Initial Statement of the Public Staff

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2021

Docket No. E-100, Sub 175

February 24, 2022

INTRODUCTION

Since the passage of the federal Public Utility Regulatory Policies Act of 1978 (PURPA) and the enactment of N.C. Gen. Stat. § 62-156 by the North Carolina General Assembly in 1979, the Commission has held biennial proceedings to determine the avoided cost rates of Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP, and together with DEC, Duke), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (DENC) (DEP, DEC, with DENC collectively, the Utilities), Western Carolina University (WCU), and Appalachian State University, d/b/a New River Light and Power Company (NRLP) and the terms and conditions under which the rates must be offered to generating facilities that qualify under PURPA and to those that are eligible for contracts under N.C.G.S. § 62-156.

Section 210 of PURPA, together with the regulations promulgated pursuant thereto by the Federal Energy Regulatory Commission (FERC), requires electric utilities to offer to purchase electric power from cogeneration and small power production facilities that obtain qualifying facility (QF) status under PURPA. For such purchases, a utility is required to pay rates that reflect the costs that it can avoid as a result of obtaining the energy and capacity from QFs, rather than generating the electricity itself or buying it from other suppliers.

The Public Staff's investigation of the Utilities' avoided cost filings has been thorough and comprehensive. A summary of our investigation is included within these comments. In the Issues and Concerns section, the Public Staff highlights several important matters that arose during its review. A summary of the Public Staff's recommendations is provided at the end of these comments.

ISSUES AND CONCERNS

USE OF AVOIDED COST IN NET METERING

On November 29, 2021, DEC and DEP filed a Joint Application for Approval of Revised Net Energy Metering Tariffs in Docket Nos. E-7, Sub 1214, E-2, Sub 1219, and E-2, Sub 1076 (NEM Tariffs). The Commission has requested comments from interested parties in Docket No. E-100, Sub 180. The Public Staff notes that this filing proposes that customers who export power are compensated at a Net Excess Energy Credit (NEEC), which is based upon avoided costs. Specifically, the NEEC as proposed is the two-year annualized rate, at the distribution level, for Uncontrolled Solar Generators.

The Public Staff is raising this issue because the calculation of the annualized rate is typically performed within the biennial avoided cost proceeding. The Public Staff does not wish to have the NEM Tariff proceeding become an avoided cost determination; as such, the appropriate methodology for calculating the avoided cost rate used for the NEEC should be decided in this docket. The Public Staff wishes to raise three issues regarding the NEEC calculation methodology.

First, the annualized rate proposed is a weighted average of the avoided energy and capacity rates in each pricing period.[1] The weight assigned to each rate is proportional to the number of hours that rate occurs during a given year, assuming a generator output profile that delivers constant energy in all hours of the year.[2] Given that most net metered facilities are solar, it may be appropriate to apply a solar profile, rather than a constant profile, to the annualized rate. This change, however, has a minor impact on the NEEC rate.

Second, the NEEC proposed by Duke is an average annual rate and does not change with the seasons. The Public Staff, however, believes it is appropriate to calculate seasonal NEEC rates for the summer and non-summer seasons, to reflect the difference in value associated with net metering exports and to align with the seasons in the time of use (TOU) rates schedules applicable to all NEM customers taking service under the proposed NEM Tariffs.[3] Using differing summer and non-summer rates will achieve some seasonal differentiation for exports while not overly complicating the tariff implementation.

Finally, Duke has proposed to use the two-year variable rate to set the NEEC. The variable rate does not include any avoided capacity credits. It may be

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[1] *See* Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Exhibit 5, filed November 1, 2021, in Docket No. E-100, Sub 175; *see also*, Joint Application of Duke Energy Carolina, LLC and Duke Energy Progress, LLC For Approval of Net Energy Metering Tariffs in Compliance with G.S. § 62-126.4 and House Bill 951 at 16, filed November 29, 2021, in Docket No. E-100, Sub 180.

[2] For example, in a typical year there are 341 hours that fall into the Summer Premium Peak pricing period. The weight assigned to the summer premium peak rate is 341 hours divided by 8,760 hours, or 3.9%. However, if a typical solar generator output profile is used, the weight assigned to the summer premium peak rate increases to 4.7%, as there are fewer than 8,760 total hours in the year with solar output.

[3] Duke proposes to require all new NEM customers beginning in 2023 to take service under a TOU rate schedule.

appropriate to use a longer-term rate, as net metered solar is included in Duke's IRPs as a reduction to its load forecast. As such, when determining the first year of need, Duke implicitly includes the capacity contribution from rooftop solar installations as if they are a designated resource. However, a 10-year term may be too long a period, as there is no contractual obligation for the net metered facility to operate for that term. To strike a balance between the proposed variable rate and a longer 10-year rate, the Public Staff proposes to utilize a 5-year rate, which, if approved, would be the basis for future NEEC calculations.[4] The Public Staff recommends that in future avoided cost filings, Duke explicitly calculate the NEEC for NEM Tariffs pursuant to this methodology.

The impact of making the three suggested changes is shown in Table 1 below.[5] The Public Staff believes that the slight increase in the complexity of the NEM Tariff due to incorporating seasonal rates is justified by the improved accuracy of export compensation. The Public Staff is soliciting input from intervenors and Duke on these proposed modifications, as well as its recommendation that each future biennial avoided cost proceeding include an explicit calculation of the NEM Tariff NEEC. The Public Staff recommends that the Commission direct Duke to make a supplemental filing providing a re-calculated annualized NEEC rate that is: i) weighted to a solar profile; ii) differentiated by season; and iii) based on the 5-year avoided cost rates.

