-term market prices on an "as you go" basis. The method compares the long-term cost of the displaced gas generation at a risk-free discount rate (U.S. Treasuries) versus the same cost discounted at the utility's weighted average cost of capital (WACC). The difference represents the hedging benefit of fixing the cost of gas, removing the market risk that volatile gas prices could make gas-fired generation at times uneconomic.<sup>253</sup>

In response to NCSEA's and NCCEBA's proposal, Duke maintains a position that the "put-option" is an unpaid benefit to QFs, along with other factors, that offsets the need to include hedging values in standard offer avoided cost rates.<sup>254</sup> NCSEA and NCCEBA dispute this position and so does the Public Staff who state that removing hedging benefits "would essentially require QFs to compensate utilities for the right to sell their generation" and that the risk of overpayment was already addressed adequately by the Commission in E-100, Sub 148 through the PAF.<sup>255</sup> NCSEA and NCCEBA agree with the Public Staff that the QF should not be required to essentially compensate Duke for its right to sell generation and, instead, recommends the Maine PUC method described herein and more explicitly in the Beach Affidavit.

#### 4. FIRM PIPELINE CAPACITY COSTS

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<sup>252</sup> *Beach Affidavit*, p. 4.

<sup>253</sup> *Id.* at 17.

<sup>254</sup> *Duke Reply Comments*, p. 26, fn. 65 ("Specifically, the Companies have not included the 0.028¢/kWh hedging value that was included in DEC's and DEP's Sub 140 and Sub 148 standard offer rates.").

<sup>255</sup> *Public Staff Initial Comments*, p. 28-29.

Duke and Dominion have assigned significant avoided capacity costs to the winter months, but the peaker that is the basis for QF capacity costs requires a firm fuel supply to operate during peak winter periods.<sup>256</sup> Pipelines are often constrained during peaking winter periods, so either a firm pipeline capacity or an assurance of another way to burn an alternate fuel such as oil in order to offset pipeline constraint issues.<sup>257</sup> Firm pipeline capacity is likely the least-cost option, in this scenario, given current oil prices, so the additional costs needed to firm the CT peaker's fuel supply should be added to the costs used as the basis for QF capacity rates in winter months.<sup>258</sup>

Duke argues that it does not reserve such firm pipeline capacity and believes it is inappropriate to “deviate from the Peaker Methodology” by directly assigning a cost premium to a winter capacity period.<sup>259</sup> NCSEA and NCCEBA are uncertain why Duke is unwilling to deviate from its typical Peaker Methodology, when Duke is more than willing to introduce a completely new charge it alleges arises out of solar intermittency, and NCSEA and NCCEBA believe this concern should be disregarded. Furthermore, Duke has so heavily weighted the winter peak that when valuing capacity, it cannot be ignored that pipeline constraint could seriously and negatively affect Duke's systems during a period where pipeline constraint is most prevalent. For all these reasons, NCSEA and NCCEBA encourage the Commission to require Duke to account for firm pipeline capacity costs in its avoided capacity rates for winter peak periods.

### **XIII. RATE DESIGN**

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<sup>256</sup> *Beach Affidavit*, p. 4.

<sup>257</sup> *Id.*

<sup>258</sup> *Id.*

<sup>259</sup> *Duke Reply Comments*, p. 35.

NCSEA and NCCEBA request the Commission reject the proposed *Rate Design Stipulation* as it improperly weights winter capacity too heavily as noted above. Below are further reasons why Utilities' rate designs do not sufficiently meet ratepayer needs and truly reflect avoided costs of the Utilities.

A. PRICE SIGNALS

NCSEA and NCCEBA continue to believe Duke and Dominion should provide geographic price signals to incentivize the building of solar QFs in areas where there is not as much congestion. This is consistent with the desire for more granular rate design – the Commission should direct Duke and Dominion to develop tariffs incorporating such geographic price signals. QF rates that reflect the impact of geographic diversity will also help to ensure QF prices are economically efficient and encourage entrepreneurship, innovation, and sound investment decisions.<sup>260</sup> Incentivizing geographic diversity through price signals will also help to alleviate transmission and distribution costs through a better distributed system. Similarly, geographic diversity, incentivized through price signals, of solar QFs will reduce re-dispatch costs. These price signal locations should be determined via hosting capacity maps, which could provide the information needed to developers and utilities to allow for a more efficient use of the grid.

Duke contends that they have adhered to the prior avoided cost orders in providing more granular rate designs, and they have to some extent. However, there is no reason, given the need for interconnection queue relief in this state, to ignore the potential to solve some of the queue problems through price signals. Duke also contends that because Duke has the “capability to reconfigure the distribution grid to shift load and generation across

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<sup>260</sup> *Johnson Affidavit*, p. 10.

distribution circuits to achieve a better balance” then a shift in line with geographic price signals will “alter the line loading and thereby change the cost/benefit of having generation on a specific circuit.”<sup>261</sup> NCSEA and NCCEBA are not proposing that the geographic price signals will limit Duke’s ability to reconfigure the distribution grid to shift load, but instead are proposing a means to allow additional diverse generation that should alleviate the need to shift load so dramatically or, at least, to relieve the interconnection queue. We believe that the Commission should recommend that geographic price signals should be included in new rate designs developed and presented by Duke and Dominion.

Furthermore, as set forth above, Duke’s seasonal price signals highlight an overstatement of winter risk that is backed by faulty studies.<sup>262</sup> Additionally, Duke agrees that regarding “real-time price signals”: “time-of-day pricing periods and optional, real-time pricing tariffs for QFs could better align the Companies’ actual avoided costs[.]”<sup>263</sup> However, despite this agreement, Duke believes they have made sufficient granular rate design proposals at this time. NCSEA and NCCEBA encourage the Commission to require Duke to propose the above-outlined rate designs as they would more adequately reveal the Utilities’ true avoided costs.

#### **XIV. PERFORMANCE ADJUSTMENT FACTOR**

NCSEA and NCCEBA agree that the calculation of PAF, which accounts for potential generation reliability hiccups from QFs in the avoided cost calculation, should be forward-facing as prescribed by the Public Staff.<sup>264</sup> This will better reflect continued

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<sup>261</sup> *Duke Reply Comments*, p. 74.

<sup>262</sup> See also, *NCSEA Initial Comments*; *NCSEA Reply Comments*; and, *SACE’s Initial Comments*.

<sup>263</sup> *Duke Reply Comments*, p. 74.

