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November 1, 2021

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits
Docket No. E-100, Sub 175

Dear Ms. Dunston:

Enclosed for filing in the above-captioned docket is the Joint Initial Statement for Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies"). Consistent with the Commission's August 13, 2021 *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("Scheduling Order") issued in the above-captioned docket and the October 30, 2020 *Order Granting Continuance and Establishing Reporting Requirements* (*"*Order Granting Continuance*")* issued in Docket No. E-100, Sub 167, the Joint Initial Statement presents for Commission approval the Companies' standard avoided cost rates and contract terms and conditions for qualifying facilities ("QFs") one (1) megawatt and less. As the Commission approved in the Order Granting Continuance, this filing also addresses several issues required by the Commission's April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, issued in Docket No. E-100, Sub 158 pertaining to real-time pricing tariffs; cost increments and decrements to the publicly available combustion turbine cost estimates; the use of other reliability indices, specifically the Equivalent Unplanned Outage Rate metric, to support development of the performance adjustment factor; the extent of backflow at substations; the potential for qualifying facilities to provide ancillary services and appropriate compensation; and the results of an independent technical review of the Astrapé Study solar integration services charge methodology.

The Companies have designated portions of their respective Exhibits 2 and their joint Exhibit 8 to this Joint Initial Statement as confidential and trade secret information. Pursuant to N.C. Gen. Stat. § 132-1.2, the Companies respectfully request that the

Commission protect this data from public disclosure. Exhibit 2 discloses estimated costs to procure additional energy, as well as the projected cost of new utility-owned generation. Public disclosure could hinder the Companies from obtaining the most cost-effective energy and capacity necessary to meet the needs of its customers. Exhibit 8 includes confidential and trade secret information, as well. The Companies will make this information available to other parties pursuant to an appropriate confidentiality agreement.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs, in Docket No. E-100, Sub 175 has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, property addressed to parties of record.

This the 1st day of November, 2021.

Kendrick C. Fentress

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 175

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021	)))))	JOINT INITIAL STATEMENT AND PROPOSED STANDARD AVOIDED COST RATE TARIFFS OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

NOW COME Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") ("the Companies"), pursuant to the Commission's August 13, 2021 *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("2021 Scheduling Order"), and submit the Companies' Joint Initial Statement and Exhibits in support of DEC's and DEP's proposed avoided cost rates, updated Schedule PP tariffs, and standard contract terms and conditions ("Submissions"). The Companies' Submissions set forth their proposed standard offer avoided cost rates for qualifying cogenerators and small power production facilities ("QFs") that are eligible for the Companies' respective Schedule PPs and establish a legally enforceable obligation ("LEO") committing to sell their output to the Companies on or after the date of this filing.

The Companies' Submissions are designed to comply with Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the Federal Energy Regulatory Commission's ("FERC") regulations requiring standard rates for purchases from small QFs under PURPA, as well as North Carolina's biennial standard offer PURPA implementation framework.[1] The Companies' Submissions also comply with the requirements of the Commission's prior avoided cost orders and address directives set forth in the Commission's April 15, 2020 *Order Establishing Standard Rates and Contract Terms For Qualifying Facilities*, issued in Docket No. E-100, Sub 158 ("2018 Sub 158 Order), the Commission's October 30, 2020 *Order Granting Continuance and Establishing Reporting Requirements*, in Docket No. E-100, Sub 167 ("Sub 167 Continuance Order"), and the Commission's most recent *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* issued on August 13, 2021, in Docket No. E-100, Sub 167 ("2020 Sub 167 Order"). As explained in more detail herein, in these past avoided cost orders, the Commission has directed the Companies to address certain additional issues from these past avoided cost proceedings in this Joint Initial Statement.

The Companies have worked diligently throughout 2021 to assess the additional issues as well as to review other inputs and methodologies used to develop their avoided cost rates. The Companies have also engaged with Public Staff and other interested stakeholders regarding standardized and reasonable approaches to avoided cost inputs and assumptions in an effort to reduce the number of contested issues presented in biennial avoided cost proceedings. These significant efforts have been fruitful, and the Companies are optimistic that the number of contested issues for Commission determination can be reduced.

As detailed in this Joint Initial Statement, the Companies' avoided costs have increased since 2020. When weighted based on a generic solar profile, DEC's avoided

[1] As required by 18 C.F.R. 292.302(b)(1)-(3), the Companies file with the Commission their respective forecasted system cost data from which avoided costs may be derived every two years. This information was most recently filed on November 2, 2020, in the 2020 biennial avoided cost proceeding (Docket No. E-100, Sub 167). Accordingly, the Companies are not refiling this information in this proceeding.

cost rates have increased by approximately 21% percent while DEP's avoided cost rates have increased approximately 23%, when compared to the avoided cost rates approved in the *2020 Sub 167 Order*. The primary driver for the increase in proposed avoided cost rates is higher energy rates due to increases in market fuel prices when compared to the 2020 Sub 167 proceedings.

The Companies' Joint Initial Statement supporting the Companies' Submissions and detailing the calculation of these 2021 avoided cost rates follows.

JOINT INITIAL STATEMENT OF DEC AND DEP

I. Introduction and Background

A. Legal Framework for the Companies' Avoided Cost Rates and Standard Offer

Section 210 of PURPA requires the Companies to purchase the output from QFs and to pay them nondiscriminatory rates that are just and reasonable to the Companies' customers and that do not exceed the Companies' incremental cost of alternative energy or "avoided costs."[2] Through PURPA, Congress delegated to this Commission the responsibility of implementing PURPA's "must purchase" requirements, consistently with FERC's PURPA regulations.[3] FERC's PURPA regulations specifically require state regulatory authorities, such as this Commission, to establish standard rates for purchase from smaller QFs with a design capacity of 100 kilowatts (kW) or less and provide States

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[2] *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 3, FERC Stats. & Regs. ¶ 30,128 (1980) ("Order No. 69"). *See generally*, 16 U.S.C.A. § 824a-(3); 18 C.F.R. 292.304(a).

[3] *Order No. 69*, at 7; *see also Policy Statement Regarding Comm'n's Enforcement Role Under Sec. 210 of the Public Utility Regulatory Policies Act of 1978*, 23 FERC ¶ 61,304, 61,644 (1983). On July 16, 2020, the FERC issued Order No. 872, 172 FERC ¶ 61,041 (2020), which approved certain revisions to its regulations implementing Sections 201 and 210 of PURPA. These revised rules became effective December 31, 2020.

the flexibility to establish standard rates for QFs with a design capacity greater than 100 kW.[4]

North Carolina's PURPA implementation framework requires the Commission to implement PURPA through biennial avoided cost proceedings, and, specifically, to approve standard contract avoided cost rates and power purchase agreements to be used by the State's electric public utilities in purchasing energy and capacity from small power producers.[5] Pursuant to recent modifications of the State's PURPA implementation framework enacted by Session Law 2017-192 ("HB 589"), the Companies' standard offer avoided cost rates and contracts are currently available to QFs up to 1,000 kW. HB 589 further provides that eligibility for the standard offer shall prospectively be reduced to a capacity eligibility limit of 100 kW after each electric public utility enters into PPAs with an aggregate new capacity of 100 MWs subsequent to November 15, 2016.[6]

HB 589 also limits the maximum length of fixed-term standard offer rates and contracts to 10 years and refined the calculation of avoided capacity cost rates.[7] Section (b)(3) of N.C. Gen. Stat. § 62-156 now directs that a future capacity need shall only be avoided in a year where the Companies' most recently approved biennial integrated resource plan ("IRP") has identified a projected capacity need to serve system load, and the identified need can be met by the type of QF resource based upon its availability and

[4] *See* 18 C.F.R. 292.304(c).

[5] N.C. Gen. Stat. § 62-156(b).

[6] N.C. Gen. Stat. § 62-156(b)(1). As of the date of this filing, 10 QFs totaling 6.04 MWs have executed standard offer PPAs committing to sell their output to DEC, and 7 QFs totaling 1.498 MWs have executed standard offer PPAs committing to sell their output to DEP under the standard offer rates and terms in effect since November 15, 2016.

[7] *Id.*

reliability of power.[8] Additionally, with respect to the calculation of avoided cost rates, section (b)(2) provides that a determination of the utility's avoided energy costs shall include consideration of the following factors over the term of the PPA: (i) the expected costs of the additional or existing generating capacity that could be displaced, (ii) the expected cost of fuel and other operating expenses of electric energy production that a utility would otherwise incur in generating or purchasing power from another source, and (iii) the expected security of the supply of fuel for the utility's alternative power sources.[9]

HB 589 also evolved the State's solar procurement framework for larger QFs and other renewable generators by reducing the maximum term of fixed price mandatory purchase contracts under PURPA to five years, while also creating new alternative competitive and customer driven programs, such as the Competitive Procurement of Renewable Energy Program ("CPRE"), the large customer directed procurement of renewable energy Green Source Advantage Program, Solar Rebate Program and the Community Solar Program, to add more cost-effective solar to the Companies' systems.[10]

The Commission has implemented the State's revised PURPA implementation framework under HB 589 in the past three avoided cost proceedings in 2016-2017 ("2016 Sub 148 proceeding"), 2018-2019 ("2018 Sub 158 proceeding"), and 2020-2021 ("2020 Sub 167 proceeding").

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[8] N.C. Gen. Stat. § 62-156(b)(3). Exceptions to this IRP-designated first year of capacity need standard include certain hydroelectric QFs and swine and poultry QFs selling under the State's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS"), as further discussed in Section III.a.1 of the Companies' Joint Initial Statement.

[9] N.C. Gen. Stat. § 62-156(b)(2).

[10] *See* N.C. Gen. Stat. § 62-110.8 (establishing the Competitive Procurement of Renewable Energy Program); N.C. Gen. Stat. § 62-159.2 (establishing the large-customer directed renewable energy procurement program); N.C. Gen. Stat. § 62-155(f) (establishing the solar rebate program); and N.C. Gen. Stat. § 62-126.8 (establishing the community solar energy facilities program).

B. Continued QF Development in North Carolina

While HB 589 significantly revised the State's PURPA implementation framework, robust solar and other QF development has continued in North Carolina, primarily through CPRE and the other alternative customer-directed programs enacted in HB 589. As shown in Figure 1, approximately 5,160 MWs of solar and 263 MWs of non-solar capacity are either installed or under contract, which reflects an increase of 48% since 2018. Significant additional solar capacity exceeding 4,419 MWs also continues to be developed in the State.[11]

Figure 1

DE Carolinas:		
On-Line and Under Contract	**MW**	**SubTotal**
Biofuels	63	
Hydroelectric	32	
Solar	765	
Wind	0	
Other	0	
	859	**859**
Under Contract, but not On-line	**MW**	**SubTotal**
Solar	1101	
	1101	**1961**
Pending, Not Under Contract, Not On-Line	**MW**	**SubTotal**
Solar	735	
Battery	2	
DEC Total	**737**	**2698**

DE Progress:		
On-Line and Under Contract	**MW**	**SubTotal**
Biofuels	147	
Hydroelectric	16	
Solar	2588	
Wind	0	
Other	5	
	2756	**2756**
Under Contract, but not On-line	**MW**	**SubTotal**
Solar	706	
	706	**3462**
Pending, Not Under Contract, Not On-Line	**MW**	**SubTotal**
Solar	3684	
Battery	117	
DEP Total	**3801**	**7263**

This robust development of new solar QFs and other renewable energy resources has continued during an extended period of historically low avoided cost rates over the past

[11] Reflects all pending utility-scale solar Interconnections Requests in the North Carolina and FERC-jurisdictional interconnection queues.

decade. In this proceeding, the Companies' avoided costs have increased which may further encourage development of new QFs.