[4] The Public Staff calculated a 5-year energy and capacity rate based upon Duke's Joint Initial Statement, Exhibit 2.

[5] These calculations are based on Sub 175 rates, as Duke has indicated it intends to refresh the NEEC as each avoided cost filing is approved. The NEEC filed in the NEM Tariff docket was based upon Sub 167 rates.

Table 1 – Duke's and Public Staff's Proposed NEM Tariff NEEC Rate			
(cents per kWh)	**Time Period**	**DEC**	**DEP**
As Proposed	All Year	3.81	3.91
With Public Staff Modifications (solar profile, 5-year, seasonal variation)	Summer	3.49	3.39
	Non-Summer	3.44	3.81

<u>INCLUSION OF CARBON COSTS IN AVOIDED ENERGY RATES</u>

In its December 31, 2014 Order Setting Avoid Cost Parameters, Docket No. E-100, Sub 140 (Sub 140) (Order on Inputs), the Commission concluded that the calculation of avoided costs should be based on "known and verifiable" costs, finding that the costs of carbon dioxide (CO_2 or carbon) emissions are not sufficiently certain to be included in avoided costs.[6] Further, the Commission ruled that the generation expansion plans used in the calculation of avoided energy should be based on Integrated Resource Plan (IRP) expansion plans that take into account only known and quantifiable costs.[7] The Commission reiterated its ruling in its December 17, 2015, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities (Sub 140 Order), finding that "DEC's and DEP's calculation of avoided energy rates utilizing generation expansion plan scenarios that were selected based on the inclusion of the CO_2 costs is inconsistent with the Commission's directives from the Order on Inputs."[8] In the last avoided cost proceeding, Docket No. E-100, Sub 167, the Commission again found that Duke's

[6] Order on Inputs, Finding of Fact 14 at 42-44.
[7] *Id.*, Finding of Fact 15 at 42-44.
[8] Sub 140 Order at 24.

calculation of avoided energy rates, using inputs from their 2020 IRPs that do not reflect a carbon price, is appropriate because the Commission has previously directed that only known and verifiable costs should be considered in the avoided cost rates.[9]

In their calculation of avoided energy rates in the instant docket, DEC and DEP utilize their Portfolio A from their 2020 IRPs filed in Docket No. E-100, Sub 165, which is the base case without carbon policy. The production cost model inputs used in the calculation of avoided energy rates do not include a carbon price, consistent with Portfolio A.

The Public Staff notes that on October 13, 2021, House Bill 951, Session Law 2021-165 (HB 951), was signed into law. Among other things, HB 951 created a program specific to Duke that required the North Carolina Utilities Commission (NCUC or Commission) to take all reasonable steps to achieve a 70% reduction in emissions of carbon dioxide emitted in the State from electric generation facilities owned or operated by Duke Energy from 2005 levels by the year 2030, as well as carbon neutrality by the year 2050.[10] The law requires the Commission to develop a Carbon Plan no later than December 31, 2022, to achieve the authorized reduction goals. Currently, Duke is required to file a proposed Carbon Plan on or

[9] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, *Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2020*, Docket No. E-100, Sub 167, at 7 (Aug. 13, 2021).

[10] The law also provides some flexibility, specifically allowing the Commission to delay compliance of the 2030 target by two years, or more, if necessary to maintain the adequacy and reliability of the electric grid or to provide additional time to allow for implementation of solutions that would have a more significant and material impact on carbon reduction.

before May 16, 2022, after conducting at least three stakeholder meetings by May 13, 2022.[11]

The Public Staff notes that the Carbon Plan has not yet been developed. HB 951 imposes a limit on total CO_2 emissions (mass cap) and does not impose a direct price on CO_2 emissions. However, a mass cap and a price on CO_2[12] are directly related to one another. In capacity expansion models, setting a mass cap will yield a model result with an implied price on carbon, which is indicative of the cost per ton of carbon abatement. Decreasing the amount of allowed emissions will increase the implied carbon price. Conversely, a modeler could set a price on carbon and find that a certain amount of carbon is emitted; a higher price on carbon would lead to fewer carbon emissions.[13] The increase in total system costs associated with carbon regulation, whether implemented via a mass cap or carbon price, is the total cost of carbon abatement.

The Public Staff has considered whether it is appropriate to require Duke to include carbon prices, or use an IRP Portfolio that includes carbon pricing, in setting avoided energy rates in this proceeding. The inclusion of a carbon price in the avoided energy rates is influenced by multiple factors, such as the current state

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[11] *See* Order Granting Extension of Time, Docket No. E-100, Sub 179 (Nov. 29, 2021).

[12] The term “price on carbon” or “carbon tax” are used interchangeably to indicate a direct charge that utilities must pay for each ton of carbon emitted.

[13] This dynamic plays out in most cap-and-trade carbon reduction schemes, with the Regional Greenhouse Gas Initiative (RGGI) being the closest example. RGGI first determines a total amount of carbon emissions that is allowed in any given quarter, which roughly determines the number of carbon allowances that will be made available to utilities. Next, there is a bidding process by which utilities purchase the required number of carbon allowances to comply with RGGI’s regulations. The market price of those carbon allowances becomes the carbon price that utilities must pay for their carbon emissions. All else equal, raising (or lowering) the amount of allowed carbon emissions, and the available carbon allowances, would decrease (or increase) the market price of carbon.

of Duke's Carbon Plan, the timing of biennial avoided cost filings, future solar procurements authorized by HB 951, and the extent to which the cost of carbon implied by the carbon cap is actually avoided by purchases from QFs. Not all of the total cost of carbon abatement is avoidable in the context of calculating avoided costs. For example, a portion of the implied cost of carbon derived from the Carbon Plan may include higher capital costs associated with the purchase or construction of new renewable generation facilities. Some of those costs may not be avoided when purchasing incremental renewable energy from QFs, and therefore, it may not be appropriate to include a price on carbon associated with capital investments as an input into the production cost model. The Public Staff will review the Carbon Plan and seek to make a determination in that docket of the appropriate avoidable cost of carbon, if any, that should be included in the calculation of avoided energy rates.