<sup>264</sup> *NCSEA Reply Comments*, p. 12; see also *Public Staff Initial Comments*, pp. 70-72.

upgrades to the grid accommodating more technologies. However, NCSEA and NCCEBA believe that the Public Staff could take a more determinative step in requesting a true reflection of the current PAF calculation. NCSEA and NCCEBA believe that Duke has biased its current PAF calculations and that the Duke avoided cost proposal discriminates against QFs and understates their contribution to capacity during peak months, but rather than recalculating on its own, NCSEA and NCCEBA recommend that the Commission reject Duke's PAF proposal and adopt the proposal of a PAF between 1.08 and 1.10.<sup>265</sup> Further, as stated above, NCSEA and NCCEBA agree with the Public Staff's position that PAF mitigates the Utilities' risk of overpayment to QFs and no further actions are necessary to offset potential overpayment such as the removal of hedging values.<sup>266</sup> Finally, and as noted in the evidentiary hearing, NCSEA and NCCEBA have concerns for Duke's PAF modeling insofar as they have not specifically attributed how the PAF calculation works when an extreme weather condition or event overlaps a scheduled maintenance time, despite the fact that scheduled maintenance during an extreme weather condition or event will clearly manipulate the PAF.<sup>267</sup> NCSEA and NCCEBA requests the Commission direct Duke's future PAF calculations explicitly limit overlap between maintenance and extreme weather conditions.

### CONCLUSION

For all the reasons set forth above, NCSEA and NCCEBA request that the Commission reject the Utilities' avoided cost plans and request for new rate design including the Solar Integration Charge and Re-Dispatch Charge and require the Utilities to

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<sup>265</sup> NCSEA Initial Comments, pp. 31-32.

<sup>266</sup> Public Staff Initial Comments, pp. 28-29.

<sup>267</sup> Tr. Vol. 2, pp. 311-312.



file new avoided cost plans, which provide accurate representations of the avoided cost of both energy and capacity, including highlighting the benefits of distributed generation and solar, commensurate with the findings and conclusions made in this filing and also in **Exhibit 1**. NCSEA and NCCEBA also request that the Commission reject the Utilities unsubstantiated and unlawful attempts to re-write their existing standard offer PPAs and Terms and Conditions to materially alter the rights and obligations of the parties, as well as Duke's proposed prospective revisions to its standard-offer PPA to the extent such revisions are inconsistent with the revisions supported by NCSEA and NCCEBA herein and in **Exhibit 1**. NCSEA and NCCEBA also requests the Commission determine an appropriate way for QFs with expiring PPAs to work with the Utilities, either via providing a threshold timeline as proposed by NCSEA Witness Johnson or, otherwise, some meaningful way for an expiring-contract QF be given an opportunity to meet the Utility's coming capacity needs.

On the discrete issues of the Solar Integration Charge and the Re-Dispatch charge, NCSEA and NCCEBA request that the Commission reject the respective charges, defer the issue to an appropriate ratemaking proceeding or the next biennial avoided cost proceeding, and require Duke and Dominion to immediately initiate a joint stakeholder process, with independent technical oversight and Commission oversight in a manner in which the Commission sees fit, wherein the stakeholders and the Utilities shall exchange in a large-scale and meaningful evaluation of the value of distributed generation or simply distributed solar, should the Commission see that as more appropriate. This process would include stakeholder input at every level – hiring consultant(s), providing a list of inputs, providing data for inputs, making determinations of weighting to data, reviewing and providing

feedback on model assumptions and limitations, and determining proper validations of the model to ensure accuracy and reliability. Also, this stakeholder process would need to be ongoing to reflect changes in the market, similar to the way the Idaho Study is consistently re-formulated.

Should the Commission determine a Solar Integration Charge and/or Re-Dispatch Charge is necessary, supported by the record, and must be adopted now, NCSEA and NCCEBA request that (i) the Commission either not make a decision in this proceeding as to the applicability of such a charge to the CPRE and GSA program, but defer such decision to the dockets governing those programs, or rule that any SISC should not apply to those programs; (ii) limit any charge to the initial rates proposed by the utility with no increases over the life of PPAs entered into or LEOs established before the proposed charges can be more thorough evaluated.<sup>268</sup>

Respectfully submitted, this the 4th day of September, 2019.

/s/ Peter H. Ledford  
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<sup>268</sup> If CPRE and GSA projects are excluded, there are few if any projects likely to be subjected to any Solar Integration Charge in the next two years.

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**CERTIFICATE OF SERVICE**

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

This the 4th day of September, 2019.

/s/ Peter H. Ledford  
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# Exhibit 1

**PURCHASE POWER AGREEMENT**

between

**DUKE ENERGY CAROLINAS, LLC**

and

**SELLER NAME**

**“Facility Name” Project**

**Initial Delivery Date:** *(date interconnection facilities installed)*

**PURCHASE POWER AGREEMENT BY A  
QUALIFYING COGENERATOR OR SMALL POWER PRODUCER**

1 **THIS PURCHASE POWER AGREEMENT** (“Agreement”) is made this \_\_\_\_\_ day of  
2 \_\_\_\_\_, 20\_\_\_\_, by and between

3  
4 **DUKE ENERGY CAROLINAS, LLC,**  
5 a North Carolina Limited Liability Company (“Company”),

6  
7 and

8  
9 \_\_\_\_\_,  
10  
11 a(n) [*insert place of formation* \_\_\_\_\_] [*insert entity type* \_\_\_\_\_] (“Seller”), for the

12  
13 “ \_\_\_\_\_,” Project

14  
15 Seller hereby certifies that the Facility, as defined below, (is/is not) "new capacity", as defined by the  
16 Federal Energy Regulatory Commission (FERC), and that construction of the Facility (was/was not)  
17 commenced on or after November 9, 1978, and that the Facility is or will be a qualifying facility as  
18 defined by the Federal Energy Regulatory Commission (“FERC”) pursuant to Section 210 of the  
19 Public Utility Regulatory Policies Act of 1978 [*and which is or will be a hydroelectric generating*  
20 *facility owned and operated by a small power producer as defined in G.S. 62-3(27a) - (if*  
21 *applicable)]]. The Facility as defined herein (the “Facility”) shall consist of that certain [*insert*  
22 *description of the Facility including fuel type and Nameplate Capacity rating in AC-and-DC] ~~where~~*  
23 *applicable, identify any Storage Resource connected to or incorporated into the Facility along with*  
24 *the Storage Resource’s capacity (MW and MWh)]—which is located at [*insert facility address*].**

25  
26 (Hereinafter, the parties are also referred to individually as a “Party” and collectively as the “Parties”).