C. Issues from Docket Nos. E-100, Sub 158 and Sub 167

In the 2018 Sub 158 proceeding, the Commission continued its implementation of the revised PURPA standard offer framework enacted by HB 589. The *2018 Sub 158 Order* directed the Companies and Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" or "Dominion")(collectively, the "Utilities"), to develop additional refinements to their standard offer avoided capacity and energy rates and terms and conditions for purchasing QF power for consideration in the then next avoided cost proceeding in the 2020 Sub 167 proceeding. Specifically, the Commission directed the Utilities to address the following issues in their November 2, 2020 filings in the 2020 Sub 167 proceeding:

- Real-time pricing tariffs;
- Cost increments and decrements to the publicly available combustion turbine cost estimates;
- The use of other reliability indices, specifically the Equivalent Unplanned Outage Rate ("EUOR") metric, to support development of the performance adjustment factor ("PAF");
- The extent of backflow at substations;
- The potential for qualifying facilities ("QFs") to provide ancillary services and appropriate compensation; and
- The results of an independent technical review of the Astrapé Study solar integration services charge ("SISC") methodology.

("Sub 158 Additional Issues").

Although the Companies initially intended to address all of the Sub 158 Additional Issues in their Joint Initial Statement in the 2020 Sub 167 proceeding, a number of factors complicated their ability to do so. Therefore, on October 20, 2020, they and DENC filed: (i) a notification that they would be filing a streamlined Joint Initial Statement ("JIS") to comply with PURPA and N.C. Gen. Stat. § 62-156 on November 2, 2020 and (ii) a request to continue the requirements to address the Sub 158 Additional Issues and complete certain stakeholder coordination until November 1, 2021.[12] The Utilities also noted that they required additional time to review FERC Order No. 872 to determine whether it impacted their upcoming avoided cost proposals. Thus, the Utilities proposed in their *Sub 167 Continuance Motion* to update their avoided cost rates to meet the requirements of N.C. Gen. Stat. § 62-156(b) in the 2020 Sub 167 proceeding and to develop their responses to the Sub 158 Additional Issues, in some cases, with stakeholders, for filing in a subsequent avoided cost proceeding that commenced November 1, 2021.[13]

The Commission's *Order Granting Continuance and Establishing Reporting Requirements*, allowed the Utilities' request and further directed the Companies "to make significant effort to address all of the Sub 158 Additional Issues, resolving these issues or otherwise achieving consensus with interested stakeholders before the commencement of the next biennial avoided cost proceeding."[14] The Commission also specifically accepted the Companies' commitment to transparency, to providing an update once the solar integration services charge ("SISC") technical review committee ("TRC") is selected, and to scheduling a stakeholder meeting in Summer 2021 to discuss the report of the TRC and results from the TRC's work.[15] The Commission encouraged the Utilities and interested parties to use the additional time to reach consensus to the maximum extent possible on all

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[12] *See Notification of Intended Compliance with N.C. Gen. Stat. § 62-156(b), Request for Continuance of Compliance with Certain 2020 Filing Requirements and Request to Prospectively Modify Timing of Biennial Proceedings*, Docket No. E-100, Sub 167 (filed Oct. 20, 2020) ("*Sub 167 Continuance Motion*").

[13] *Id.*

[14] Docket No. E-100, Sub 167, at 3 (Oct. 30, 2020) ("*Sub 167 Continuance Order*").

[15] *Id.*

of the issues to be presented to the Commission in the November 1, 2021 filing.[16] Finally, the Commission directed the Utilities to file by December 7, 2020 a proposal and timeline showing how they intend to address each unresolved item and a status update every 45 days thereafter.[17]

The 2020 Sub 167 proceedings were streamlined consistent with the *Sub 167 Continuance Order*. In its *2020 Sub 167 Order*, however, the Commission identified additional issues for the Companies to address in their November 1, 2021 JIS in Docket No. E-100, Sub 175. The Commission directed the Companies to specifically address: (i) the continuation of the PAF to be applied to avoided capacity rates for hydroelectric ("hydro") QFs one MW and less; (ii) avoided hedging costs; and (iii) the inclusion of start costs for production cost modeling used to determine avoided energy costs.[18] As provided for herein, the Companies have addressed the Sub 158 Additional Issues and these issues, as directed in the Commission's *2020 Sub 167 Order*.

D. <u>The Companies' Stakeholder Engagement</u>

As outlined in the Companies' joint 45-day progress reports filed with the Commission in Docket No. E-100, Sub 167[19] over the past year, the Companies have initiated numerous, robust discussions of the Sub 158 Additional Issues and other avoided cost issues with the Public Staff and other stakeholders prior to filing this JIS.[20] The

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[16] *Id.*

[17] *Id.*

[18] *2020 Sub 167 Order*, at 40, 60 (Ordering Paragraph 11).

[19] For purposes of a complete record in this docket, the Companies incorporate the 45-day progress reports that they filed in Docket No. E-100, Sub 167 by reference in this JIS.

[20] *Eighth Joint 45-Day Progress Report of Duke Energy Carolinas, LLC And Duke Energy Progress, LLC*, Docket No. E-100, Sub 167 (filed Oct. 22, 2021).

Companies have also used the additional time allowed by the *Sub 167 Continuance Order* to develop reasonable and repeatable avoided cost methodologies that both reflect the current economic and regulatory circumstances and minimize, to the greatest extent possible, the potential for lengthy, contentious avoided cost proceedings in the future. Specifically, as described in more detail in the 45-day progress reports and herein, the Companies have engaged with the Public Staff over the past several months to develop consensus on reasonable, standardized, and repeatable methodologies on avoided cost issues that are typically contentious, such as the appropriate fuel forecasts, avoided CT costs and cost adjustments, avoidable hedging costs, line losses and the PAF. The Companies appreciate the opportunity to work with the Public Staff[21] to develop consensus on these previously contentious issues. These discussions have resulted in a reasonable and appropriate methodology to calculate the PAF for purposes of this proceeding and future avoided cost proceedings. If the Companies' avoided cost methodologies used in this filing are approved, they intend to continue using them in future avoided cost proceedings, updated with the then-current inputs.

The Companies also used the additional time to engage with other stakeholders, as directed by the Commission. In addition to hosting a virtual stakeholder meeting on the technical review of the SISC methodology on September 2, 2021, the Companies convened virtual stakeholder meetings on August 19, 2021, September 20, 2021, and October 5, 2021.[22] Stakeholders attending these meetings included representatives from Southern

[21] The Companies also engaged with Dominion towards standardizing a number of these avoided cost inputs between the Utilities.

[22] Topics addressed in these meetings included Proposed CT cost calculation; PAF; CT cost calculations; line losses (August 19); QFs' abilities to potentially provide ancillary services and appropriate compensation; FERC Order No. 872; as-available avoided energy rates (September 20). The Companies' presentations were

Alliance for Clean Energy ("SACE"), North Carolina Sustainable Energy Association ("NCSEA"), Carolina Industrial Group for Fair Utility Rates ("CIGFUR"), Carolinas Clean Energy Business Alliance ("CCEBA"), and the Public Staff. For the October 5, 2021 meeting, the Companies requested presentations from stakeholders on issues they would like to discuss further. Representatives from SACE and NCSEA provided general comments on areas of concern and issues for potential further discussion. The Companies believe the meetings were productive. As noted in their recent 45-day progress reports, the Companies are also willing to continue to engage with these stakeholders after the Companies' JIS and Submissions are filed.

II. Overview of Exhibits Supporting Initial Statement Filing

As required by Ordering Paragraph three (3) of the *2021 Scheduling Order*, DEC and DEP each submit for approval proposed standard avoided cost rates for qualifying cogeneration and small power production facilities, as further discussed and supported herein.

- DEC Exhibit 1 presents proposed clean and redlined copies of DEC's Purchased Power Schedule PP.
- Confidential DEC Exhibit 2 presents the supporting calculations for the energy and capacity credits, inflation rates, and discount rates used to derive DEC's proposed avoided capacity and energy cost rates. Information included in Exhibit 2 is designated Confidential and is being filed under seal.
- DEC Exhibit 3 presents clean and redlined copies of DEC's proposed Standard PPA available to QFs eligible for Schedule PP.

previously provided to the Commission in the Companies seventh and eighth 45-day Progress Reports filed in Docket No. E-100, Sub 167.

- DEC Exhibit 4 presents clean and redlined copies of DEC's proposed Terms and Conditions for the Purchase of Electric Power ("Terms and Conditions").
- DEC Exhibit 5 presents DEC's annualized rates.
- DEC/DEP Exhibit 6 presents clean and redlined copies of the Companies' updated Notice of Commitment Form for QFs eligible for Schedule PP.
- DEC/DEP Exhibit 7 presents clean and redlined copies of the Companies' Notice of Commitment Form for QFs larger than 1 MW in size.

DEP Exhibits 1-5 present the same information for DEP as described above for DEC, while the Notice of Commitment Forms presented in Exhibit 6 and Exhibit 7 are applicable to both Companies. The Companies further address the updates presented in these Exhibits to this Joint Initial Statement in Parts III through VIII that follow.

The Companies are also filing certain studies and supporting documents to be included in the record in this proceeding as support for their proposed standard avoided cost rates and corresponding contracting documents:

- DEC/DEP Confidential Exhibit 8 provides additional technical support for certain inputs to DEC's and DEP's avoided energy and capacity cost calculations.
- DEC/DEP Exhibit 9 shows the geographical location of substations with backflow in North and South Carolina as further addressed in the Section III.b.3 of the Companies' Initial Statement.
- DEC/DEP Exhibit 10 is the Technical Review Committee's Review of Duke Energy's SISC, prepared by The Brattle Group on behalf of the SISC TRC.

- DEC/DEP Exhibit 11 is the Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge Study, prepared by Astrapé Consulting (the "2021 Astrapé SISC Study").

Finally, the Companies are presenting the published New ESS retrofit avoided cost rates to be available to QFs that commit to retrofit their existing generating facility to co-locate an energy storage system ("ESS"), as recently addressed in the Companies' September 29, 2021 Compliance Filing in Docket Nos. E-100, Sub 101 and E-100, Sub 158 ("ESS Retrofit Compliance Filing").

- DEC Exhibit 12 presents the published New ESS retrofit avoided cost rates to be made available to ESS Retrofit QFs until November 1, 2023.
- DEP Exhibit 12 presents the same materials for DEP.

III. Long-Term Fixed Avoided Cost Rate Methodology and Calculations

a. Peaker Methodology

The Companies have each used the component or "peaker" methodology to develop their avoided capacity and energy costs for QFs committing to deliver their full capacity and energy output for a specified fixed future term. The Commission has consistently approved the Companies' continued use of the "peaker method" as reasonable and appropriate for deriving DEC's and DEP's forecasted avoided costs in the 2020 Sub 167 proceeding and a number of prior biennial avoided cost proceedings.[23] As recognized in these prior avoided cost proceedings, the peaker method is "generally accepted throughout the electric industry to calculate avoided costs based upon the cost of a peaker (i.e., a

[23] *See 2020 Sub 167 Order*, at 60 (Ordering Paragraph 8); *2018 Sub 158 Order*, at 134 (Ordering Paragraph 10); *see also Order Setting Avoided Cost Inputs,* Docket No. E-100, Sub 140, at 8 (Finding of Fact 6) (issued Dec. 31, 2014) ("*Phase I Sub 140 Order").*

combustion turbine), plus the marginal running costs of the system (i.e., the highest marginal cost in each hour)."[24] In particular, the peaker methodology was recognized as an acceptable method for determining avoided cost in the widely relied-upon *PURPA Title II Compliance Manual* published by the National Association of Regulatory Utility Commissioners, the Edison Electric Institute, and other industry organizations.[25] The Companies' use of the peaker method has also been approved by the Public Service Commission of South Carolina.[26]

b. <u>Avoided Capacity Cost Calculations</u>

In the *2020 Sub 167 Order*, the Commission directed the Utilities to "continue to calculate avoided capacity costs using the peaker method and include a levelized payment for capacity over the term of the contract that provides a payment for capacity in years that the utility's IRP forecast period demonstrates a capacity need."[27] The Commission also determined that the Companies appropriately calculated their avoided capacity rates consistent with N.C. Gen. Stat. § 62-156(b)(3) and that the first years of avoidable undesignated capacity need identified for DEC and DEP, respectively, were "appropriate"

[24] *See Phase I Sub 140 Order,* at 30 (explaining that the Commission "has long approved the use of the peaker method for the purpose of establishing avoided costs and has repeatedly held that, according to the theory underlying the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided cost."). Applying the peaker method, the cost of peaking capacity is utilized as the cost basis for the capacity credits, and energy credits are calculated by simulating DEC's and DEP's respective system operations with and without 100 MWs of no cost energy in each hour and determining the energy cost difference between the simulations."