The Public Staff believes that the implied cost of carbon resulting from HB 951 cannot be accurately determined until a Carbon Plan is approved. As such, the Public Staff recommends that the Commission approve Duke's avoided energy rates using Portfolio A without a carbon price at this time, subject to other recommendations in these comments. However, once a Carbon Plan is approved and the avoidable cost of carbon, if any, is determined within those proceedings, the Public Staff recommends that the Commission direct Duke, in its next avoided cost filing, to use the approved Carbon Plan as the expansion portfolio and include the Commission-approved avoidable cost of carbon in its calculation of avoided energy and capacity rates, if appropriate. While new QF contracts do not grant

DEC or DEP the environmental attributes produced under the current purchase power agreement, the carbon-free QF power still displaces utility-owned carbon-emitting generation and could require compensation for its contribution towards Duke's statutory mandate to reduce carbon emissions. The question of environmental attributes will become more pertinent once Duke is seeking to comply with the carbon neutrality provisions of HB 951 beyond 2030, in which carbon offsets may be used to meet a portion of the carbon reduction goals.

DENC calculates the avoided energy rates utilizing its Alternative Plan B from its 2020 IRP filing in Docket No. E-100, Sub 165. Alternative Plan B is the least-cost plan that complies with all applicable state law within the planning horizon, including the Virginia Clean Economy Act (VCEA) and Virginia's membership in the Regional Greenhouse Gas Initiative (RGGI). The projected cost of RGGI carbon allowances is uncertain, and based on statements by Governor Youngkin, Virginia might not remain a member of RGGI,[14] but the existence of a RGGI carbon price is sufficiently "known and verifiable" based on current law.[15] Therefore, the Public Staff finds it is appropriate that DENC utilized generation expansion Plan B and included the cost of RGGI carbon allowances in the

[14] In December 2021, Virginia governor-elect Glenn Youngkin indicated he would push to withdraw Virginia from RGGI. On January 16, 2022, Governor Youngkin signed an executive order to direct the State Air Pollution Control Board to review options for withdrawal. See https://richmond.com/news/state-and-regional/govt-and-politics/youngkin-backs-off-plan-to-use-executive-power-to-remove-virginia-from-rggi/article_2f276193-af84-557d-a849-4443f0cb2351.html. In addition, on February 17, 2022, the Virginia House passed HB 118, which would withdraw the state from RGGI. The ultimate status of this proposed bill is uncertain.

[15] For example, RGGI auction clearing prices for past years are published online and available for review. Future carbon prices are forecast by external consultants. RGGI also forecasts future carbon allowance estimates for "control" or compliance periods, which directly influence the future price forecasts. See more information at https://www.rggi.org/.

production cost models that were used to calculate its avoided energy rates in this proceeding.[16]

<u>SUB 158 ISSUES</u>

On August 13, 2021, the Commission issued an Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing to commence the 2021 biennial avoided cost proceeding in Docket No. E-100, Sub 175 (Scheduling Order). The Scheduling Order noted that the Commission's April 15, 2020 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities issued in the 2018 Avoided Cost Proceeding, Docket No. E-100, Sub 158 (Sub 158 Order) set forth a number of additional issues to be addressed by the Utilities in their initial filings in this proceeding, including the following:

- real-time pricing tariffs;
- cost increments and decrements to the publicly available combustion turbine (CT) 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 QFs to provide ancillary services and appropriate compensation; and

[16] The cost of CO_2 imposed on Virginia (VA) generation by VA laws and regulations should be treated no differently than the cost of nitrous oxides (NOx) or sulfur dioxide (SO_2) imposed on VA generation by VA laws and regulations.

- the results of an independent technical review of the Astrapé Study solar integration services charge (SISC) methodology.

On October 30, 2020, in Docket No. E-100, Sub 167, upon the request of the Utilities, the Commission granted the request to conduct a streamlined proceeding for the 2020 avoided cost proceeding and to delay the Sub 158 Additional Issues until November 1, 2021 (Continuance Order). The Continuance Order required that the Utilities provide a timeline for addressing the Sub 158 Additional Issues and file updates at least every 45 days thereafter until the issues are fully addressed.

The Utilities filed eight 45-day progress reports in Docket No. E-100, Sub 167, on December 7, 2020; January 1, 2021; March 8, 2021; April 22, 2021; June 6, 2021; July 22, 2021; September 7, 2021, and October 22, 2021. The last progress report summarizes the status of the Sub 158 Additional Issues prior to the filing of proposed avoided cost rates in this docket. The Public Staff has worked closely with the Utilities to reach agreement on as many of these issues as possible prior to the Sub 175 filings, and will address these issues below as warranted.

On August 13, 2021, the Commission issued its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 167 (Sub 167 Order). The Commission found that the Utilities have complied with the requirements of the Sub 158 Order in filing progress updates on the Sub 158 Additional Issues. On November 1, 2021, Duke and DENC made their Sub 175 filings consistent with the Scheduling Order and the Continuance Order.