27  
28 In consideration of the mutual covenants herein contained, the Parties hereto, for themselves, their  
29 successors and assigns, do hereby agree to the following:

30  
31 **1. Service Requirements**

32 1.1 Seller shall sell and deliver exclusively to Company all of the electric power generated by the  
33 Facility, net of the Facility’s own auxiliary electrical requirements, and Company shall  
34 purchase, receive, use and pay for the same, subject to the conditions contained in this  
35 Agreement. Upon the completion of the installation, by Company, of its system upgrades and  
36 interconnection facilities at the point of delivery of Seller's and Company's conductors, Seller  
37 shall become responsible for the payment to Company of any and all charges that may apply,  
38 whether or not Seller actually delivers any electricity to Company. If Seller requests retail  
39 electric service for the Facility’s auxiliary electrical requirements from Company when Seller’s  
40 generation is reduced, such power shall be provided to Supplier pursuant to a separate electric  
41 service agreement under Company’s rate tariffs appropriate for such service.

42  
43 1.2 Electricity supplied by Seller shall be [*single (1)/three (3)*] phase, alternating at a frequency of  
44 approximately sixty (60) cycles, and at a delivery voltage of approximately \_\_\_\_\_ volts,  
45 \_\_\_\_\_ wires at a sufficient power factor to maintain system operating parameters as specified  
46 by Company.  
47

48 1.3 Delivery of said Seller’s power shall be at a point of delivery described as follows:  
 49 \_\_\_\_\_  
 50  
 51 1.4 The Contract Capacity of the Facility, as defined in the Terms and Conditions for the Purchase  
 52 of Electric Power is \_\_\_\_\_ AC kW/MW. The maximumestimated annual energy  
 53 production of the Facility is \_\_\_\_\_ kWh.  
 54

55 **2. Rate Schedule**

56 The sale, delivery, and use of electric power hereunder, and all services of whatever type to be  
 57 rendered or performed in connection therewith, shall in all respects be subject to and in  
 58 accordance with Company’s Rate Schedule PP, Electricity No. 4, North Carolina \_\_\_\_\_  
 59 Revised Leaf No. 90, [*Variable Rate*], [*10-year Fixed Long-Term Rate*] Option [A][B] for  
 60 [*Distribution*][*Transmission*] (“Rate Schedule”) and the Terms and Conditions for the Purchase  
 61 of Electric Power, both of which are now on file with the North Carolina Utilities Commission  
 62 (“Commission”), and are hereby incorporated by reference and made a part hereof as though  
 63 fully set forth herein. Said Rate Schedule and Terms and Conditions for the Purchase of Electric  
 64 Power are subject to change, revision, alteration or substitution, either in whole or in part, upon  
 65 order of said Commission or any other regulatory authority having jurisdiction, and any such  
 66 change, revision, alteration or substitution shall immediately be made a part hereof as though  
 67 fully written herein, and shall nullify any prior provision in conflict therewith.  
 68

69 The language above beginning with “Said Rate Schedule” shall not apply to the Fixed Long-  
 70 Term Rates themselves, but it shall apply to all other provisions of the Rate Schedule and Terms  
 71 and Conditions for the Purchase of Electric Power, including but not limited to Variable Rates,  
 72 other types of charges (e.g., administrative charges), and all non-rate provisions.  
 73

74 **3. Initial Delivery Date**

75 The term of this Agreement shall be a minimum of 5 years when contracting for capacity  
 76 payments and shall begin upon the first date when energy is generated by the Facility and  
 77 delivered to the Company and continuing for the term specified in the Rate Schedule paragraph  
 78 above and shall automatically extend thereafter unless terminated by either party by giving not  
 79 less than thirty (30) days prior written notice. Any automatic extension of this Agreement will  
 80 be at the Variable Rates in effect at the time of extension. The term shall begin no earlier than  
 81 the date the Company’s Interconnection Facilities are installed and are ready to accept electricity  
 82 from the Seller which is requested to be \_\_\_\_\_. The Company at its sole discretion  
 83 may terminate this Agreement on \_\_\_\_\_, 20\_\_ (30 months following the date of  
 84 the order initially approving the rates selection shown above which may be extended beyond 30  
 85 months if construction is nearly complete and the Seller demonstrates that it is making a good  
 86 faith effort to complete its project in a timely manner<sup>1</sup>) if the Seller is unable to provide  
 87 generation capacity and energy production consistent with the energy production levels  
 88 specified in Provision No. 1.4 above. This date may be extended by upon mutual agreement by  
 89 both parties.

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<sup>1</sup> Eligible Sellers establishing a Legally Enforceable Obligation on or before November 15, 2016, and seeking payment under rates approved in Docket No. E-100, Sub 140, shall continue to be eligible for such rates, even if they fail to commence delivering power to the utility on or before September 10, 2018, pursuant to Section 1.(c) of Session Law 2017-192, unless the Seller’s nameplate capacity along with the combined nameplate capacity of generation facilities connected or with priority rights under the North Carolina Interconnection Procedures to be connected ahead of Seller to the same general distribution substation transformer exceeds the nameplate capacity of the transformer, as determined by Company. The term for these extended Agreements available to eligible E-100 Sub 140 Sellers shall commence on September 10, 2018 and expire no later than 15 years from that date.



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**4. Interconnection Facilities**

Unless otherwise required by Company, an Interconnection Agreement pursuant to the North Carolina Interconnection Procedures, Forms, And Agreements For State-Jurisdictional Generator Interconnections (Interconnection Standard) shall be executed by Seller, including payments of all charges and fees associated with the interconnection, before Company will accept this Agreement. *(Either sentence (a) or (b) as follows is inserted into the agreement as appropriate)* (a) The Interconnection Facilities Charge shall be specified in the Interconnection Agreement, or (b) The Interconnection Facilities Charge shall be 1.0 % of the installed cost of metering and other equipment and is \$\_\_\_\_\_ per month.

**5. Energy Storage.**

If the Facility is to be equipped with battery storage or other energy storage device (the “Storage Resource”), the Storage Resource shall be identified in this Agreement. In all cases the Storage Resource must be charged solely by the Facility and the use of any Storage Resource shall be operated and equipped in accordance with the system operator’s Energy Storage Protocol, a copy of which is attached hereto as Exhibit A, as may be modified from time to time by the system operator, subject to approval by the Commission (the “Energy Storage Protocol”).

**6. Reporting Requirements**

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

Upon the execution by Company and Seller in the block provided below, this Agreement together with attachments shall become an agreement for Seller to deliver and sell to Company and for Company to receive and purchase from Seller the electricity generated and delivered to Company by Seller from the above described qualifying generating facility at the rates, in the quantities, for the term, and upon the terms and conditions set forth herein.