[25] Robert Burns & Ken Rose, "PURPA Title II Compliance Manual" at 35 (March 2014) ("PURPA Title II Compliance Manual"), available online at: https://www.naruc.org/our-programs/resources/) (last visited Aug. 11, 2019); see also, "PURPA Title II Compliance Manual 2.0" at 72 (July 2021), available online at: https://pubs.naruc.org/pub/47AD30DC-1866-DAAC-99FB-975A60906D6B) (last visited Oct. 30, 2021).

[26] *Amended Order Approving Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Standard Offer Tariffs, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, and Commitment to Sell Forms*, Order No. 2019-881(A), Docket Nos. 2019-185-E & 2019-186-E (S.C.P.S.C. Jan. 2, 2020).

[27] *2020 Sub 167 Order*, at 60 (Ordering Paragraph 8).

and determined consistent with the Commission's *2018 Sub 158 Order* and the Companies respective 2020 IRPs.[28]

1. First Year of Avoidable Capacity Need

DEC and DEP have developed their avoided capacity rates consistent with the methodology that they used in the 2018 Sub 158 and 2020 Sub 167 proceedings and that the Commission most recently approved in the *2020 Sub 167 Order* as appropriately implementing N.C. Gen. Stat. § 62-156(b)(3).

As background, the Commission's *2018 Sub 158 Order* directed the Companies to include in future IRPs a clear statement identifying each utility's first year of avoidable capacity need to be used in determining their respective avoided capacity costs.[29] The Companies followed this directive, identifying each utility's next year of avoidable undesignated capacity in their 2020 IRPs and using those dates to determine avoided capacity costs in the 2020 Sub 167 proceeding.

The current 2021 Sub 175 proceeding presents a unique procedural posture in that it is taking place in an odd calendar year, before Commission approval of the Companies' 2020 IRPs, without a 2021 update to their IRPs, and before the Companies have had an opportunity to file their next biennial IRPs in 2022. In other words, the Companies last filed their identified first resource needs with the Commission in September 2020 as part of their respective 2020 IRPs. Because the Commission's June 29, 2021 *Order Waiving in Part Rule R8-60(h)(2) and Giving Notice of Additional Proceedings,* in Docket No. E-100, Sub 165 also waived the Companies' obligation to file updated 2021 IRPs under Rule

[28] *Id.,* at 6 (Finding of Fact 6).

[29] *Id.,* at 10 (Findings of Fact 19, 22).

R8-60(h)(2), the Companies have not previously filed any update to their first resource needs in 2021. Accordingly, DEC/DEP Exhibit 8 presents DEC's and DEP's updated first years of undesignated capacity need.

Most notably, DEC's updated first year of avoidable undesignated capacity need reflects the additional approximately 175 MWs of designated capacity that will be added to the DEC system through the Integrated Volt/Var Control ("IVVC") program approved by the Commission in March 2021.[30] Taking into account the addition of this Commission-approved designated capacity, which is new to the DEC system since the filing of its 2020 IRP, DEC's next avoidable undesignated capacity need now occurs in 2028.[31]

DEP's next avoidable undesignated capacity need is unchanged from the DEP 2020 IRP and occurs in 2024. Compared to the standard offer avoided cost rates approved in the 2020 Sub 167 proceeding, DEC's first year of avoidable capacity need shifted outward from 2026 to 2028, while DEP's first year of avoidable capacity need remained the same at 2024. For DEP, due to passage of time, this represents an earlier capacity need than used in the prior 2020 Sub 167 avoided cost rates.

Also consistent with the *2020 Sub 167 Order* and N.C. Gen. Stat. § 62-156(b)(3), DEC and DEP have included alternative avoided capacity rate calculations in their Schedule PP rates that recognize that certain QFs fueled by swine waste, poultry waste, and certain existing hydro power QFs less than 5 MWs, are assigned immediate capacity value.[32]

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[30] The IVVC program is part of DEC's Grid Improvement Plan ("GIP"), which was approved by the Commission by *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice,* issued March 31, 2021, in Docket No. E-7, Sub 1214.

[31] DEC/DEP Exhibit 9.

[32] *2020 Sub 167 Order*, at 6 (Finding of Fact 7), 17, 60 (Ordering Paragraph 8). In its *2018 Sub 158 Order*, the Commission found that the clear intent of the General Assembly is to treat swine and poultry waste QF

2. Avoided CT Unit Cost Assumptions

Consistent with the Commission's directives in prior avoided cost proceedings, the *2018 Sub 158 Order* concluded that the Utilities should use the installed cost of a CT unit derived from publicly available industry sources, such as the United States Energy Information Administration ("U.S. EIA"), tailored to adapt such information to the Carolinas for purposes of calculating their avoided capacity costs.[33] The *2018 Sub 158 Order* additionally directed, as one of the Sub 158 Additional Issues, that the Utilities should evaluate and apply cost increments and decrements to the publicly available CT cost estimates, including the use of brownfield sites, existing infrastructure, decrements for electrical and natural gas connections, and other balance of plant items, to the extent it is likely that this existing infrastructure is used to meet future capacity additions by the utility.[34] In this proceeding, DEC and DEP worked with the Public Staff and Dominion to develop the methodology for calculating CT cost estimates. The parties arrived at a consensus approach to streamline the determination of the avoided CT capacity cost. The resulting process fairly values the avoided capacity cost for QFs while ensuring customers do not overpay for capacity.

Pursuant to the Commission's directive in the *2018 Sub 158 Order*, the Companies considered the use of brownfield sites for calculating the avoided capacity cost.[35] Resource needs in the Companies' IRPs are largely driven by coal unit retirements, which present

resources and 5 MWs or less legacy hydro QF resources differently from other QFs in regard to valuing their ability to avoid the Utilities' projected capacity needs to serve system load during the future IRP planning period.

[33]*See 2018 Sub 158 Order*, at 32-33.

[34] *Id.*, at 33, 134 (Ordering Paragraph 9).

[35] *Id.*

opportunities to construct new generation at either brownfield or greenfield sites. While construction of replacement generation at brownfield sites could potentially offer higher cost savings (thereby lowering avoided CT cost), the Companies expect that any savings would be very site-specific. In contrast, calculating CT costs using a greenfield economies of scale adjustment reflects the generic nature of the avoided CT under the peaker method and also results in a smaller adjustment to the publicly available CT capacity cost which benefits the QF. For these reasons, using a standardized greenfield economies of scale adjustment for the purpose of calculating avoided CT costs is more appropriate at this time. This approach is also consistent with the methodology approved by the Commission in its *2020 Sub 167 Order*.[36]

More specifically, the greenfield economies of scale methodology uses the avoided capacity cost based upon the U.S. EIA's most current published overnight cost of a CT unit, and applies a percentage decrement to reflect the economies of scale associated with a 4-unit CT site in the Carolinas resulting in an overnight CT capital cost of $619/kW (2021$) for use in setting avoided capacity rates in this proceeding.[37] DEC/DEP Exhibit 8 provides additional supporting information for the standardized CT cost calculation methodology, which has been developed by the Companies and Dominion and accepted by the Public Staff for purposes of developing the avoided CT cost in this proceeding.

For the fixed operations and maintenance ("FOM") cost component, the Companies used the publicly available FOM data from the same EIA data source and made adjustments

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[36] *2020 Sub 167 Order*, at 6 (Finding of Fact 5).

[37] *See* U.S. ENERGY INFORMATION ADMINISTRATION, COST AND PERFORMANCE CHARACTERISTIC OF NEW GENERATING TECHNOLOGIES, ANNUAL ENERGY OUTLOOK 2021, 3 (Table 2) (February 2021), *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf (last visited Oct. 29, 2021).

using internal data to reflect the FOM economies associated with a four-unit CT project. DEC/DEP Exhibit 8 also provides additional supporting information for the FOM cost component.

3. Performance Adjustment Factor Capacity Multiplier

In past avoided cost proceedings, the Commission has recognized the PAF as a capacity multiplier designed to address standard avoided capacity rates being paid on a per-kWh basis, such that setting avoided capacity rates at a level equal to a utility's avoided capacity cost absent a PAF effectively requires QFs to operate during 100% of the on-peak hours.[38] The Commission determined that avoided capacity rates excluding a PAF left QFs without any reasonable opportunity to experience outages during each peak period to receive the total available avoided capacity payment.[39] Thus, the PAF recognizes that the Utilities' generating units experience unplanned outages and do not operate 100% of the time during peak periods and allows QFs to also experience unplanned outages during peak periods and still receive the utility's full avoided capacity costs.[40]

In the 2018 Sub 158 proceeding, the Commission approved DEC's and DEP's continued recognition of a PAF in determining the appropriate calculation of avoided capacity to be paid to QFs. The *2018 Sub 158 Order* reiterated the *2016 Sub 148 Order's* finding that inclusion of a PAF in avoided capacity rates is appropriate and should be based upon a metric or metrics that assess generating unit "availability." The Commission therefore approved the Companies' proposed PAF of 1.05, based upon the equivalent availability ("EA") metric and the use of five years of historic outage rate data during

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[38] *See 2018 Sub 158 Order*, at 40 (describing the history of the PAF).

[39] *Id.*

[40] *Id.*

DEC's and DEP's critical peak season months.[41] In accepting the Companies' utilization of the EA metric for purposes of calculating the PAF, the Commission additionally accepted the Public Staff's recommendation for the Utilities to consider other reliability metrics besides the EA. The Commission directed Duke and the Public Staff to address the appropriateness of using the Equivalent Unplanned Outage Rate ("EUOR") metric in the next avoided cost proceeding, finding that the use of the EUOR "may have merit given that EUOR [appropriately excludes planned outages from the calculation of the PAF, but] includes an additional type of outage classified as "maintenance" outages which can also occur during peak demand periods."[42]

In the streamlined 2020 Sub 167 proceeding, the Companies continued to utilize the EA metric to calculate the PAF[43] and committed to discussing the appropriateness of utilizing the EUOR metric with the Public Staff before the 2021 avoided cost proceeding. Based on that commitment, the Commission urged the parties to try to reach consensus on the appropriateness of using the EUOR metric prior to their initial filing in the present docket.[44]

Consistent with the *2018 Sub 158 Order* and the *2020 Sub 167 Order*, the Companies have worked with the Public Staff and Dominion to consider the use of other reliability metrics for developing the PAF, including the EUOR metric. Based on this review, the Companies, Public Staff and Dominion reached a consensus to adopt the Equivalent Unplanned Outage Factor ("EUOF") metric for developing the PAF. Similar

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[41] *Id.*, at 41.

[42] *Id.*; *see also 2020 Sub 167 Scheduling Order*, at 1.

[43] The Commission approved a PAF capacity multiplier of 1.06 for DEC and DEP in the *2020 Sub 167 Order*, at 6 (Finding of Fact 9), 60 (Ordering Paragraph 10).