<u>REAL-TIME PRICING TARIFFS</u>

The Public Staff has worked with Duke on the development of real-time pricing tariffs. DENC offers a real-time pricing tariff in its schedule 19-LMP. Because Duke is not a member of a Regional Transmission Organization (RTO), it does not have access to publicly available hourly marginal pricing, so developing a real-time pricing tariff is more complex. Prior avoided cost proceedings have determined that a QF not committing to sell and deliver all of its power to Duke receives the variable rate for the power it delivers. This variable rate is the same rate that applies to a QF that enters into a two-year contract with Duke to sell and deliver all of its power.

In its application in this proceeding, Duke refers to FERC Order No. 872[17] and the additional flexibility provided to states when setting avoided energy rates. Duke proposes to incorporate real-time pricing and Order No. 872 by creating a new "as-available" rate schedule for QFs that decline to commit to sell and deliver power to Duke under a fixed term. QFs that sell power under the as-available rates will be compensated based on Marginal Cost Rates that are calculated ex-post at the end of the month.[18] This rate schedule should ensure that QFs are paid actual marginal costs, rather than market forecasts. Duke would continue to offer its two-

[17] Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Act of 1978, Order No. 872, 172 FERC ¶ 61,041 (2020), *order on reh'g*, Order No. 872-A, 173 FERC ¶ 61,158 (2020).

[18] Duke currently uses this same methodology to calculate transmission and wholesale imbalance billing rates.

year variable rates, which would require a QF to contractually obligate itself to sell and deliver power for a two-year term.

The Public Staff supports this proposal because it will reduce overpayment risk to QFs that do not contractually obligate themselves to sell and deliver power to Duke for a fixed term. As of December 2021, only three small hydro QFs are selling power to Duke under "as-available" rates, so the anticipated impact of this proposal will be minimal.

COST INCREMENTS AND DECREMENTS TO THE PUBLICLY AVAILABLE CT COST ESTIMATES

The Public Staff agrees with both DENC's and Duke's utilization of publicly available CT costs and the economy of scale adjustments. The Energy Information Administration (EIA) data is for a single CT,[19] and utilities will typically plan to build multiple CTs at a single site, so the economy of scale adjustments are reasonable. In the previous avoided cost docket, the Public Staff observed that a brownfield site (location of existing, or previously existing, generation) cost decrement should be applied, given the historic build out of more recent CTs at brownfield sites.[20] Through multiple discussions with the Utilities, it is the Public Staff's current understanding that there is no certainty of where future CTs may be built, and the peaker method relies upon the concept of a "hypothetical" CT.[21] While it is likely

[19] *See* U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2021* at Table 2 (p. 3) (February 2021), available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf (last visited January 31, 2022).

[20] *See* Public Staff Initial Comments in Docket No. E-100, Sub 158, at 6.

[21] The "proxy methodology" for avoided cost rates would consider the actual cost of the next avoidable unit the utility plans to build. The Utilities do not currently use the proxy method.

that new CT generation will be built at a brownfield site, a brownfield cost decrement is not appropriate for inclusion in the calculation of avoided capacity rates at this time.

The Public Staff also notes that in developing the CT costs to be used as the basis for the calculation of avoided capacity rates, both Duke and DENC independently calculated adjustments[22] to the published EIA data. Duke's calculations yielded a 6.7% adjustment, and DENC's calculations yielded a 7.5% adjustment. Both Duke and DENC recommend using an average adjustment of 7.0% to determine the appropriate CT costs. The Public Staff finds this adjustment to be reasonable.

THE USE OF OTHER RELIABILITY INDICES, SPECIFICALLY THE EUOF, TO SUPPORT DEVELOPMENT OF THE PERFORMANCE ADJUSTMENT FACTOR (PAF)

The Public Staff agrees with both DENC and Duke's proposed PAF adjustment. Each utility utilized a weighted EUOF (WEUOF) metric for its respective generation fleet. The Public Staff supports the use of the WEUOF metric for both Utilities, which should create a uniform calculation methodology that can be used in the future.

The Public Staff has only one recommendation on the PAF calculation for future avoided cost filings. The WEUOF is calculated using data from the Generator Availability Data System (GADS). This system and its reporting

[22] *See* "CT Cost Calculation" section for more detail on the cost decrements applied by the Utilities.

requirements are maintained by the North American Electric Reliability Corporation (NERC). At this time, GADS does not require solar generation information reporting; therefore, Duke and DENC do not report outages from their solar generation facilities into GADS. Thus, solar facilities are excluded from the calculation of the WEUOF. Currently, solar outage data is unlikely to impact the WEUOF and PAF, but Duke and DENC are subject to carbon reduction legislation that explicitly directs them to build or acquire utility-owned solar assets.[23] As such, the Public Staff expects that solar and wind outage data will be increasingly important in the future calculation of PAFs. The Public Staff recommends that the Commission direct Duke and DENC to address the inclusion of solar and wind generator outage data in the calculation of the PAF in their next avoided cost filings, including the current status of outage reporting requirements set by NERC.

THE EXTENT OF BACKFLOW AT SUBSTATIONS AND THE LINE LOSS ADDER

The Public Staff supports DENC continuing to exclude a line loss adder[24] from the standard offer avoided cost rate, given the high backflow at DENC's substations. In contrast, the Public Staff supports Duke's continued inclusion of the line loss adder for the standard offer avoided cost rate given the current subscription ratio of distribution connected generation to Duke's distribution

[23] HB 951 mandates that 55% of the new solar generation selected by the Commission in its Carbon Plan shall be utility-owned facilities. The VCEA requires that up to 16,100 MW of utility-owned and operated solar and onshore wind facilities be found to be in the public interest, among other provisions encouraging the construction and purchase of solar generation facilities by DENC.