**Witness as to Seller:**

\_\_\_\_\_, Seller  
Printed: \_\_\_\_\_  
By \_\_\_\_\_  
Printed: \_\_\_\_\_  
Title \_\_\_\_\_  
This \_\_\_\_ day of \_\_\_\_\_, 20\_\_\_\_

**ACCEPTED: DUKE ENERGY CAROLINAS LLC**

**Mail Payment/Bill to:**

By \_\_\_\_\_  
Title \_\_\_\_\_  
This \_\_\_\_ day of \_\_\_\_\_, 20\_\_

Exhibit A  
Energy Storage Protocol

OFFICIAL COPY

Sep 04 2019

## TERMS AND CONDITIONS FOR THE PURCHASE OF ELECTRIC POWER

1. PURCHASE POWER AGREEMENT

These "Terms and Conditions" provide a mechanism through which Duke Energy Carolinas, LLC, hereafter called "Company," will agree to purchase energy or capacity or both from an Eligible Qualifying Facility as defined in the Purchased Power Schedule PP. This Purchase Power Agreement is solely for the purchase of electricity produced by Seller's generation, net of generator auxiliary requirement, and does not provide for the sale of any electric service by Company to Seller.

- (a) Description - The Purchase Power Agreement (hereinafter sometimes termed "Agreement") shall consist of (1) Company's form of Purchase Power Agreement when signed by Seller and accepted by Company, (2) the applicable Schedule for the purchase of electricity as specified in the Purchase Power Agreement, and (3) these Terms and Conditions for the Purchase of Electric Power (hereinafter referred to as "Terms and Conditions"), and all changes, revisions, alterations therein, or substitutions therefor lawfully made.
- (b) Application of Terms and Conditions and Schedules - All Purchase Agreements in effect at the effective date of this tariff or that may be entered into in the future, are made expressly subject to these Terms and Conditions, and subject to all applicable Schedules as specified in the Purchase Power Agreement, and any changes therein, substitutions thereof, or additions thereto lawfully made, provided no change may be made in rates or in essential terms and conditions of this contract except by agreement of the parties to this contract or by order of the state regulatory authority having jurisdiction (hereinafter "Commission").
- (c) Conflicts - In case of conflict between any provision of a Schedule and of these Terms and Conditions, the provision of the Schedule shall prevail.
- (d) Waiver - The failure of either Party to enforce or insist upon compliance with any of the terms or conditions of this Agreement shall not constitute a waiver or relinquishment of any such terms or conditions, but the same shall be and remain at all times in full force and effect.
- (e) Assignment of Agreement - A Purchase Power Agreement between the Company and the Seller may be transferred and assigned by Seller to any person, firm, or corporation purchasing or leasing and intending to continue the operation of the plant or business which is interconnected under such Agreement, subject to the written approval of Company. A Purchase Power Agreement shall not be transferred and assigned by Seller to any person, firm, or corporation that is party to any other purchase agreement under which a party sells or seeks to sell power to the Company from another Qualifying Facility that is located within one-half mile, as measured from the electrical generating equipment. The Company will grant such approval upon being reasonably satisfied that the assignee will fulfill the terms of the Agreement and if, at the Company's option, a satisfactory guarantee for the payment of any applicable bills is furnished by assignee. However, before such rights and obligations are assigned, the assignee must first obtain necessary approval from all regulatory bodies including, but not limited to, the Commission.
- (f) Notification of Assignment, Transfer or Sale - In the event of an assignment of the rights and obligations accruing to the Seller under this Agreement, or in the event of any contemplated sale, transfer or assignment of the Facility or the Certificate of Public Convenience and Necessity, the Seller shall, in addition to obtaining the approvals hereof, provide a minimum of 30 days prior written notice advising the Company and the Commission of any plans for such an assignment, sale or transfer, or of any accompanying significant changes in the information required by Commission Rule R8-64, R9-65 or R8-66 which are incorporated by reference herein.

## TERMS AND CONDITIONS FOR THE PURCHASE OF ELECTRIC POWER

- (g) Suspension of Sales Under Agreement at the Seller's Request - If the Seller is temporarily unable to produce the electricity contracted for due to physical destruction of, or damage to, his premises, the Company will, upon written request of the Seller, and for a period the Company deems as reasonably required to replace or repair such premises, suspend billing under the Agreement, exclusive of any Monthly Facilities Charges, effective with the beginning of the next sales period.
- (h) Termination of Agreement at the Seller's Request - If the Seller desires to terminate the Agreement, the Company will agree to such termination if all bills for services previously rendered to Seller including any termination or other charges applicable under any Interconnection Agreement, plus any applicable termination charges, have been paid. Termination charges shall consist of any applicable termination charges for premature termination of capacity as set forth in paragraphs 4 and 6 of these Terms and Conditions. The Company may waive the foregoing provision if Company has secured or expects to secure from a new occupant or operator of the premises an Agreement satisfactory to Company for the delivery of electricity to Company for a term not less than the unexpired portion of Seller's Agreement.
- (i) Company's Right to Terminate or Suspend Agreement – The Company, in addition to all other legal remedies, may either terminate the Agreement or suspend purchases of electricity from the Seller based on any of the following: (1) default or breach of the Agreement by the Seller, (2) any fraudulent or unauthorized use of the Company's meter, (3) failure to pay any applicable bills when due and payable, (4) any exceedance of the Contract Capacity or Maximum Annual Energy Production Material Alteration to the Facility without the Company's consent ~~or otherwise delivering energy in excess of the Contract Capacity specified under this Agreement~~, (5) any condition on the Seller's side of the point of delivery actually known by the Company to be, or which the Company reasonably anticipates may be, dangerous to life or property, or (6) Seller fails to deliver energy to Company for six (6) consecutive months. Termination of the Agreement shall be at the Company's sole option and is only appropriate when the Seller either cannot or will not cure its default.

No such termination or suspension, however, will be made by the Company without written notice delivered to the Seller, personally or by mail, stating what in particular in the Agreement has been violated, except that no notice need to be given in instances set forth in 1(i)(2) or 1(i)(5) above. Company shall give Seller thirty (30) calendar days prior written notice before suspending or terminating the Agreement pursuant to provisions 1(i)(1) and 1(i)(3)-(4). Company shall give Seller five (5) calendar days prior written notice before suspending or terminating the Agreement pursuant to provision 1(i)(6).

Failure of the Company to terminate the Agreement or to suspend the purchase of electricity at any time after the occurrence of grounds therefor, or to resort to any other legal remedy or to exercise any one or more of such alternative remedies, shall not waive or in any manner affect the Company's right later to resort to any one or more of such rights or remedies on account of any such ground then existing or which may subsequently occur.

Any suspension of the purchase of electricity by the Company or termination of the Agreement upon any authorized grounds shall in no way operate to relieve the Seller of Seller's liability to compensate Company for services and/or facilities supplied, nor shall it relieve the Seller (1) of the Seller's liability for the payment of minimum monthly charges during the period of suspension, nor (2) of the Seller's liability for damages, if the Agreement has been terminated, in the amount of (a) the minimum monthly charges which would have been payable during the unexpired term of the

**TERMS AND CONDITIONS FOR THE PURCHASE OF ELECTRIC POWER**

Agreement plus (b) the Early Contract Termination charge as set forth in these Terms and Conditions.