[44] *2020 Sub 167 Order*, at 21.

to the EUOR metric, the EUOF metric includes the impact of maintenance outages which can also occur during peak demand periods and appropriately excludes planned outages from the calculation. The Companies compiled five years (2016-2020) of Generating Availability Data System ("GADS") data and calculated EUOF for the entire generation fleet, excluding Company-owned solar resources, which is consistent with the practice of using five years of GADS data in the Companies' planning models.

Use of the EUOF metric also allowed the Companies to align calculation of the PAF with the actual period that the Companies pay for capacity. For DEC, this includes the winter months of December-March and summer months of July-August. To align with DEP's actual capacity payment period, the DEP data was based only on the winter months of December-March and does not include any summer months.

Based upon these calculations and the agreed-upon methodology, DEC's and DEP's respective system weighted EUOF during this timeframe averages to approximately 4%, which results in a PAF of 1.04 for both DEC and DEP. DEC/DEP Exhibit 8 also provides additional supporting information for the PAF calculation.

4. With the expiration of the Hydro Stipulation and amendments to the North Carolina General Statutes, the Companies have discontinued the outdated 2.0 PAF for run-of-river hydro QFs.

North Carolina's legacy implementation of PURPA afforded hydro QFs with unique legislative treatment that, for a number of years, resulted in the Utilities and the Commission providing run-of-river hydro QFs without storage a 2.0 PAF.[45] The Commission approved a 2.0 PAF for run-of-river hydro QFs more than two decades ago in

[45] Prior to HB 589's enactment in 2017, the statutory definition of small power producer was limited to hydroelectric renewable resources. *See* 2017 N.C. Sess. Laws 2017-192, Part I (amending N.C. Gen. Stat. § 62-3(27a)).

the 1996 avoided cost proceedings in Docket No. E-100, Sub 79.[46] Based in part on that unique legislative treatment and the Commission's then-existing 2.0 PAF for run-of-river hydro QFs without storage, the Companies and the NC Hydro Group entered into a stipulation in Docket No. E-100, Sub 140[47] ("Hydro Stipulation"), in which the parties agreed, among other things, that the Companies would continue to include the previously-approved 2.0 PAF in standard offers filed at the Commission prior to December 31, 2020, to calculate the avoided cost rates for small hydro QFs of 5 MWs or less through December 31, 2020.[48] As the Commission recognized in the *2018 Sub 158 Order*[49] and in the prior *2016 Sub 148 Order*[50], the General Assembly has subsequently amended the State's implementation of PURPA through HB 589 in 2017 and Session Law 2019-329 to no longer designate hydroelectric generating facilities as unique small power producers, while, at the same time, establishing flexibility for the Companies to negotiate longer-term avoided cost purchase contracts and to immediately recognize the capacity contributions of certain legacy hydro QFs in calculating future avoided cost rates.[51] Because of these legislative changes pertaining to hydroelectric generating facilities, the Commission found it appropriate in Docket No. E-100, Sub 158 "to consider again the question of the

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[46] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 79, at 19 (issued June 19, 1997).

[47] *Stipulation of Settlement Among Duke Energy Carolinas, Duke Energy Progress, and NC Hydro Group*, Docket No. E-100, Sub 140 (filed Jun. 24, 2014) ("*Hydro Stipulation*").

[48] *Hydro Stipulation*, at ¶¶ 3(a), 4.

[49] *2018 Sub 158 Order*, at 42.

[50] *2016 Sub 148 Order.*, at 39.

[51] *See* N.C. Gen. Stat. §§ 62-156(b)(3), (c).

appropriate PAF to apply in calculating capacity rates to run-of-the-river hydro QFs after the natural expiration of the Hydro Stipulation."[52]

In the 2020 Sub 167 proceedings, when the expiration of the Hydro Stipulation was imminent, the Companies explained that they would retain the 2.0 PAF for run-of-river hydro QFs 1 MW and less eligible for the standard offer (in effect from November 1, 2020 until October 31, 2021). The Companies noted, however, that the Hydro Stipulation expired on December 31, 2020. Accordingly, the Companies indicated that they would include the 2.0 PAF for negotiated PPAs with hydro QFs greater than 1 MW but less than 5 MWs until December 31, 2020.[53] In the *2020 Sub 167 Order,* the Commission cited the expiration of the Hydro Stipulation and agreed with the Companies' conclusion that, after December 31, 2020, they "are no longer required to offer a 2.0 PAF to run-of-river hydro QFs greater than 1 MW but less than 5 MWs."[54] The Commission also directed the Companies to address the appropriate PAF for run-of-river standard offer hydro QFs in this initial statement.[55]

The Hydro Stipulation, by its plain terms, does not require the continuation beyond December 31, 2020 of an elevated PAF for any run-of-river hydro QFs under 5 MWs in capacity, regardless of whether the actual capacity is below, at, or above 1 MW.[56] DEC and DEP committed to "propos[ing] avoided cost rates and proposed standard terms and conditions pertaining to small hydro QFs filed at the Commission until December 31,

[52] *2018 Sub 158 Order* at 42.

[53] *Joint Initial Statement*, Docket No. E-100 Sub 167, at 17-18 (filed November 2, 2020).

[54] *2020 Sub 167 Order*, at 20.

[55] *Id.*, at 20-21.

[56] *See Hydro Stipulation*, at ¶¶ 2-4.

2020."[57] The *2020 Sub 167 Order* further recognized that the elevated PAF was no longer required for run-of-river hydro QFs with greater than 1 MW and less than 5 MWs in capacity.[58] Because the Hydro Stipulation does not distinguish between run-of-river hydro QFs with capacity below 1 MW and those with capacity at 1 MW and up to 5 MWs, but rather treats and defines them all as "small hydro QFs,"[59] it is now appropriate to also discontinue the elevated PAF for run-of-river hydro QFs with capacity at or under 1 MW. Thus, in this first avoided cost proceeding following the expiration of the Hydro Stipulation, DEC and DEP have developed and are proposing standard offer avoided cost rates for run-of-river hydro QFs that reflect the same standard PAF of 1.04, not the elevated and outdated PAF of 2.0. Because the elevated PAF is no longer required by the expired Hydro Stipulation or other Commission Order, any continuation of the elevated 2.0 PAF for run-of-river hydro QFs would lead to inappropriate and excessive costs for customers.

c. Avoided Energy Cost Calculations

Avoided energy costs represent an estimate of the variable costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. Avoided energy costs, which are expressed in dollars per megawatt-hour ("$/MWh"), include items such as avoided fuel and avoided variable operating and maintenance ("VOM") expenses. The peaker method credits the QF for avoiding energy, more specifically fuel and VOM costs, from the most expensive unit projected to be operating on the system at a given point in time, which is often referred to as the marginal unit. Consistent with the approach followed in the 2020 Sub 167 and prior proceedings, the

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[57] *Id.*, at ¶ 4.

[58] *2020 Sub 167 Order*, at 20.

[59] *Hydro Stipulation*, at ¶ 3.

Companies have relied upon the PROSYM production cost modeling platform to derive the Companies' system marginal energy costs, which represents the forecasted energy costs that a QF could avoid. The Companies have updated their avoided energy cost calculations consistent with the *2020 Sub 167 Order*, as further described below.

1. Natural Gas Commodity Price Forecast Methodology

The appropriate methodology to accurately forecast commodity prices over the fixed future term of standard offer avoided cost contracts has been a contested issue in biennial avoided cost proceedings since 2014 when the Companies began relying upon ten years of forward contract natural gas market price data.

For IRP purposes, the Companies' 2014, 2016, 2018, and 2020 biennial IRPs have utilized ten years of forward natural gas market price data before transitioning to commodity price estimates derived based upon fundamental forecasts over the remainder of the planning period.

For avoided cost purposes, however, the Commission determined in the *2016 Sub 148 Order, 2018 Sub 158 Order*, and *2020 Sub 167 Order* that the Companies should be required to calculate their respective avoided energy costs using forward contract natural gas prices for no more than eight years before transitioning to fundamental forecast data for the remainder of the planning period.[60] In a good faith effort to reduce the number of potential contested issues for the Commission's determination, the Companies have elected to extend that approach to the instant proceeding. Specifically, the Companies are relying upon forward market price data for eight years (2022-2029) as an indicator of the near-term future commodity costs of natural gas for purposes of calculating the Companies'

[60] *2016 Sub 148 Order*, at 109 (Ordering Paragraphs 5-6); *2018 Sub 158 Order*, at 136 (Ordering Paragraph 20), *2020 Sub 167 Order*, at 60 (Ordering Paragraph 12).

avoided energy cost rates before transitioning to fundamental forecast data starting in year nine (2030-2031). As in prior avoided cost proceedings, these market prices were obtained from an actual forward purchase to determine the market price of gas and forward market liquidity. This approach is consistent with both the *2018 Sub 158 Order* and *2020 Sub 167 Order*, and the Companies and the Public Staff have achieved consensus on the Companies' methodological approach.

2. Avoided Fuel Hedging Cost Adjustment

Whether to pay QFs an avoided fuel hedging value for their must-purchase power under PURPA has also been a contested issue in prior avoided cost proceedings. In the *2018 Sub 158 Order*, the Commission determined that renewable generation is capable of providing fuel price hedging benefits and, accordingly, required DEC and DEP to recalculate their avoided energy rates to include a fuel hedging adjustment utilizing the Black-Scholes Model to determine the hedging value of renewable generation.[61] After conferring with the Public Staff, the Companies updated their avoided energy rate calculations to incorporate the same hedge value that the Commission approved for Dominion in the *2018 Sub 158 Order*.[62]

For purposes of the streamlined 2020 Sub 167 proceeding, the Companies developed their respective avoided energy rates to again incorporate the same avoided fuel hedge value accepted for Dominion in the 2018 Sub 158 proceeding, while continuing to

[61] *2018 Sub 158 Order*, at 62.

[62] *See Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Compliance Filing*, Docket No. E-100, Sub 158 (Filed Nov. 1, 2019). The Companies reaffirmed their November 1, 2019 compliance filings after the Commission issued its *2018 Sub 158 Order* in April 2020.

question the appropriateness of this adjustment.[63] The *2020 Sub 167 Order* directed all interested parties to address the issue in the next avoided cost proceeding.[64]

After discussing this issue with the Public Staff, and in an effort to reduce the number of potential contested issues for the Commission's determination, the Companies have used the Black-Scholes option pricing method to calculate a fuel hedging adjustment that aligns with the methodology used by Dominion and accepted by the Public Staff and the Commission in recent proceedings. The Companies' Black-Scholes calculation resulted in a fuel hedge value of $0.02/MWh and is incorporated in the Companies' avoided energy rates in this docket. <u>DEC/DEP Exhibit 8</u> provides additional supporting information for the avoided fuel hedging adjustment.

3. <u>Avoided Line Loss Adjustment for Standard Offer QFs under 1 MW and Criteria for Distribution-Connected QFs Greater than 1 MW</u>

The Companies' Schedule PP rates, as approved in the 2020 Sub 167 proceeding and prior proceedings, include avoided energy credits that vary depending on whether the QF is interconnected with and delivering energy into the transmission or distribution system. In the past, the Companies have consistently supported offering different avoided energy credits based on the point of interconnection to the Companies' systems, because this approach more accurately reflected differences in DEC's or DEP's actual avoided costs due to differences in avoided energy line losses for transmission level and distribution level QFs.

[63] *2018 Sub 158 Order*, at 102.

[64] *Id.*, at 30, 60 (Ordering Paragraph 13).