[24] Typical centralized generation experiences system losses as energy moves through the transmission system, transformers, and distribution system. Generation located on the distribution system would not experience the same losses. The line loss adder accounts for the reduction in losses associated with generation on the distribution system by increasing avoided energy rates.

system. Duke also proposes an objective methodology to evaluate the potential for backflow (and the inclusion or exclusion of the line loss adder) for negotiated contracts. If the substation that serves the QF has distributed energy resource (DER) backflow greater than or equal to 50%,[25] or if the addition of the QF would cause the DER backflow to become greater than or equal to 50%, the QF will not receive a line loss adder. The Public Staff finds this proposal reasonable.

THE POTENTIAL FOR QUALIFYING FACILITIES TO PROVIDE ANCILLARY SERVICES AND APPROPRIATE COMPENSATION

In the Sub 158 proceeding, Duke, the Public Staff, and certain other intervenors discussed how some QFs may be capable of providing ancillary services, such as frequency regulation or spinning reserves, to the grid, potentially at a lower cost than Duke's own resources, and highlighted some of the challenges associated with implementing QF compensation for these services.[26] Since then, the Public Staff has had numerous discussions with intervenors and Duke to discuss what, if any, ancillary services might be provided by QFs, and whether it is reasonable and cost effective for Duke to procure these services from QFs within the context of PURPA. Outside of some limited contingency reserve arrangements, the Public Staff is not aware of any other regulated utility in the country, operating outside of an RTO or Independent System Operator (ISO), that procures ancillary services from a third party power supplier. The Public Staff notes that while

[25] The DER backflow percentage 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. Duke Joint Initial Statement, at 31.

[26] *See* Reply Comments of the Public Staff, Docket No. E-100, Sub 158, at 23.

PURPA's mandatory purchase obligation does not extend to ancillary services, it also does not prohibit the procurement of ancillary services from QFs.

At a high level, the Public Staff believes that as Duke procures additional renewable generation to comply with its Carbon Plan, some ancillary services may be provided at least cost from inverter based resources (IBRs) such as solar PV, both with and without energy storage.[27] However, the Public Staff also acknowledges Duke's concerns with implementation of such a program, particularly given the relatively small amount of ancillary services required at any given time.[28] In discussions with intervenors, renewable energy developers have pointed to three specific ancillary services that are best suited to come from IBRs: spinning reserve, frequency regulation, and Volt-VAR support.

One of the most significant challenges to the provision of ancillary services from QFs is that ancillary services often require generators to produce less energy and capacity because some output is withheld to maintain the ability to ramp up, or is decreased following a ramp down signal. QFs seeking to provide ancillary services would therefore be trading revenue from energy and capacity for revenue from ancillary services. Based on the Public Staff's understanding of the typical prices for ancillary services in RTOs and ISOs, the rates for ancillary services are

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[27] The ability of standalone solar to provide certain ancillary services, including spinning reserves, load following, voltage support, ramping, frequency response, variability smoothing, and frequency regulation for power quality, was demonstrated at a 300 MW solar facility in the California Independent System Operator's footprint. Gevorgian, Vahan, Mahesh Morjaria, et al. 2017. *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5D00-67799. https://www.nrel.gov/docs/fy17osti/67799.pdf

[28] *See* Duke Joint Initial Statement at 35-37.

generally much lower than the rates for energy and capacity.[29] Unless QFs can simultaneously provide energy, capacity, and ancillary services, it is unlikely that QFs would choose to provide ancillary services except for the few hours of the year where ancillary service prices are high. Without knowing Duke's ancillary service costs, it is difficult to determine the degree to which procuring ancillary services from QFs could provide savings to ratepayers.

Therefore, the Public Staff takes the position that it is not appropriate at this time to compensate QFs for ancillary services beyond the increment provided to QFs that are able to avoid Duke's SISC by smoothing their volatility. The Commission, Public Staff, intervenors, and ratepayers, however, would benefit from a more detailed understanding of the technical ability to procure ancillary services from IBRs and the associated costs. The Public Staff solicits feedback from Duke, DENC, and other intervenors on the potential benefits of initiating a proceeding to investigate this matter and potentially establish a pilot program to procure a small amount of ancillary services from IBRs, either through the establishment of a limited competitive solicitation from QFs, or a pilot program at one of Duke's or DENC's utility-owned solar sites.

THE RESULTS OF AN INDEPENDENT TECHNICAL REVIEW OF THE ASTRAPÉ STUDY

[29] For example, PJM's weighted average cost for regulation in the first nine months of 2021 was $25.37 per MW, an increase from $15.59 per MW in 2020. See Monitoring Analytics "PJM State of the Market – 2021" Report, accessed at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021.shtml (accessed February 4, 2022). In addition, generators that provide ancillary services in organized markets are typically generators that do not clear the day ahead real-time market. QFs do not participate in any day ahead markets.

SISC METHODOLOGY

In the Sub 158 Order, the Commission directed Duke to submit the SISC methodology to an independent technical review committee, and to include the results of that review and any revisions to the methodology in its 2020 biennial avoided cost proceeding.[30] Duke established the technical review committee (TRC) in early March 2021, enlisting The Brattle Group (Brattle) to moderate the meetings and publish reports of the findings. Pursuant to the Sub 158 Order, the TRC consisted of technical experts from the Pacific Northwest National Laboratory, the National Renewable Energy Laboratory, and Lawrence Berkeley National Laboratory. The Public Staff and the South Carolina Office of Regulatory Staff participated as regulatory observers. Duke's technical staff also participated in the meetings, as needed, to address specific questions raised by the TRC. Technical staff from Astrapé also participated. The first TRC meeting was on March 2, 2021, and a total of eleven meetings occurred between March and September 2021.