**2. CONDITIONS OF SERVICE**

- (a) The Company is not obligated to purchase electricity from the Seller unless and until: (1) the Company's form of Purchase Power Agreement is executed by the Seller and accepted by the Company; (2) in cases where it is necessary to cross private property to accept delivery of electricity from the Seller, the Seller conveys or causes to be conveyed to the Company, without cost to Company, a right of way easement, satisfactory to the Company, across such private property which will provide for the construction, maintenance, and operation of the Company's lines and facilities, necessary to receive electricity from the Seller; provided, however, in the absence of a formal conveyance, the Company nevertheless, shall be vested with an easement over the Seller's premises authorizing it to do all things necessary including the construction, maintenance, and operation of its lines and facilities for such purpose; and (3) any inspection certificates or permits that may be required by law in the local area are furnished to the Company. Where not required by law, an inspection by a Company-approved inspector shall be made at the Seller's expense. In the event the Seller is unable to secure such necessary rights of way, the Seller shall reimburse the Company for all costs the Company may incur for the securing of such rights of way.

The obligation of the Company in regard to service under the Agreement are dependent upon the Company securing and retaining all necessary rights-of-way, privileges, franchises, and permits, for such service. The Company shall not be liable to any Seller in the event the Company is delayed or prevented from purchasing power by the Company failure to secure and retain such rights-of-way, privileges, franchises, and permits.

- (b) The Seller shall operate its Facility in compliance with all: (i) System Operator Instructions provided by the Company, including any Energy Storage Protocols ~~provided~~ approved by the Commission, if applicable; (ii) applicable operating guidelines established by the North American Electric Reliability Corporation (“NERC”); and (iii) the SERC Reliability Corporation (“SERC”) or any successor thereto.
- (c) The Seller shall submit an Interconnection Request as set forth in the North Carolina Interconnection Procedures, Forms and Agreements for State-Jurisdictional Generation Interconnections. The Company shall not be required to install facilities to support interconnection of the Seller's generation or execute the Purchase Power Agreement until the Seller has signed an Interconnection Agreement as set forth in the North Carolina Interconnection Procedures, Forms and Agreements for State-Jurisdictional Generation Interconnections, as may be required by the Company.
- (d) If electricity is received through lines which cross the lands of the United States of America, a state, or any agency or subdivision of the United States of America or of a state, the Company shall have the right, upon 30 days' written notice, to discontinue receiving electricity from any Seller or Sellers interconnected to such lines, if and when (1) the Company is required by governmental authority to incur expenses in the relocation or the reconstruction underground of any portion of said lines, unless the Company is reimbursed for such expense by the Sellers or customers connected thereto, or (2) the right of the Company to maintain and operate said lines is terminated, revoked, or denied by governmental authority for any reason.

**3. DEFINITIONS**

North Carolina Third Proposed Revised Leaf No. 300  
Effective  
NCUC Docket No. E-100 Sub 158  
Order dated

## TERMS AND CONDITIONS FOR THE PURCHASE OF ELECTRIC POWER

- (a) Auxiliary Load: The term “Auxiliary Load” shall mean power used to operate auxiliary equipment in the Facility necessary for power generation (such as pumps, blowers, fuel preparation machinery, and exciters).
- (b) “Company's conductors" shall mean the Company's wires extending from the point of connection with the Company’s existing electric system to the point of delivery.
- (c) “Energy Storage Protocol” shall have the meaning specified in Purchase Power Agreement.
- (d) “Facility” shall have the meaning specified in the Purchase Power Agreement.
- (e) “interconnection” shall mean the connection of the Company’s conductors to the Seller's conductors.

~~(f) “Material Alteration” as used in this Agreement shall mean a modification to the Facility which renders the Facility description specified in this Agreement inaccurate in any material sense as determined by Company in a commercially reasonable manner including, without limitation, (i) the addition of a Storage Resource; (ii) a modification which results in an increase to the Contract Capacity, Nameplate Capacity (in AC or DC), generating capacity (or similar term used in the Agreement) or the estimated annual energy production of the Facility (the “Existing Capacity”), or (iii) a modification which results in a decrease to the Existing Capacity by more than five (5) percent. Notwithstanding the foregoing, the repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%) shall not be considered a Material Alteration. “Maximum Annual Energy Production” shall be calculated as follows:~~

$$\text{[Nameplate Capacity} \times 8760 \times .30] \times 1.10$$

~~(f)~~

- (g) Nameplate Capacity: The term “Nameplate Capacity” shall mean the manufacturer’s kW<sub>AC</sub> nameplate rated output capability of the Facility as measured at the delivery point specified in AC. For multi-unit generator facilities, the “Nameplate Capacity” of the Facility shall be the sum of the individual manufacturer’s kW<sub>AC</sub> nameplate rated output capabilities of the generators. ~~The Nameplate Capacity shall also include the DC rating of the Facility.~~ For inverted-based generating facilities, the “Nameplate Capacity” shall be the manufacturer’s rated kW<sub>AC</sub> output on the inverters.
- (h) “Prudent Utility Practice” means those practices, methods, equipment, specifications, standards of safety, and performance, as the same may change from time to time, as are commonly used in the construction, interconnection, operation, and maintenance of electric power facilities, inclusive of delivery, transmission, and generation facilities and ancillaries, which in the exercise of good judgment and in light of the facts known at the time of the decision being made and activity being performed are considered: (i) good, safe, and prudent practices; (ii) are in accordance with generally accepted standards of safety, performance, dependability, efficiency, and economy in the United States; (iii) are in accordance with generally accepted standards of professional care, skill, diligence, and competence in the United States; and, (iv) are in compliance with applicable regulatory requirements and/or reliability standards. Prudent Utility Practices are not intended to



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be limited to the optimum practices, methods or acts to the exclusion of others, but rather are intended to include acceptable practices, methods and acts generally accepted in the energy generation and utility industry.

- (i) "purchase" or "purchase of electricity" shall be construed to refer to the electricity supplied to the Company by the Seller from the Facility.
- (j) "Seller's conductors" shall mean the Seller's wires extending from the point of delivery to the switch box or other point where the Seller's circuits connect for the purpose of supplying the electricity produced by the Seller.

~~(k) "Storage Resource" means battery storage or other energy storage device installed at or connected behind the meter of the Facility.~~

~~(k)~~ (k) "System Operator Instruction" means any order, action, requirement, demand, or direction, from the system operator in accordance with Prudent Utility Practice, and delivered to Seller in a non-discriminatory manner, to operate, manage, and/or otherwise maintain safe and reliable operations of the system, including, without limitation, an order to suspend or interrupt any operational activity due to an emergency condition or force majeure event; provided however, a System Operator Instruction in response to an emergency condition, force majeure event, or operational condition relating specifically to or created by the Facility shall not be deemed or considered discriminatory.