In the 2018 Sub 158 proceeding, the Companies undertook a line loss study evaluating power backflow on substations caused by QFs on the DEC and DEP systems.[65] The studies showed that the number of substations on their respective systems where backflow was reducing or negating the avoided line loss benefits of distribution-connected QFs was not substantial enough to eliminate the line loss adder for relatively small 1 MW or less standard offer QFs. Accordingly, both DEC and DEP determined that it was appropriate to continue offering a line loss adder. The Commission approved the Companies' inclusion of a line loss adjustment in Schedule PP and further directed the Utilities to continue to "study the impact of distributed generation on power flows on their distribution circuits and to provide the results of those studies as a part of their initial filings in the 2020 Sub 167 avoided cost proceeding."[66]

In the 2020 Sub 167 proceeding, the Companies again analyzed the levels of connected, under construction, and queued QF solar generating facilities interconnected to the DEC and DEP distribution systems to determine the number of substations that were then currently experiencing or expected to experience significant backfeed in the near future because of the recent growth in utility-scale QF capacity. Based upon this analysis, the Companies determined that retaining a line loss adder for distribution-connected

[65] In the 2016 Sub 148 proceeding, Dominion initially filed a study showing that surging distribution-interconnected QF solar development was causing power backflow on substations throughout Dominion's North Carolina service territory. Relying upon the Dominion study, the Commission determined that the previously-recognized "avoided line loss benefits associated with distributed generation have been reduced or negated" for future QFs requesting to interconnect to the Dominion distribution system, and approved Dominion's request to eliminate the line loss adder from its standard offer avoided energy payments for QFs interconnecting on its distribution network. *2016 Sub 148 Order*, at 8 (Finding of Facts 17-18).

[66] *2018 Sub 158 Order*, at 36. The Commission also found that the Companies' proposal to assess the individual characteristics of QFs that are not eligible for Schedule PP standard offer rates and to address the line loss adder analysis as part of the PPA negotiation process was consistent with N.C. Gen. § 62-156(c) by taking into consideration the individual characteristics of the QF. *Id.*

standard offer-eligible QFs contracting under Schedule PP was appropriate. For proposed distribution-connected QFs not eligible for Schedule PP, the Companies committed to continue considering whether the QF's energy output would continue to backfeed at the substation and inject energy onto the transmission system.

The *2020 Sub 167 Order* approved the Companies' proposed distribution line loss adder for standard offer-eligible QFs contracting under Schedule PP.[67] The Commission, at the Public Staff's recommendation, also directed the Companies to evaluate and report on (1) any geographical concentrations of back-feeding substations, and (2) whether a rate design with or without a line loss adder based on the amount of back-feeding at a substation would be appropriate to provide a more accurate avoided costs rate to QFs regarding the value of energy at the selected station.[68] The Commission further directed the Companies to discuss these issues with the Public Staff and Stakeholders prior to filing in the 2021 avoided cost rate proceeding.[69]

As reported in the Companies' seventh 45-day report, the Companies evaluated the geographic concentration of backfeeding substations and found that both DEC and DEP are currently experiencing increasing levels of backflow into the transmission system due to increasing QF solar generation.[70] The Companies' updated analysis showed, in DEP, 106 out of 407 substation banks, or 26%, are backfeeding into the transmission system due to distribution-connected generation. For DEC, the percentages of substation banks experiencing backfeed due to distribution-connected projects continues to be significantly

[67] *2020 Sub 167 Order*, at 35, 59-60 (Ordering Paragraphs 5-6).

[68] *Id.*, at 35

[69] *Id.*

[70] *Seventh Joint 45-Day Progress Report of Duke Energy Carolinas, LLC And Duke Energy Progress, LLC*, Docket No. E-100, Sub 167 (filed Sept. 7, 2021).

less—only 48 out of 1048 banks analyzed, or 4.6%, are backfeeding.

DEC/DEP Exhibit 9 presents a map showing the geographic locations of substations with backflow in North and South Carolina. This exhibit shows the concentrated nature of QF solar development in more rural areas, especially in the DEP eastern North Carolina service territory. However, distribution-connected QFs continue to not be as geographically concentrated in DEC or DEP territory as compared to Dominion.[71] While a certain level of backflow into the transmission system is not likely to offset the line loss benefits of distributed generation, the Companies' analysis suggests that there is a point at which additional generation will start to increase substation losses. Specifically, the near-term contribution or impact of adding one or more 1 MW standard offer QFs on substation backflow is not likely to be substantial enough to offset the line loss benefit, while more significant concentrations of larger distribution-connected QFs may increase backflow to the point where the line loss adder is no longer appropriate.

Based upon the Companies' most recent analysis, both DEC and DEP propose to maintain the line loss adder for standard offer-eligible QFs contracting under Schedule PP at this time. For QFs greater than 1 MW that are not eligible for the standard offer, which could backflow a more significant amount of energy into the transmission system, the Companies propose to assess the individual characteristics of the QF and address through negotiation of the PPA whether retaining or eliminating the line loss adjustment from the avoided energy value is appropriate on a case-by-case basis. Specifically, the Companies will assess the amount of potential backflow from distribution-connected QFs greater than

[71] For comparison, Dominion's study presented in the Sub 158 proceeding identified that out of 38 transformers with solar distributed generation, 16 were realizing consistent backflow, and only two had positive flow or additional capacity for load reduction capability. *Dominion Energy North Carolina Initial Statements and Exhibits*, Docket No. E-100, Sub 158 at 35 (filed Nov. 1, 2018).

1 MW against the following criteria to determine if the line loss adder is appropriate: (i) the substation bank that serves the distribution point-of-interconnection has DER backflow of greater than or equal to 50% ,[72] or (ii) the addition of the QF would cause the DER backflow to become greater than or equal to 50%. If these criteria are met, the QF will receive the transmission rates that exclude marginal loss factors for capacity and energy.

4. <u>Updated Solar Integration Cost Decrement Supported by the 2021 Astrapé SISC Study</u>

The avoided costs (and the potential for increased ancillary service costs) associated with integrating incremental solar generation has been an issue of significant importance in recent avoided cost proceedings as North Carolina has experienced unparalleled growth in utility-scale QF solar interconnected with and injecting power into the Companies' systems. In response to the *2016 Sub 148 Order,*[73] the Companies first proposed an integration services charge in the 2018 Sub 158 proceeding specific to integrating new intermittent solar energy generation into the Companies' systems. These charges were calculated based upon a solar integration cost study by Astrapé Consulting ("2018 Astrapé SISC Study") and were designed to quantify the impact on operating reserves, or increased generation ancillary service requirements, necessary to integrate new variable and non-dispatchable solar capacity into the DEC and DEP systems.[74] The 2018 Astrapé SISC

[72] The DER backflow % is calculated by dividing the summation of backflow energy measured at the substation bank by the DER generation on that substation bank. 50% backflow is the point in which the amount of DER generation being consumed locally equals the amount of DER generation backflowing into the transmission system.

[73] *2016 Sub 148 Order*, at 98 (explaining that it would be "appropriate for the Utilities to propose schedules specific to QFs that provide intermittent, non-dispatchable power, if the Utilities' cost data 'demonstrates marked differences' in the value of the energy and capacity provided by these QFs").

[74] The initial 2018 Astrapé SISC Study supporting the 2018 integration services charges was filed with the Commission as DEC/DEP Exhibit 2 to the Companies' Reply Comments on March 27, 2019, in Docket No. E-100, Sub 158.

Study showed that, as solar penetration increases, the cost to integrate these variable and intermittent resources while maintaining operational reliability also increases.

The 2018 Astrapé Study quantified both the average integration cost for a given block of solar capacity as well as the higher, incremental integration cost associated with integrating additional increments of solar above the levels already interconnected to the DEC and DEP systems. Balancing the interests of customers and solar QFs, the Companies requested approval of integration services charges that would apply only to new QFs requesting to sell power under Sub 158 avoided cost rates and that were designed to reflect the "average" (lower) integration cost for all solar resources operating on the system versus assigning the full "incremental" integration costs to new solar resources.[75]

After receiving extensive evidence on the issue, the Commission approved the Companies' proposed solar integration services charge values supported by the 2018 Astrapé Study of $1.10/MWh for DEC and $2.39/MWh for DEP, to be included as a component of each utility's avoided energy costs.[76] The Commission further determined that to remain consistent with FERC's regulations implementing PURPA that these average integration charges should remain fixed during the term of the new QF's contract, as opposed to being subject to biennial adjustments throughout the term of the contract.[77]

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[75] Incremental integration costs identified in the 2018 Astrapé SISC Study for solar above the HB 589 mandated procurement requirements would have imposed significantly higher incremental integration cost, but would not have needed to be updated as each vintage of solar QF would have been assigned their full incremental integration cost at the time of contracting. The Companies did not recommend this approach in the interest of balancing the impact on new QFs versus existing QFs.

[76] *2018 Sub 158 Order*, at 90-95. The Commission also approved an exemption for Controlled Solar Generators from being assigned the solar integration cost decrement.

[77] *Id.*, at 95. Notably, the recent changes to FERC's PURPA regulations in Order No. 872 further supports the Companies' position that it would be appropriate to update avoided energy rates and, by extension, the solar integration services charge, in each biennial proceeding. 18 C.F.R. 292.304(d)(2); Order No. 872, at P 256 ("giving states the flexibility to require variable avoided cost energy rates in QF contracts and other LEOs in order to better comply with Congress' clear instruction in PURPA that the [FERC] may not require

The Companies continued to include these initial solar integration services charge decrement values in the avoided energy rates filed and approved in the 2020 Sub 167 proceeding.[78]

The *2018 Sub 158 Order* also directed the Companies to undertake an independent technical review of the Astrapé Study to inform future biennial avoided cost proceedings about the Companies' ancillary services costs associated with integrating intermittent, non-dispatchable generation.[79] As detailed in each of the eight 45-Day progress reports filed with the Commission in the Sub 167 docket, the Companies initiated the independent technical review of the Astrapé Study's methodology and modeling used for system simulations. Brattle Consulting led the review as principal consultant with the involvement of technical experts from three national renewable energy laboratories as well as participation by the Public Staff and the South Carolina Office of Regulatory Staff as regulatory observers. The TRC Report is included as DEC/DEP Exhibit 10 to the Companies' Joint Initial Statement. The Public Staff has indicated that it supports the analysis set forth in the TRC's report.

Taking into account input from the TRC and at the Companies' direction, Astrapé Consulting developed an updated 2021 Solar Integration Services Charge Study that incorporates the TRC report's findings and updates its modeling and analysis of the integration costs associated with integrating incremental solar into the DEC and DEP systems. The 2021 Astrapé SISC Study is included as DEC/DEP Exhibit 11 to the

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QF rates in excess of a purchasing utility's avoided cost."). However, the Companies are not proposing to modify the fixed structure of the charge approved in the *2018 Sub 158 Order* in this proceeding.

[78] *2020 Sub 167 Order*, at 36.

[79] *2018 Sub 158 Order*, at 95.

Companies' Joint Initial Statement.

Based upon Astrapé's updated analysis, the Companies have incorporated solar integration cost decrements of $1.05 per MWh for DEC and $2.26 per MWh for DEP into the uncontrolled solar avoided energy rates.

5. Review of Potential for QFs to Provide Positive Ancillary Services

As one of the Sub 158 Additional Issues, the Commission directed the utilities to address the potential for QFs to provide positive ancillary services and, if warranted, the proper compensation for doing so. The Commission instructed that utilities should evaluate:

> [W]hether a QF that can sufficiently demonstrate its ability, and contractually obligates itself, to operate in a manner that provides positive ancillary service benefits at a lower cost than the utility's own conventional resources, should be appropriately compensated for those benefits, and an identification of mechanisms to quantify the ancillary service benefits that such innovative QFs can provide[.][80]

To comply with the Commission's directive, the Companies investigated this complex issue, by assessing needed changes to system operations to incorporate third-party QF ancillary services into the DEC and DEP systems in a way that would maintain system reliability, analyzing approaches taken in other states, and engaging with the Public Staff and interested stakeholders. Based upon this analysis, the Companies concluded that a QF selling "must take" energy under PURPA cannot provide incremental positive ancillary services value under current system operations. In addition, the Companies found that QFs are already fully compensated for their capacity and energy output under the peaker method such that no additional compensation is appropriate under PURPA.