The TRC Report is Exhibit 10 to Duke's Joint Initial Statement, and the 2021 Astrapé Study updating the SISC values is Exhibit 11. The Public Staff has reviewed both the TRC Report and the 2021 Astrapé Study. As an initial matter, the Public Staff found the technical experts who were engaged in the review process to offer relevant material feedback to the methodology and inputs. The TRC also addressed matters raised by intervenors in the Sub 158 proceeding and submitted to the TRC on March 30, 2021, by the Southern Environmental Law

[30] Sub 158 Order at 95.

Center on behalf of the Southern Alliance for Clean Energy (SACE), North Carolina Sustainable Energy Association, and Carolinas Clean Energy Business Association. The TRC Report provides an in-depth discussion of the specific issues discussed during the TRC meetings and addresses how each recommendation from the TRC is incorporated into the 2021 Astrapé Study. Overall, the TRC found that the estimated cost of reserves is reasonable, given the size of DEC and DEP relative to PJM Interconnection, L.L.C. (PJM) (the competitive market the TRC used as a benchmarked), and given the "relative inflexibility"[31] of Duke's generation fleet.[32] The Public Staff highlights several significant SISC methodology changes below.

A major criticism of Duke's proposed SISC methodology in the Sub 158 proceeding was that DEC and DEP were modeled separately, with no ability to rely on each other, or other utilities in the Eastern Interconnection, to meet intra-hour net load variations (the "island" case).[33] The TRC believes that the Joint Dispatch Agreement (JDA) allows DEC and DEP to share load following reserves at least cost in the event of intra-hour net load variations, and as such, the Astrapé Report includes a SISC calculated under the JDA assumptions. In its Joint Initial

[31] The "relative inflexibility" refers to the TRC's findings that Duke's block-loaded CTs and pumped hydro units were "less flexible than in other systems." The TRC further concluded that "barring potentially expensive upgrades to the units, their limited flexibility appears to reflect legitimate constraints on their operation and are correctly represented in the simulations to estimate the SISC." DEC/DEP Exhibit 10, TRC Report, at IV-11.

[32] *Id*. at IV-13.

[33] *See* Initial Comments of the Public Staff, Docket No. E-100, Sub 158 at 36 and 39.

Statement, Duke proposes to utilize the SISC derived under the JDA assumptions,[34] which the Public Staff finds reasonable and appropriate.

Another significant issue in the Sub 158 proceeding was Astrapé's use of the Loss of Load Expectation (LOLE) flexibility standard, which was an approximation of NERC reliability standards. In the Sub 158 proceeding, load following reserves were added until the system LOLE was equal to 0.1 flexibility violations per year. Some intervenors raised significant concerns with this approach,[35] as it attempted to model NERC reliability standards without also modeling the entire Eastern Interconnection, which is critical to interpreting whether a NERC reliability standard has been violated.[36] The 2021 Astrapé Report focuses on returning the system to pre-solar levels of reliability, rather than on incorporating NERC reliability standards into the model. The TRC agreed with this approach, finding that it was a significant improvement that would "better represent actual system conditions and operations."[37] The Public Staff agrees.

Another improvement over the 2018 Astrapé Study is the targeted approach to adding load following reserves. In the 2018 Astrapé Study, the load following reserves added to meet the LOLE flexibility standard were added in all hours of the day. In the 2021 Astrapé Study, load following reserves are added whenever

[34] Duke Joint Initial Statement at 34.

[35] *See* Docket No. E-100, Sub 158, Initial Comments of SACE, Attachment A at 2.

[36] NERC reliability standards, such as CPS1 and the Balancing Authority ACE Limit (BAAL), are based on the area control error (ACE). The ACE is a function of power inflows and outflows from the area being studied, and is influenced by frequency deviations from the 60 Hz standard. Without an understanding of system frequency, or of all inflows and outflows, NERC standards that depend upon ACE cannot be accurately modeled.

[37] Duke Joint Initial Statement, Exhibit 10 at IV-18.

they are most likely needed (in hours of high solar volatility). The TRC agreed with this change and stated that adding load following reserves only when solar volatility is a factor would better represent actual system conditions and operations.[38] The Public Staff agrees.

Finally, the TRC considered whether it was appropriate to include the effects of the proposed Southeastern Energy Exchange Market (SEEM) in calculating the SISC.[39] The SEEM proposes to facilitate 15 minute trading between Duke and neighboring utilities, without the need to pay for transmission wheeling charges. As proposed, trading schedules would be locked in five to ten minutes before the 15 minute trading period, which implies that SEEM could respond on a 20 to 25 minute basis to help balance solar volatility between SEEM members. The TRC determined that because the design, implementation, and actual operations of the SEEM are still uncertain, incorporating SEEM into the Astrapé Study would be at least partially speculative. In addition, the TRC stated it was not certain that the SEEM will help balance solar volatility, as it is not clear how much solar volatility will truly be resolved 20 to 25 minutes before real-time. For these reasons, the TRC recommended considering the effects of SEEM in the next estimation of the SISC after the exchange is implemented and operational

[38] Duke Joint Initial Statement, Exhibit 10 at III-13.