4. CONTRACT CAPACITY

- (a) The Contract Capacity shall be specified in the Purchase Power Agreement and shall not exceed the capacity specified in the Seller's Interconnection Agreement. This term shall mean the maximum continuous electrical output capability expressed on an alternating current basis of the generator(s) at any time, at a power factor of approximately unity, without consuming VARs supplied by Company, as measured at the Point of Delivery and shall be the maximum kW<sub>AC</sub> delivered to the Company during any billing period. The Seller shall not exceed the ~~existing~~ Contract Capacity unless and until the increase has been agreed to in an amendment executed by Company and Seller and Seller's facilities have been upgraded to accept the actual or requested increase as may be required by Company in its commercially reasonable discretion.
- (b) The Seller shall not change the Contract Capacity, or the Maximum Annual Energy Production, ~~contracted estimated annual energy production~~ without adequate notice to the Company, and without receiving the Company's prior written consent, and if such unauthorized increase causes loss of or damage to the Company's facilities, the cost of making good such loss or repairing such damage shall be paid by the Seller.
- (c) The Company may require that a new Contract Capacity be determined when it reasonably appears that the capacity of the Seller's generating facility or annual energy production will deviate from contracted or established levels for any reason, including, but not limited to, a change in water flow, steam supply, or fuel supply.
- (d) The Seller may apply to the Company to increase the Contract Capacity during the Contract Period and, upon approval by Company, and an amendment to implement the change has been executed by the Company and the Seller, future Monthly delivered capacities shall not exceed the revised Contract Capacity. If such increase in Contract Capacity results in additional costs associated with redesign or a resizing of Company's facilities, such additional costs to the Seller shall be determined in accordance with the Interconnection Agreement.

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~~(e) Any Material Alteration to the Facility, including without limitation, an increase in the Existing Capacity, a decrease in the Existing Capacity by more than five (5) percent or the addition of energy storage capability shall require the prior written consent of the Company, which may be withheld in the Company's sole discretion, and shall not be effective until memorialized in an amendment executed by the Company and the Seller.~~

5. MAXIMUM ESTIMATED ANNUAL ENERGY PRODUCTION

The ~~estimated annual energy production from the Facility specified in the Purchase Power Agreement shall be the estimated~~ total annual kilowatt-hours registered or computed by or from the Company's metering facilities for each time period during a continuous 12-month interval shall not exceed the Maximum Annual Energy Production without the express written consent of Company.

6. EARLY CONTRACT TERMINATION

(a) Early Contract Termination - If the Seller terminates the Agreement or the Agreement is terminated by the Company as permitted in Section 1(i) prior to the expiration of the initial (or extended) term of the Purchase Agreement, the following payment shall be made to the Company by the Seller:

The Seller shall pay to Company the total Energy and/or Capacity credits received in excess of the sum of what would have been received under the Variable Rate for Energy and/or Capacity Credits applicable at the initial term of the contract period and as updated every two years, plus interest. The interest should be the weighted average rate for new debt issued by the Company in the calendar year previous to that in which the Agreement was commenced.

7. CONTRACT RENEWAL

This Agreement shall be subject to renewal for subsequent term(s) at the option of the Company on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the Company's then avoided cost rates and other relevant factors, or (2) set by arbitration.

8. QUALITY OF ENERGY RECEIVED

- (a) The Seller has full responsibility for the routine maintenance of its generating and protective equipment to ensure that reliable, utility grade electric energy is being delivered to the Company.
- (b) The Facility shall be operated in such a manner as to generate reactive power as may be reasonably necessary to maintain voltage levels and reactive area support as specified by the Company. Any operating requirement is subject to modification or revision if warranted by future changes in the distribution or transmission circuit conditions.
- (c) The Seller may operate direct current generators in parallel with the Company through a synchronous inverter. The inverter installation shall be designed such that a utility system interruption will result in the removal of the inverter infeed into the Company's system. Harmonics generated by a DC generator-inverter combination must not adversely affect the Company's supply of electric service to, or the use of electric service by the Company's other customers, and any correction thereof is the full responsibility of the Seller.
- (d) In the event the Company determines, based on calculations, studies, analyses, monitoring, measurement or observation, that the output of the Facility will cause or is causing the Company to be unable to provide proper voltage levels to its customers, the Seller shall be required to comply with a voltage schedule and/or reactive power output schedule as prescribed by the Company.



## TERMS AND CONDITIONS FOR THE PURCHASE OF ELECTRIC POWER

~~(e) All Material Alterations to the Facility shall require the prior written consent from the Company, and the Seller shall provide the Company written notification of any requested changes to the Facility, support equipment such as inverters, or interconnection facilities as soon as reasonably possible to allow the Company adequate time to review such requested changes to ensure continued safe interconnection prior to implementation.~~

~~(f)~~(e) Failure of the Seller to comply with either (a), (b), (c), (d) or (e) above will constitute grounds for the Company to cease parallel operation with the Seller's generation equipment and constitute grounds for termination or suspension of the Agreement as set forth under paragraph 1, above.

9. BILLING

- (a) Meters will be read and bills rendered monthly. Readings are taken each month at intervals of approximately thirty (30) days.
- (b) If Company is unable to read its purchase meter for any reason, the Seller's production may be estimated by Company on the basis of Seller's production during the most recent preceding billing period for which readings were obtained, unless some unusual condition is known to exist. A bill or payment rendered on the basis of such estimate shall be as valid as if made from actual meter readings.
- (c) The term "Month" or "Monthly", as used in Company's Schedules and Riders, refers to the period of time between the regular meter readings by the Company. Bills rendered for periods of less than 25 or more than 35 days as a result of rerouting of the Seller's account, and all initial and final bills rendered on a Seller's account will be prorated on the basis of a normal 30-day billing period.
- (d) Payments for capacity and/or energy will be made to the Seller based on the rate schedule stated in the Purchase Power Agreement.
- (e) The Company reserves the right to set off against any amounts due from the Company to the Seller, any amounts which are due from the Seller to the Company, including, but not limited to, unpaid charges pursuant to the Interconnection Agreement or past due balances on any accounts Seller has with Company for other services.