[80] *2018 Sub 158 Order*, at 136 (Ordering Paragraph 24).

FERC defines ancillary services as services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."[81] In other words, ancillary services are functions that allow a utility to maintain the reliability of the system and provide flexibility needed to respond to disruptive events by re-balancing the system. Some of the more prominent types of ancillary services include: (1) regulating reserves, which are used to manage the active power volatility of a balancing authority's ("BA") load and generation resources; (2) contingency reserves, which are resources that can respond in fifteen minutes to a disturbance event; (3) balancing reserves, which are unused MWs that can be called upon to re-balance the system as needed; and (4) black start, which are resources that have the ability to bring resources back online following an outage. The avoided peaker for which the QF is being compensated is capable of providing all of these services other than black start services.

A fundamental aspect of each of these ancillary services is that system operators must have control over the assets to dispatch them quickly as need arises. For example, regulating reserves require both dispatch by Automatic Generation Control ("AGC") as well as integration into the BA model to allocate the dispatch instructions across all units on AGC simultaneously. At this time, DEC and DEP system operators do not have such control over third-party QF resources. For this reason, QFs do not have the ability to "operate in a manner that provides positive ancillary service benefits" or "at a lower cost

[81] *See* FERC Order No. 890, App'x A (Pro Forma Open Access Transmission Tariff), at I.1.2; *see also* Joint Open Access Transmission Tariff of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Duke Energy Florida, LLC, at I.1.2, accessible at http://www.oatioasis.com/duk/index.html.

than the utilities' own conventional resources." Moreover, transitioning the BA's modeling and dispatch optimization to rely upon many small QF resources rather than a few large facilities would require a fundamental change in how the grid is operated, along with major technical and financial investments. The significant cost necessary to fund modeling, engineering support, communications, and other projects needed to enable a system dependent on myriad third parties for ancillary services would increase costs versus avoid costs for the Companies.

The QF "must take" PURPA framework that DEC and DEP operate under today is also simply not compatible with QFs providing positive ancillary services that would contribute to DEC and DEP reliably meeting their system planning and operating reserve requirements. First, the payment structure for "must take" PURPA QFs is the achieved energy and capacity export calculated based upon delivered energy. Providing ancillary services to the Companies would inherently require the QF to produce less than its maximum energy and capacity (whether by following a signal to ramp down or by holding back some or all of its export to maintain an ability to ramp up when dispatched). Further, as addressed extensively in the 2018 Sub 158 proceeding, the Companies' experience has been that integrating solar QFs *increases* the need for ancillaries on the DEC and DEP systems, as the solar QF's output is variable and intermittent and dependent, to some extent, on unpredictable environmental factors. In contrast to providing additional value to support balancing the system, these QFs must first eliminate their own demand for increased ancillaries such as regulating reserves by operating in a controlled manner to smooth their output before conceivably providing additional value to balancing the system. To date, no solar QFs have demonstrated that their facility is capable of operating—and contractually agreed to operate—as a "Controlled Solar Generator" in a manner that materially reduces or eliminates the need for additional ancillary service requirements.

Importantly, while FERC has recognized that energy sold under PURPA "includes capacity, energy and ancillary services[,]"[82] FERC has not suggested that any incremental value above the utility's avoided costs calculated under the peaker method is appropriate. Put another way, the value of positive ancillary services provided by a QF as part of the capacity and energy delivered to the utility, if any, is already incorporated into the calculation of the utility's full avoided cost rates. Importantly, the Companies have not identified any utility that uses small power producer QFs to provide ancillary services under PURPA nor any state Commission implementing PURPA that has asserted any incremental compensation is owed to QFs for providing positive ancillary services over and above the full avoided capacity and avoided energy value paid to QFs. Further, there is not an incremental need for ancillary services on the Companies' systems as the Companies' existing generating fleets are capable of providing all needed ancillary services.[83]

Consistent with the Companies' findings developed through the foregoing investigation, the Companies are not proposing any changes to their avoided cost rates or terms in this proceeding relating to provision of positive incremental ancillary services by QFs in North Carolina.

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[82] *See Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, 123 FERC ¶ 61,055, n. 869, 2008 FERC LEXIS 788, (Apr. 21, 2008).

[83] The quantity of ancillary services needed across the Companies is relatively limited, with a baseline planning number of around 230 MWs of regulating reserve and around 950 MWs of daily contingency reserve (for which DEC and DEP already have approximately 1.3 GW of off-line contingency reserve). In addition, the frequency response obligations for DEC and DEP are quite small at -35.2 MW/0.1Hz and -21.7 MW/0.1Hz, respectively.

IV. **“As-Available” Rates in Schedule PP**

As another of the Sub 158 Additional Issues, the Companies have evaluated developing more real-time pricing tariff options for QFs selling under Schedule PP, specifically focusing on the new rate options prescribed under FERC Order No. 872. Under FERC’s regulations implementing PURPA’s mandatory purchase obligation, a QF may elect to sell energy either (1) as the QF determines energy to be available based on avoided cost rates “calculated at the time of delivery”; or (2) pursuant to a legally enforceable obligation for delivery of energy or capacity over a specified term for rates calculated either at the time of delivery or at the time the obligation is incurred.[84] In Order No. 872, FERC amended its regulations to provide states greater flexibility to (i) utilize locational marginal prices (where available) or competitive prices to set rates for as-available QF energy sales[85] and (ii) mandate that variable avoided energy rates calculated at time of delivery could also be used to set the energy rates for QFs electing to sell energy pursuant to a LEO.[86] With respect to the latter, FERC provided state regulatory authorities “flexibility to require that energy rates (but not capacity rates) in QF power sales contracts and other LEOs vary in accordance with changes in the purchasing electric utility’s as-available avoided costs at the time the energy is delivered.”[87] Explaining this new rule, FERC recognized that allowing states to implement variable energy rates in QF contracts

[84] 18 C.F.R. 292.304(d)(1)-(2).

[85] 18 C.F.R. 292.304(b)(6)-(7).

[86] 18 C.F.R. 292.304(d)(1)(iii) (“The rate for delivery of energy calculated at the time the obligation is incurred may be based on estimates of the present value of the stream of revenue flows of future locational marginal prices, or Competitive Prices during the anticipated period of delivery.”); 18 C.F.R. 292.304(d)(2) (“[A] state regulatory authority . . . may require that rates for purchases of energy from a qualifying facility pursuant to a [LEO] vary through the life of the obligation, and be set at the electric utility's avoided cost for energy calculated at the time of delivery.”).

[87] 18 C.F.R. 292.304(d)(2).

based on the time of delivery "ensures that QF rates do not exceed the avoided cost rate cap imposed by PURPA[,]" thus balancing the risk allocation between QFs and utility customers.[88]

Likewise, FERC underscored that the use of transparent market prices to establish as-available rates "allows those rates to automatically adjust—up and down—as avoided costs change."[89] Accordingly, FERC revised its regulations to permit state regulatory authorities to set "as-available" rates using either pricing established through a liquid market hub or "Combined Cycle Prices" established by a state-approved formula incorporating "published natural gas price indices, a proxy heat rate, and variable operations and management costs[.]"[90] FERC also identified that its regulations and intent in allowing these competitive pricing mechanisms is to allow States greater flexibility to accurately measure a purchasing electric utility's avoided cost for as-available energy at the time of delivery.[91]

Consistent with FERC's policy goals and analysis in Order No. 872, the Companies are proposing to update the Schedule PP tariff to use the hourly marginal cost of producing energy ("Marginal Cost Rates") to calculate avoided costs for QFs that elect to sell energy to the Companies on an "as-available" basis. The Companies' Marginal Cost Rates will be calculated ex-post at the end of the month for each hour in a given month based on the

[88] FERC Order 872, at ¶ 723.

[89] *Id.*, at ¶ 31.

[90] 18 C.F.R. 292.304(b)(7)(i)-(ii).

[91] FERC Order 872, at ¶ 214.

joint dispatch outcomes for DEC and DEP[92] during that month using the incremental cost of production of the next megawatt hour.

Because the Marginal Cost Rates are calculated at the end of each calendar month, QF compensation will be based on actual marginal costs rather than market forecasts. In this way, "as-available" rates will accurately compensate QFs for the energy they provide based upon the utility's avoided costs calculated "at the time of delivery" in accordance with PURPA, while protecting the Companies' customers from potential overpayment. Notably, the Companies currently use this methodology to calculate transmission and wholesale imbalance billing rates.[93]

The Companies also investigated developing a projection of avoided energy costs on a day-ahead basis but determined that QFs putting power to the utility and its customers under the "as-available" rate already have the option to sell to the Companies or other markets, such as PJM, Southern Company, or Dominion, in the forward day-ahead market based on the projected wholesale need and value of purchased power at that point in time. Through their participation in the wholesale markets, these customers would receive information about day-ahead pricing. If the QF does not sell its output to Duke or other market participants, it can put its power to DEC or DEP under the "as-available" rate and receive the value the avoided energy created for the Companies' customers at the time of delivery using the ex-post pricing described in the rate. Importantly, QFs that commit to

[92] The Companies will determine joint dispatch of DEC and DEP system resources based upon, among other things, (1) the incremental variable production cost, including fuel, variable operating and maintenance expenses, emission allowances, and reagents; (2) the replacement cost of supply resources, including power plants; and (3) start-up costs for peaking units.

[93] Duke Energy Florida's methodology for calculating as-available avoided energy costs similarly relies upon an ex post calculation based on real costs the utility actually avoided during each hour that as-available energy was delivered. *See* Duke Energy Florida, Tariff Section No. IX, Fourth Revised Sheet No. 9.320 Appendix A, Schedule 2.

sell their full output to the Companies, under a legally enforceable obligation, have other PURPA-guaranteed rate options for fixed price power sales of various terms, but for those QFs that elect to sell and deliver power "as-available" and maintain the option to sell off-system to another entity, the ex post methodology most accurately reflects the utility's actual avoided cost at the time of delivery and will best protect customers from over- or under-estimations of the actual costs avoided when the energy is delivered.

The Companies are also retaining the 2-year Variable Rates contract option that exists under the Schedule PP approved in the *2020 Sub 167 Order*; however, this rate option will now require a QF to contractually obligate itself to sell and deliver power for at least a two-year term to reflect that the Companies are forecasting avoided costs over this period.

At this time, and after discussion with Public Staff and other stakeholders, the Companies are not proposing to offer a long-term fixed capacity rate and variable energy rate option based upon the Companies' avoided energy cost calculated at the time of delivery, as now allowed under 18 C.F.R. 292.304(d)(2). In future biennial proceedings, the Companies will continue to evaluate this concept along with the other new options for establishing avoided cost rates under FERC's implementing regulations, as updated in Order No. 872.

V. <u>Schedule PP Rate Design</u>

The Companies' Schedule PP pays QFs on a volumetric rate basis (*i.e.*, both avoided energy and capacity is paid on a $/kWh basis versus a separate fixed payment for capacity).[94] The rates are designed to credit QFs for avoided energy supplied during pre-designated on-peak and off-peak hours. Energy credits are applicable to all QF energy supplied during the year and vary for the designated on-peak, premium-peak and off-peak hours in a day. Capacity credits are applicable to all QF energy supplied during the designated capacity payment hours.