[39] The SEEM Platform Agreement went into effect as an operation of law on October 12, 2021, and parties have appealed the decision to the D.C. Circuit Court of Appeals where it is currently pending. The corresponding OATT revisions have been accepted and Duke and other SEEM members are required to make an informational filing 30 days prior to SEEM's Commencement Date to update the effective date of the OATT revisions. No SEEM member has made the informational filing at FERC at the time these comments were filed.

experience has been gained.[40] The Public Staff agrees, and recommends that Duke consider the effect of the SEEM on the calculation of the SISC in any avoided cost filings that occur six months or more after SEEM operations commence.

PROPOSED RATES[41]

SUMMARY OF AVOIDED COST RATES

In past biennial proceedings, the Commission has consistently approved the component or "peaker" methodology for the Utilities. Under this methodology, avoided capacity costs are estimated using the capital costs of the lowest-cost capacity option available to the utility, typically a peaking unit (e.g., a CT). Avoided energy costs are estimated using a cost simulation model to analyze marginal system running costs with and without a block of QF power. In Docket No. E-100, Sub 106 (2006 proceeding), the Commission approved the locational marginal pricing (LMP) method for Dominion North Carolina Power (now DENC) in addition to the peaker method. The LMP method is based on market clearing prices of power in the market operated by PJM.

At this time, the Public Staff supports the use of the peaker methodology for both Duke and DENC. However, the Public Staff observes that there may come a time when the peaker methodology is not appropriate for use in North Carolina. As utilities seek decarbonization, generation will increasingly come from renewable resources, such as wind and solar, that have high capital costs and low variable

[40] Duke Joint Initial Statement, Exhibit 10 at III-7.

[41] For ease of comparison, the Public Staff uses the avoided capacity rates and avoided energy rates for QFs interconnected to the distribution system. The rates for QFs interconnecting at the transmission level can be calculated by applying the appropriate adjustment for line losses.

costs. All else equal, this will tend to depress avoided energy rates. The Utilities, however, continue to use the cost of a CT to determine the avoided cost of capacity. In a future low-carbon scenario, peaking capacity may come from renewable resources and energy storage. For example, DENC's 2021 IRP Update Alternative Plans B and C have no CTs built during the planning horizon.[42] At some point, the Public Staff believes it may be appropriate to either look to other resources to determine the avoided cost of capacity or adopt a new methodology which reflects the changing energy landscape.

In its filing, DENC proposes two avoided cost rate schedules, Schedule 19-LMP based on LMPs and Schedule 19-FP based on the peaker method. Schedule 19-FP offers QFs fixed levelized avoided energy and avoided capacity payments for variable and 10-year terms.[43]

The Utilities have generally calculated the two-year and ten-year capacity and energy rates in the same manner as approved in Docket No. E-100, Sub 158 (2018 Proceeding or Sub 158) and in the 2020 Avoided Cost Proceeding, Docket No. E-100, Sub 167 (2020 Proceeding or Sub 167). The impact of the Utilities' proposed changes in avoided energy and capacity rates is best shown by comparing the utilities' proposed rates with their currently approved annualized rates, which assume QF generation during all of the on-peak and off-peak energy and capacity hours as identified in their rate schedules.

[42] *See* DENC's 2021 IRP Update, filed on September 1, 2021, in Docket No. E-100, Sub 165 at 5.

[43] Initial Statement and Exhibits of Dominion Energy North Carolina at 3, filed on November 1, 2021, in Docket No. E-100, Sub 175.

The annualized proposed avoided capacity and avoided energy rates assume that a QF operates for all of the prescribed on-peak and off-peak hours for both energy and capacity credits and are interconnected at the distribution system. The Utilities' total annualized 10-year energy rates and capacity rates are shown in Table 2 below, which also contains rate comparisons to the rates approved in the 2020 Proceeding.

Table 2: 10-year Annualized Energy and Capacity Rates (cents/kWh) & Percent Change from 2020 Approved Rates[44]

	DEC		DEP		DENC	
	2021 Proposed Rate	% Change	2021 Proposed Rate	% Change	2021 Proposed Rate	% Change
Annualized Energy Rate	3.47	23%	3.54	26%	2.543	-8%
Annualized Capacity Rate	0.26	-33%	0.55	-47%	0.516	-2%
Combined Total Rate	3.73	17%	4.09	22%	3.059	-7%

Figure 1 below is a graph of the approved combined avoided costs for the Utilities from 2002 through 2020 and the proposed annualized avoided cost rates for 2021.

[44] The energy rates reflect rates applicable to uncontrolled solar (Duke) and intermittent resources (DENC), and therefore include the SISC (Duke) and Re-Dispatch Charge (DENC).