10. RECORDS

In addition to the regular meter readings to be taken monthly for billing purposes, Company may require additional meter readings, records, transfer of information, etc. as may be agreed upon by the Parties. The Company reserves the right to provide to the Commission or the FERC or any other regulatory body, upon request, information pertaining to this Agreement, including but not limited to: records of the Facility's generation output and the Company's purchases thereof (including copies of monthly statements of power purchases and data from load recorders and telemetering installed at the Facility); copies of this Agreement. The Company will not provide any information developed solely by the Seller and designated by the Seller in writing to be "proprietary" unless required to do so by order of the Commission or the FERC or any other regulatory body or court, in which event, the Company will notify the Seller prior to supplying the proprietary information.

The Seller shall provide to the Company, on a monthly basis within ten (10) days of the meter reading date and in form to be mutually agreed upon by the Parties, information on the Facility's fuel costs (coal, oil natural gas, supplemental firing, etc.), if any, for the power delivered to the Company during the preceding month's billing period.

## TERMS AND CONDITIONS FOR THE PURCHASE OF ELECTRIC POWER

11. METER STOPPAGE OR ERROR

In the event a meter fails to register accurately within the allowable limits established by the state regulatory body having jurisdiction, the Company will adjust the measured energy for the period of time the meter was shown to be in error, and shall, as provided in the rules and regulations of the state regulatory body having jurisdiction, pay to the Seller, or the Seller shall refund to the Company, the difference between the amount billed and the estimated amount which would have been billed had the meter accurately registered the kilowatt hours provided by the Seller. No part of any minimum service charge shall be refunded.

12. POINT OF DELIVERY

The point of delivery is the point where the Company's conductors are, or are to be, connected to the Seller's conductors. The Seller shall do all things necessary to bring its conductors to such point of delivery for connection to the Company's conductors, and shall maintain said conductors in good order at all times. If the Seller chooses to deliver power to the Company through a point of delivery where Seller presently receives power from Company, then the point of delivery for the purchase of generation shall be the same point as the point of delivery for electric service.

13. INTERCONNECTION FACILITIES

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

- (a) By Company: The Company shall install, own, operate, maintain, and otherwise furnish all lines and equipment located on its side of the point of delivery to permit parallel operation of the Seller's facilities with the Company's system. It shall also install and own the necessary metering equipment, and meter transformers, where necessary, for measuring the electricity delivered to the Company, though such meter may be located on the Seller's side of the point of delivery. Interconnection facilities, installed by either Company or the Seller, solely for such purpose, include, but are not limited to connection, line extension, transformation, switching equipment, protective relaying, metering, telemetering, communications, and appropriate safety equipment.

Any interconnection facilities installed by Company necessary to receive power from the Seller shall be considered Interconnection Facilities and shall be provided, if Company finds it practicable, under the following conditions:

- (1) The facilities will be of a kind and type normally used by or acceptable to Company and will be installed at a place and in a manner satisfactory to Company.
- (2) The Seller will pay to Company a Monthly Interconnection Facilities Charge based on 1.0 percent of the estimated original installed cost and rearrangement cost of all facilities, including metering, required to accept interconnection, but not less than \$25 per month. The monthly charge for the Interconnection Facilities to be provided under this Agreement is subject to the rates, Service Regulations and conditions of the Company as the same are now on file with the Commission and may be changed or modified from time to time upon approval by the Commission. Any such changes or modifications, including those which may result in increased charges for the Interconnection Facilities to be provided by the

## TERMS AND CONDITIONS FOR THE PURCHASE OF ELECTRIC POWER

Company, shall be made a part of this Agreement to the same effect as if fully set forth herein.

- (3) If the Company increases its investment in interconnection facilities or other special facilities required by the Seller (including conversion of the Company's primary voltage to a higher voltage), the Monthly Interconnection Facilities Charge for providing the additional facilities will be adjusted at that time. If the Monthly Interconnection Facilities Charge increases, the Seller may terminate the Interconnection Facilities in accordance with the applicable termination paragraph 1 above, or continue Interconnection Facilities under the changed conditions.
  - (4) The Monthly Interconnection Facilities Charge as determined shall continue regardless of the term of the Agreement until Seller no longer has need for such facilities. In the event Seller's interconnection facilities should be discontinued or terminated in whole or in part, such discontinuation or termination should be calculated in accordance with 1, above.
  - (5) The Seller's wiring and appurtenant structures shall provide for the location, connection, and installation of the Company's standard metering equipment or other equipment deemed necessary by the Company for the metering of Seller's electrical output. The Company shall, at its expense, be permitted to install, in the Seller's wiring or equipment, any special metering devices or equipment as deemed necessary for experimental or monitoring purposes.
  - (6) The Company shall furnish and install the Interconnection Facilities no later than the date requested by the Seller for such installation. The Seller's obligation to pay the Interconnection Facilities charges shall begin upon the earlier of (1) completion of the installation but no earlier than the requested in-service date specified in the Interconnection Agreement or (2) the first date when energy is generated and delivered to the Company, and such charges shall apply at all times thereafter during the term of this Agreement, whether or not the Seller is actually supplying electric power to the Company.
- (b) By Seller: The Seller shall install, own, operate, and maintain all lines, and equipment, exclusive of the Company's meter and meter transformers, on the Seller's side of the point of delivery. The Seller will be the owner and have the exclusive control of, and responsibility for, all electricity on the Seller's side of the point of delivery. The Seller must conform to the North Carolina Interconnection Procedures, Forms and Agreements for State-Jurisdictional Generation Interconnections. The Seller's wiring shall be arranged such that all electricity generated for sale can be supplied to one point of delivery and measured by a single meter. The Company's meter may be located on the Seller's side of the point of delivery, and when it is to be so located, the Seller must make suitable provisions in the Seller's wiring, at a place suitable to the Company, for the convenient installation of the type of meter the Company will use. All of the Seller's conductors installed on the Company's side of the meter and not installed in conduit must be readily visible.

The Seller shall install and maintain devices adequate to protect the Seller's equipment against irregularities on the Company's system, including devices to protect against single-phasing. The Seller shall also install and maintain such devices as may be necessary to automatically disconnect the Seller's generating equipment, which is operated in parallel with the Company, when service provided by the Seller is affected by electrical disturbances on the Company's or the Seller's systems, or at any time when the Company's system is de-energized from its prime source.

## TERMS AND CONDITIONS FOR THE PURCHASE OF ELECTRIC POWER

- (c) Access to Premises: The duly authorized agents of the Company shall have the right of ingress and egress to the premises of the Seller at all reasonable hours for the purpose of reading meters, inspecting the Company's wiring and apparatus, changing, exchanging, or repairing the Company's property on the premises of the Seller, or removing such property at the time of or at any time after suspension of purchases or termination of this Agreement.
- (d) Protection: The Seller shall protect the Company's wiring and apparatus on the Seller's premises and shall permit no one but the Company's agents to handle same. In the event of any loss of or damage to such property of the Company caused by or arising out of carelessness, neglect, or misuse by the Seller or the Seller's employees or agents, the cost of making good such loss or repairing such damage shall be paid by the Seller. In cases where the Company's service facilities on the Seller's premises require abnormal maintenance due to the Seller's operation, the Seller shall reimburse Company for such abnormal maintenance cost.