In the 2018 Sub 158 proceeding, DEC and DEP initially proposed an updated Schedule PP rate design that eliminated the pre-existing Option A and Option B rate structures and proposed more granular rate designs to better recognize the value of QF energy and capacity. After engaging with the Public Staff on rate design issues, the Companies filed a Partial Settlement with the Public Staff on April 18, 2019, addressing the Companies' and the Public Staff's agreement on appropriate avoided energy and avoided capacity rate design methodologies ("Sub 158 Rate Design Stipulation").[95] Overall, the Sub 158 Rate Design Stipulation's avoided cost rate designs sought to better balance the need for a granular rate design with providing Schedule PP customers clear and consistent price signals through the term of customers' contracts. The *2018 Sub 158 Order* approved the Sub 158 Rate Design Stipulation and found the rate designs included therein to be appropriate for use in calculating DEC's and DEP's avoided energy and capacity rates.[96] The Companies utilized the same rate design in the streamlined Sub 167 proceeding, and the Commission approved the same, but instructed that Duke and the Public Staff should "continue to discuss the treatment of start costs in production cost

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[94] Due to the smaller size of QF Sellers under the standard offer, the Schedule PP rates are technically paid on ¢/kWh basis.

[95] *Agreement and Stipulation of Partial Settlement*, Docket No. E-100 Sub 158 (filed Apr. 18, 2019).

[96] *2018 Sub 158 Order*, at 8 (Finding of Fact 4).

modeling for further consideration in the November 2021 filing, as well as other general rate design issues."[97]

In this proceeding, the Companies are continuing to utilize the Commission-approved avoided energy rate designs outlined in the Sub 158 Rate Design Stipulation. Figure 2 details the avoided energy rate design for DEC and DEP. As exemplified in Figure 2, Summer months are defined as calendar months June through September and Winter months are defined as calendar months December through February. All other months are defined as Shoulder months.[98]

<u>Figure 2</u>

<table>
<tr><th colspan="25">DEC Energy Independent Price Blocks</th></tr>
<tr><td></td><td colspan="3">Summer Premium Peak</td><td colspan="3">Summer On-Peak</td><td colspan="2">Summer Off-Peak</td><td colspan="3">Winter Premium Peak</td><td colspan="3">Winter On-Peak (AM)</td><td colspan="3">Winter On-Peak (PM)</td><td colspan="2">Winter Off-Peak</td><td colspan="3">Shoulder On-Peak</td><td colspan="2">Shoulder Off-Peak</td></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer (Jun - Sep)</td><td colspan="12">Off</td><td colspan="4">On</td><td colspan="4">Premium</td><td colspan="2">On</td><td colspan="2">Off</td></tr>
<tr><td>Winter (Dec - Feb)</td><td colspan="5">Off</td><td>On</td><td colspan="3">Premium</td><td>On</td><td colspan="7">Off</td><td colspan="5">On (PM)</td><td colspan="2">Off</td></tr>
<tr><td>Shoulder (Remaining)</td><td colspan="6">Off</td><td colspan="4">On</td><td colspan="6">Off</td><td colspan="7">On</td><td>Off</td></tr>
</table>

<table>
<tr><th colspan="25">DEP Energy Independent Price Blocks</th></tr>
<tr><td></td><td colspan="3">Summer Premium Peak</td><td colspan="3">Summer On-Peak</td><td colspan="2">Summer Off-Peak</td><td colspan="3">Winter Premium Peak</td><td colspan="3">Winter On-Peak (AM)</td><td colspan="3">Winter On-Peak (PM)</td><td colspan="2">Winter Off-Peak</td><td colspan="3">Shoulder On-Peak</td><td colspan="2">Shoulder Off-Peak</td></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
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<tr><td>Winter (Dec - Feb)</td><td colspan="4">Off</td><td colspan="2">On</td><td colspan="3">Premium</td><td colspan="2">On</td><td colspan="7">Off</td><td colspan="4">On (PM)</td><td colspan="2">Off</td></tr>
<tr><td>Shoulder (Remaining)</td><td colspan="5">Off</td><td colspan="5">On</td><td colspan="7">Off</td><td colspan="6">On</td><td>Off</td></tr>
</table>

This methodology is consistent with the modeling approach utilized in the approved 2018 Sub 158 and 2020 Sub 167 avoided energy rates, and the Public Staff has indicated that it supports the Companies' approach to this calculation.

Under the Sub 158 Rate Design Stipulation, QF capacity rates are paid on a per-kWh basis across a pre-determined set of seasonal hours that represent the hours most likely to have capacity value. Paying QFs for capacity on a per-kWh basis is consistent

[97] *2020 Sub 167 Order*, at 40. The Companies' treatment of start costs is further addressed in <u>DEC/DEP Exhibit 8</u>.

[98] The specific on-peak, off-peak and premium peak hours are detailed in the MONTHLY RATE section of DEC's and DEP's respective Schedule PPs.

with the approach the Companies have historically utilized with respect to QF rate design under prior vintages of Schedule PP. The Public Staff and the Companies agreed in the Commission-approved Sub 158 Rate Design Stipulation to utilize the Companies' seasonal and hourly allocations of capacity payments based upon the loss of load risk identified in the Astrapé 2018 Solar Capacity Value Study. Astrapé completed a new resource adequacy study in 2020, and the Companies have used the loss of load risk identified in this more recent study for updating the avoided capacity rate design in this proceeding.

For the 2020 Resource Adequacy Study, the Companies utilized a stakeholder engagement process which included participation from the Public Staff, South Carolina Office of Regulatory Staff, and the North Carolina Attorney General's Office. All inputs were updated in the new study, and solar projections increased compared to the previous study. Astrapé also incorporated an enhancement for modeling load during extreme cold weather which shifted some of the winter loss of load risk from PM hours to AM hours.

The Sub 175 Schedule PP capacity rate design reflects updated pricing periods to most accurately reflect the marginal capacity value to customers during each period, as exemplified below in Figure 3. For DEC, the updated pricing periods include capacity payments during the PM hours in the summer months of July and August and AM hours in the winter months of December, January, February and March. For DEP, the updated pricing periods include AM hours during the winter months of December, January, February and March and do not include a summer pricing period. No capacity payments apply during the remaining months for either DEC or DEP. The highest prices are paid in the early morning winter hours to recognize the greater loss of load risk and greater value of capacity during those hours.

Figure 3 highlights the Summer and Winter on-peak hours for DEC and DEP.

<u>Figure 3</u>

<table>
<tr><th colspan="25">DEC Capacity Independent Price Blocks</th></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
<tr><td>Summer (Jul - Aug)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td colspan="4">Summer</td><td></td><td></td><td></td></tr>
<tr><td>Winter (Dec - Mar)</td><td></td><td></td><td></td><td></td><td></td><td colspan="5">Winter</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

<table>
<tr><th colspan="25">DEP Capacity Independent Price Blocks</th></tr>
<tr><td>Hour Ending</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td><td>6</td><td>7</td><td>8</td><td>9</td><td>10</td><td>11</td><td>12</td><td>13</td><td>14</td><td>15</td><td>16</td><td>17</td><td>18</td><td>19</td><td>20</td><td>21</td><td>22</td><td>23</td><td>24</td></tr>
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</table>

The seasonal allocation of capacity value remains heavily weighted to winter based on the impact of summer versus winter loss of load risk. The seasonal allocation is driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. DEP's loss of load risk is 100% winter, which is unchanged from that approved in the *2018 Sub 158 Order* and *2020 Sub 167 Order*. DEC's loss of load risk increased from 90% winter in the Sub 158 and Sub 167 proceedings to 96% winter in this proceeding based on the 2020 Resource Adequacy Study.

In summary, the Companies have designed their avoided capacity and energy rates in accordance with the stipulated rate design approved in the *2018 Sub 158 Order* and incorporated updated loss of load risk data from the 2020 Resource Adequacy Study to inform the avoided capacity rate design.[99] The Companies have engaged with the Public Staff prior to this filing and plan to continue to discuss the accuracy and appropriateness of the rate design with the Public Staff between now and the next biennial avoided cost proceeding.

[99] The Companies have provided further detail regarding their avoided energy and avoided capacity rate design in <u>DEC/DEP Exhibit 8</u>.

VI. Modifications to Schedule PPs and Terms and Conditions

The Companies have amended their Schedule PP tariffs to reflect the updated avoided cost rates supported in Sections III above and the revised as-available rate structure discussed in Section IV. The Companies have also made limited modifications to their Schedule PP and Terms and Conditions approved in the *2020 Sub 167 Order*. For Schedule PP, these changes include:

- Administrative revisions for clarity and consistency, such as revising references to refer to "Seller" rather than "Customer" and to refer to types of rates as "Rates" rather than "Credit Rates";
- Ensuring that references to rates accurately and clearly distinguish between Long-Term Rates, Variable Rates (the two-year rates that are subject to adjustment at every biennial avoided cost proceeding before the Commission), and the new Marginal Cost Rates that are the Companies' "as-available rates";[100]
- In the Capacity Credit schedule, updating and simplifying the schedule to reflect that hydroelectric generation QFs receive the same capacity credits as other QFs, although there are two applicable categories for hydro QFs depending upon whether they are a legacy hydro QF that is statutorily eligible for capacity payments that begin in the first year of the standard contract, similar to swine-waste and poultry-waste QFs, or hydro QFs that do not qualify for the statutory exemption and that

[100] In the 2002 avoided cost proceeding, the Commission directed that the two-year variable rate acted as the "as available" rate for purposes of the standard offer. Because the Companies have proposed an updated methodology for determining the "as available" rates that is consistent with FERC's recent Order No. 872, as well as maintained the two-year variable rate offer, the Companies are amending their tariffs to reflect the distinct rate offers.

are eligible for capacity credits beginning in the first year of a utility's capacity need, and

- A new Marginal Cost Rates section discusses how such rates are developed and calculated at the end of each calendar month, for each hour of the month, and how Eligible QFs may receive the rate rates after executing a non-disclosure agreement.[101]

In addition, the Companies propose to reduce the monthly Administrative Charge (DEC) or Monthly Seller Charge (DEP) ("seller charges") to $3.00 per month for the smallest QFs, those with capacity of 15 kilowatts (AC) or less. The Companies have found that for such very small sellers, which only number about two dozen between both Companies, there are actual and potential instances where QFs can experience monthly invoices that require net payments to DEC or DEP despite sales of energy. To reduce the number of such instances where QFs are experiencing net payments, the Companies are offering to reduce the seller charges for this small number of customers. The Companies are not proposing an associated increase in the seller charges for other QFs to make up for the revenue loss.

In the Terms and Conditions for the Purchase of Electric Power, the Companies have revised Section 6 to use the Marginal Cost Rates as the benchmark for calculating early termination payments for the period on and after November 1, 2021, replacing the use of the Variable Rates for this purpose. In Section 9, there has been a change to reflect the

[101] To allow for necessary billing systems changes and to reduce complexity of the proposed as-available rate transition for customers, the proposed "as available" Marginal Cost Rates are to become effective only after a final Commission order approving Schedule PP.

Companies' new service regulation standard that a "Month" for billing purposes is 26-34 days.

VII. Modifications to Standard Offer PPA

The Companies have made limited revisions to their standard offer PPA forms presented in DEC's and DEP's respective Exhibit 3. The standard PPA forms now refer to the new Marginal Cost Rates and clarify that any automatic extension of the Agreement would use the as-available rates, which, in the Companies' proposal, would now mean the Marginal Cost Rates. The Companies are also removing a reporting requirement provision (section 6 of the PPA form) for the sake of clarity because it does not apply to Eligible Qualifying Facilities of 1,000 kW (1 MW) and under. This Section 6 requirement will continue to be used in non-standard offer PPAs for larger QFs. The Companies have also made limited clarifying revisions to the Capacity Hour Windows concept in the Exhibit A Energy Storage Protocol.