14. CONTINUANCE OF PURCHASES AND LIABILITY THEREFOR

The Parties do not guarantee continuous service but shall use reasonable diligence at all times to provide for uninterrupted acceptance and supply of electricity. Each Party shall at all times use reasonable diligence to provide satisfactory service for the acceptance or supply of electricity, and to remove the cause or causes in the event of failure, interruption, reduction or suspension of service for the acceptance or supply of electricity, but neither Party shall be liable for any loss or damage resulting from such failure, interruption, reduction or suspension of service, nor shall same be a default hereunder, when any interruption of service for the acceptance or supply of electricity is due to any of the following:

- (a) An emergency condition or action due to an adverse condition, event, and/or disturbance on the Company's system, or on any other system directly or indirectly interconnected with it, which requires automatic or manual interruption of the supply of electricity to some customers or areas, or automatic or manual interruption, reduction, or cessation of the acceptance of electricity into Company's electrical system in order to limit the occurrence of or extent or damage of the adverse condition or disturbance to Company's system or capability to reliably provide service in compliance and accordance with prudent practices, regulatory requirements, and/or reliability standards, or to prevent damage to generating or transmission facilities, or to expedite restoration of service, or to effect a reduction in service to compensate for an emergency condition on an interconnected system. An emergency condition or action shall include any circumstance that requires action by the Company to comply with any electric reliability organization or NERC/SERC regulations or standards, including without limitation actions to respond to, prevent, limit, or manage loss or damage to Seller's Facility, reliability impairment, loss or damage to the Company's system, disruption of generation by the Seller, disruption of reliability or service on the Company's system, an abnormal condition on the system, and/or endangerment to human life or safety.
- (b) An event or condition of force majeure, as described below.
- (c) Making necessary adjustments to, changes in, or repairs on the Company lines, substations, and facilities, and in cases where, in its opinion, the continuance of service from the Seller's premises would endanger persons or property.

Seller shall be responsible for promptly taking all actions requested or required by Company to avoid, prevent, or recover from the occurrence and/or imminent occurrence of any emergency condition and

**TERMS AND CONDITIONS FOR THE PURCHASE OF ELECTRIC POWER**

in response to any emergency condition or condition of force majeure, including without limitation installing and operating any equipment necessary to take such actions.

The Seller shall be responsible for insuring the safe operation of his equipment at all times, and will install and maintain, to the Company's satisfaction, the necessary automatic equipment to prevent the back feed of power into, or damage to the Company's de-energized system, and shall be subject to immediate disconnection of its equipment from the Company's system if the Company determines that such equipment is unsafe or adversely affects the Company's transmission/distribution system or service to its other customers.

The Seller assumes responsibility for and shall indemnify, defend, and save the Company harmless against all liability, claims, judgments, losses, costs, and expenses for injury, loss, or damage to persons or property including personal injury or property damage to the Seller or the Seller's employees on account of defective construction, wiring, or equipment, or improper or careless use of electricity, on the Seller's side of the point of delivery.

**15. FORCE MAJEURE**

Circumstances beyond the reasonable control of a Party which solely cause that Party to experience delay or failure in delivering or receiving electricity or in providing continuous service hereunder, including: acts of God; unusually severe weather conditions; earthquake; strikes or other labor difficulties; war; riots; fire; requirements shall be deemed to be "events or conditions of force majeure". It also includes actions or failures to act on the part of governmental authorities (including the adoption or change in any rule or regulation or environmental constraints lawfully imposed by federal, state or local government bodies), but only if such requirements, actions or failures to act prevent or delay performance; or transportation delays or accidents. Events or conditions of force majeure do not include such circumstances which merely affect the cost of operating the Facility.

Neither Party shall be responsible nor liable for any delay or failure in its performance hereunder due solely to events or conditions of force majeure, provided that:

- (a) The affected Party gives the other Party written notice describing the particulars of the event or condition of force majeure, such notice to be provided within forty-eight (48) hours of the determination by the affected Party that an event or condition of force majeure has occurred, but in no event later than thirty (30) days from the date of the occurrence of the event or condition of force majeure;
- (b) The delay or failure of performance is of no longer duration and of no greater scope than is required by the event or condition of force majeure, provided that in no event shall such delay or failure of performance extend beyond a period of twelve (12) months;
- (c) The affected Party uses its best efforts to remedy its inability to perform;
- (d) When the affected Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party prompt written notice to that effect; and,
- (e) The event or condition of force majeure was not caused by or connected with any negligent or intentional acts, errors, or omissions, or failure to comply with any law, rule, regulation, order or ordinance, or any breach or default of this Agreement.

**16. INSURANCE**

The Seller shall obtain and retain, for as long as the generation is interconnected with Company's system, either the applicable home owner's insurance policy with liability coverage of at least



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\$100,000 per occurrence or the applicable comprehensive general liability insurance policy with liability coverage in the amount of at least \$300,000 per occurrence, which protects the Seller from claims for bodily injury and/or property damage. This insurance shall be primary for all purposes. The Seller shall provide certificates evidencing this coverage as required by the Company. The Company reserves the right to refuse to establish, or continue the interconnection of the Seller's generation with Company's system, if such insurance is not in effect.

17. GOVERNMENTAL RESTRICTIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either party or over this Agreement. This Agreement shall not become effective until all required governmental authorizations are obtained. Certification of receipt of all permits and authorizations shall be furnished by the Seller to the Company upon the Company's request. This Agreement shall not become effective unless it and all provisions thereof are authorized and permitted by such governmental agencies without change or conditions.

This Agreement shall at all times be subject to changes by such governmental agencies, and the parties shall be subject to conditions and obligations, as such governmental agencies may, from time to time, direct in the exercise of their jurisdiction, provided no change may be made in rates or in essential terms and conditions of this contract except by agreement of the parties to this contract. Both parties agree to exert their best efforts to comply with all of the applicable rules and regulations of all governmental agencies having control over either party or this Agreement. The parties shall take all reasonable action necessary to secure all required governmental approval of this Agreement in its entirety and without change.

The delivery date, quantity, and type of electricity to be accepted for purchase by the Company, from the Seller, are subject to changes, restrictions, curtailments, or complete suspensions by Company as may be deemed by it to be necessary or advisable (a) on account of any lawful order or regulation of any municipal, State, or Federal government or agency thereof, or order of any court of competent jurisdiction, or (b) on account of any emergency due to war, or catastrophe, all without liability on the part of the Company therefor.