VIII. Notice of Commitment Forms for Standard Offer and Large QFs

FERC's regulations implementing PURPA provide QFs the option to "provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term[.]"[102] Both FERC and this Commission have held that a QF may form a "LEO" by committing itself to sell to an electric utility, resulting in either a contract or in a non-contractual, but binding, legally enforceable obligation.[103]

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[102] 18 C.F.R. 292.304(d)(ii).

[103] *2016 Sub 148 Order*, at 105 citing *JD Wind 1, LLC*, 129 FERC ¶ 61,148 at ¶ 25, *reh'g denied*, 130 FERC ¶ 61,127 (2010) ("[A] QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.").

Desiring an administratively-efficient process for QFs to establish non-contractual LEOs in North Carolina, the Commission first adopted a standardized Notice of Commitment form in the 2014 Sub 140 proceeding.[104] Since that time, QFs in North Carolina have been required to submit a Notice of Commitment Form in order to establish a LEO and to memorialize their commitment to sell the output of their generating facilities to the Companies.[105] In the *2016 Sub 148 Order*, the Commission directed the Companies to make certain modifications to the Notice of Commitment forms and approved separate forms and requirements, depending on whether the QF is eligible for the Companies' Schedule PP standard offer tariffs (1 MW_{AC} or less), or where the QF is greater than 1 MW_{AC} and requesting to negotiate a PURPA PPA with the Companies.[106] The Companies have only proposed limited non-substantive changes to the Notice of Commitment form since 2018.

In this proceeding, the Companies are proposing to update the Notice of Commitment forms to accomplish three primary objectives: (1) incorporate the new commercial viability and financial commitment requirements established in FERC Order No. 872; (2) align the Notice of Commitment Form with the now-approved queue reform process under the North Carolina Interconnection Procedures; and (3) update the non-standard offer Notice of Commitment Form to establish a more standardized and efficient process for QFs to proceed from Notice of Commitment Form to PPA.

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[104] *Phase II Sub 140 Order,* at 9 (Finding of Fact 24).

[105] *Id.; see also In the Matter of Cube Yadkin Generation, LLC, Complainant, v. Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, Order Granting Moton to Dismiss,* Docket Nos. E-2, Sub 1177 and E-7, Sub 1172, at 6. (July 16, 2018) (concluding that a QF's commitment to sell its output to a facility under PURPA through the use of the approved Notice of Commitment form [referred to as a LEO form] is a necessary prong in establishing a LEO).

[106] *2016 Sub 148 Order*, at 105-108.

<u>Order No. 872 Commercial Viability and Financial Commitment Requirements</u>

In Order No. 872, FERC adopted 18 C.F.R. 292.304(d)(3), which now requires new QFs to "demonstrate commercial viability and financial commitment to construct its facility . . . as a prerequisite to a qualifying facility obtaining a legally enforceable obligation."[107] The new regulations task state Commissions with determining the objective and reasonable criteria QFs must use to demonstrate commercial viability and financial commitment. FERC emphasized that these new requirements were "raising the bar to prevent speculative QFs from obtaining LEOs, and the associated burden on purchasing utilities, [while] not establishing a barrier for financially committed developers seeking to develop commercially viable QFs."[108] The new standard is also designed to ensure that that no electric utility obligation is triggered for those QF projects that are not sufficiently advanced in their development, and therefore, for which it would be unreasonable for a utility to include in its resource planning.[109]

FERC also explained in Order No. 872 that the criteria or factors established by State Commissions for QFs to demonstrate commercial viability and financial commitment should be in the control of the QF, and identified the following examples of factors that a state could reasonably require:

- <u>Site Control:</u> Require QF to demonstrate it is taking meaningful steps to obtain site control adequate to commence construction of the project at the proposed location.

[107] FERC Order No. 872, at ¶¶ 684-696.

[108] *Id.*, at ¶ 688.

[109] *Id.*, at ¶ 684.

- Interconnection: Require QF to demonstrate it has filed an interconnection application with the appropriate entity.
- Permitting and Zoning: Require the QF to demonstrate that it has submitted all applications, including filing fees, to obtain all necessary local permitting and zoning approvals.[110]
- Financial Commitment to Develop QF: Meet objective and reasonable milestones in the QF's development that can sufficiently demonstrate the QF developers' financial commitment in the QF development and allows utilities to reasonably rely on the LEO in planning for system resource adequacy.[111]

FERC also emphasized that states are in the best position to determine what specific factors would best suit the specific circumstances of that state, so long as they are objective and reasonable.[112]

The Companies have developed updated Notice of Commitment Forms that are designed to demonstrate the QF Seller's commercial viability and financial commitment to sell power to DEC or DEP. Attachment C to the Notice of Commitment Form requires the QF to show that it (i) has obtained a CPCN; (ii) for new QFs requesting to interconnect to the utility's system, the QF has met all requirements to enter the Definitive Interconnection Study Process under NCIP Section 4.4.1 and has executed a Definitive Interconnection System Impact Study Agreement pursuant to NCIP Section 4.4.5; (iii) has site control for the entire proposed term of delivery under a future PPA; and (iv) provides reasonable evidence and documentation of the QF's commitment to develop the project by including

[110] *Id.*, at ¶¶ 685-686.

[111] *Id.*, at ¶¶ 685-687.

[112] *Id.*, at ¶ 690.

a status update on permitting, procurement of any long lead-time materials, execution of third-party engineering, procurement and construction contracts to construct the facility, and execution of any third-party transmission agreements, if applicable. Each of these requirements are reasonable, objective and are within the control of the QF developer.

Alignment with Queue Reform

The Companies have also modified the Notice of Commitment Form to align with the new Definitive Interconnection Study Process, which restructures the traditional North Carolina Interconnection Procedures ("NCIP") Section 4.3 serial System Impact Study into a multi-step Cluster Study process under NCIP Section 4.4.7. A key objective of queue reform is to reduce the number of speculative projects entering the interconnection process through increasing study deposits, commercial readiness requirements and financial commitments for non-ready projects as they progress through the interconnection study process. These concepts generally align with the new commercial viability requirements to establish a LEO under FERC's PURPA regulations. For new QFs that are proposing to interconnect and sell and deliver power to DEC or DEP, the QF must demonstrate that it has (i) submitted an interconnection request to become an Interconnection Customer of the Company; (ii) paid both its study deposit and initial M1 financial security under NCIP Section 4.4.1; and (iii) executed a Definitive Interconnection System Impact Study ("DISIS") Agreement pursuant to NCIP Section 4.4.5. The interconnection-related provisions are all within the control of the QF and are reasonable and objective indicia of commercial viability for a new QF requesting interconnection to the DEC or DEP system.

The Companies’ updated Notice of Commitment Form also algins with the DISIS process as a binding Notice of Commitment and can be used to demonstrate project readiness at both the M1 and M2 readiness milestones.

Standardizing Process for QFs to proceed from Notice of Commitment Form to PPA

The Companies are also proposing to update the Notice of Commitment Form to provide a more standardized and streamlined process for QFs to progress from a Notice of Commitment Form to a mutually binding PPA. Historically, the Companies have not relied upon a QF’s submittal of a Notice of Commitment Form as providing sufficient indicia of commercial viability and financial commitment to sell and deliver power that the utility could reasonably rely upon the QF’s capacity in its future resource planning. Recognizing Order No. 872’s new emphasis on utilities being able to rely upon commercially viable and financially committed QFs in resource planning, the Companies have both expanded the requirements of the Notice of Commitment form, as discussed above, and have also modified the form to enable QFs to more efficiently provide all information that the Companies will need to develop an executable form of PPA that the QF could then be signed within a reasonable period of time. Specifically, Section 3 and Attachment B of the Large QF (those QFs not eligible for Standard Tariff) Notice of Commitment Form now establish a standardized process for the QF to provide all information that the Companies require to develop a negotiated QF PPA and commits that the Companies will deliver an executable PPA back to the QF within 30 days. The QF would then have a period of 90 days to work with the utility to finalize and execute the PPA, with this period being automatically extended to no earlier than 30 days after receiving a Facilities Study Agreement from the Company.

The updated Notice of Commitment Form for QFs up to 1 MW eligible for Schedule PP and larger QFs not eligible for the standard offer are set forth in <u>DEC/DEP Exhibit 6</u> and <u>DEC/DEP Exhibit 7</u>, respectively.

IX. Energy Storage System Retrofit Rates

In both the *2018 Sub 158 Order* and the Commission's June 14, 2019 *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony* in Docket No. E-100, Sub 101, the Commission directed the parties to address issues related to the addition of energy storage at an existing QF, including, but not limited to, developing a streamlined process for interconnecting energy storage systems to existing generation sites and organizing a stakeholder proceeding to address other related issues.[113] Through the stakeholder process, the Companies subsequently developed their Energy Storage System ("ESS") Retrofit Study Process and filed it with the Commission.

On August 17, 2021, the Commission ordered the Companies to, among other things, establish and file "the procedure for how a QF establishes eligibility for the avoided cost rate or methodology applicable to the output of the energy storage addition."[114] The Companies set out their proposal for this process in their September 29, 2021 Compliance Filing filed in both the Sub 158 and Sub 101 dockets.[115] While the Commission has not yet approved the Companies' proposed procedure, DEC and DEP committed to publish in the instant filing their respective 2, 3, 4, 5, 6, 7, 8, 9, and 10-year New ESS Retrofit avoided

[113] *2018 Sub 158 Order*, at 137 (Ordering Paragraph 31); *2020 Sub 101 Order*, at 65 (Ordering Paragraph 7).

[114] *Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations*, Docket No. E-100, Sub 101 (issued Aug. 17, 2021).

[115] *ESS Retrofit Compliance Filing*, Attachment C ("Procedure for Energy Storage System Retrofit at an Existing QF Generation Site to Establish Eligibility for Avoided Cost Rates"), Docket. Nos. E-100, Sub 101 and E-100, Sub 158 (filed Sept. 29, 2021).

cost rates available to Interconnection Customers proposing to retrofit an ESS at an existing generation site.

The Companies' proposed new ESS Retrofit avoided cost rates are set forth in DEC Exhibit 12 and DEP Exhibit 12, respectively, and the forecast data used to calculate each published levelized New ESS Retrofit avoided cost rate will begin January 1, 2023 and span the length of time specified for the particular year term of the New ESS Retrofit avoided cost rate. These rates will be available until November 1, 2023.

CONCLUSION

WHEREFORE, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC respectfully request that the Commission approve the Companies' respective updated Schedule PP avoided cost rates and terms and conditions, as presented in this Joint Initial Statement, and to provide any further relief the Commission deems to be just and reasonable and in the public interest.

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and Duke Energy Progress, LLC

VERIFICATION

STATE OF NORTH CAROLINA)
) DOCKET NO. E-100, SUB 175
COUNTY OF UNION)

The undersigned, Glen Allen Snider, being first duly sworn, deposes and says that he is Managing Director – Integrated Resource Planning and Analytics – Carolinas; that he has read the foregoing Joint Initial Statement and Proposed Avoided Cost Rate Tariffs of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC and knows the contents thereof; that the same are true of his own knowledge, except as to those matters stated on information and belief, and as to those matters, he believes them to be true.

Glen A Snider

Glen A. Snider

Signed and sworn to before me this day by Glen A. Snider
Name of principal

Date: October 29, 2021

Peggy Holton
Official Signature of Notary

Peggy Holton, Notary Public
Notary's printed or typed name

PEGGY HOLTON
NOTARY
(Official Seal)
PUBLIC
WAKE COUNTY, NC

I signed this notarial certificate on 10/29/2021 according to the emergency video notarization requirements contained in G.S. 10B-25.

Notary Public location during video notarization: Wake County

Stated physical location of principal during video notarization: Union County