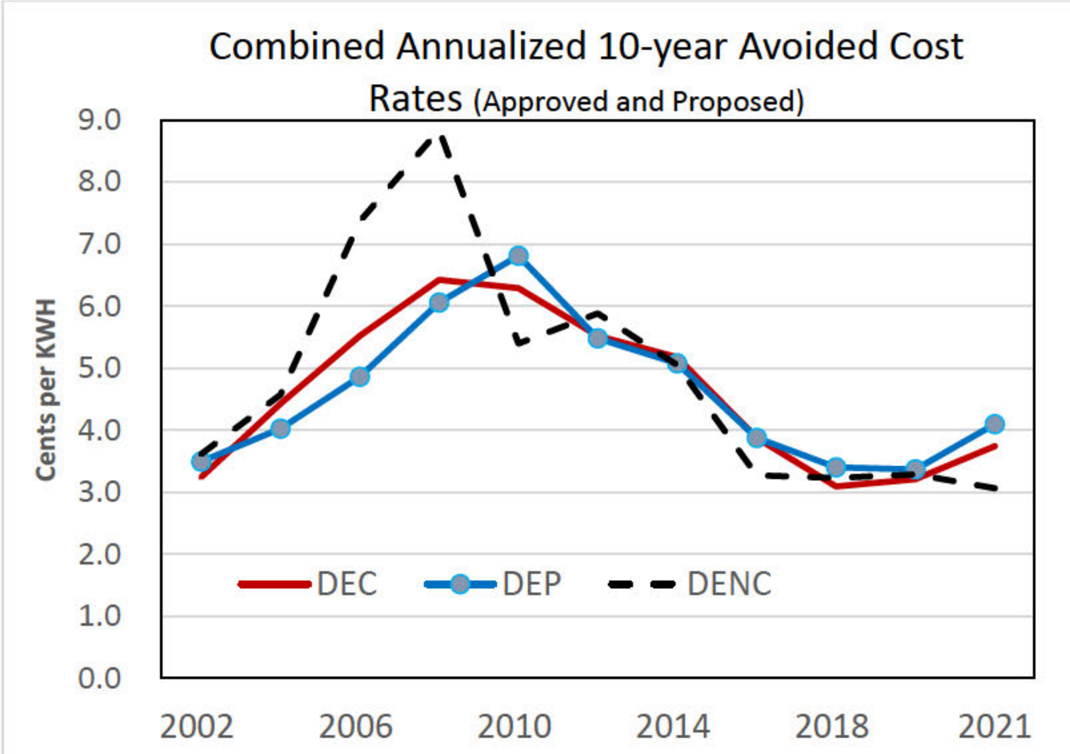

Figure 1: Combined Annualized 10-year Avoided Energy and Capacity Rates (Approved and Proposed)

<u>AVOIDED COST OF CAPACITY</u>

<u>First Capacity Need</u>

The Commission's October 11, 2017 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 148 (Sub 148 Order) found that avoided capacity value should be recognized beginning with the year that the utility's most recently filed IRP forecast shows a capacity need consistent with N.C.G.S. § 62-156(b)(3), as amended by S.L. 2017-192 (House Bill 589).[45] In the Sub 158 Order, the Commission found that it is appropriate for an electric utility to update its avoided capacity calculations to reflect any changes

[45] Sub 148 Order at 10.

in the utility's first year of avoidable capacity need for negotiated contracts and for use in the Competitive Procurement of Renewable Energy (CPRE) Program and

> [b]eginning with the 2020 IRP, the Commission finds that it is appropriate for the Utilities to include a specific statement of undesignated capacity need that is avoidable by QFs in order to remove uncertainty surrounding the exact year of capacity need and to provide a clearer standard for all parties in various regulatory proceedings, especially the next biennial avoided cost proceeding.[46]

The Utilities' proposed avoided capacity rates provide for the payment of avoided capacity costs only when a future capacity need can be avoided. The first year of need is based upon the load forecasts utilized in each Utility's most recently filed IRP, which itself includes forecasts of behind-the-meter rooftop solar adoption and electric vehicle adoption. For DEC, its filed 2020 IRP indicates that the first need to be avoided is in 2026; however, due to the approval of DEC's Integrated Volt Var Control (IVVC) program,[47] IVVC capacity is no longer an undesignated resource. The inclusion of 175 MW of IVVC capacity as a designated resource delays DEC's first year of need to 2028.[48] DEP's 2020 IRP indicates that the first need to be avoided occurs in 2024.[49] DENC's Corrected 2021 IRP shows the first deferrable capacity need in 2026.[50] The calculation of avoided capacity rates for each utility reflects the present value of avoided capacity costs beginning in its first year of need for all resources except certain QFs fueled by swine waste, poultry

[46] Sub 158 Order at 40.

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

[48] Duke Joint Initial Statement at 16.

[49] *Id*.

[50] DENC Corrected 2021 IRP Addendum 5, filed January 7, 2022, Docket No. E-100, Sub 165.

waste, and certain existing hydro power QFs less than 5 MW. The Public Staff finds the first year of need for each utility to be reasonable and based upon the most recently filed IRP.

<u>CT Cost Calculations</u>

The projected capital cost for an installed CT is the factor that has the most impact on the avoided capacity rate. In the Sub 140 Order on Inputs, the Commission concluded that:

> [b]ecause the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding … the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data. Data on the installed cost of CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.[51]

Duke and DENC used publicly available information from the EIA specific to Region 16 (SERC Reliability Corporation / Virginia-Carolinas SRVC) to provide the overnight capital cost[52] estimate for a single industrial Frame CT (F-Class CT) in simple-cycle configuration on a greenfield (new construction) site as a starting point. The Utilities then evaluated an economies of scale adjustment that takes into consideration common plant items (e.g., land costs, metering station, administration building) that can be allocated to more than a single CT. The Public Staff agrees with Duke's and DENC's approach in this case on evaluating, calculating, and applying an adjustment to the EIA published data. Simplified, the

[51] Sub 140 Order on Inputs at 48.

[52] Overnight capital costs are the capital costs assuming the plant could be built "overnight", with no financing costs.

EIA data utilizes a single CT, while the Utilities model in their IRPs a site comprised of multiple CTs with common or shared plant. The Utilities' approach in this case aligns with IRP planning and typical CT build-out in each of the Utilities' respective generation fleets.

Table 3 includes each Utilities' proposed CT overnight costs ($ per kW) compared to the costs approved in the 2020 Proceeding. These rates reflect the average 7.0% negative adjustment to EIA cost estimates previously discussed. The CT costs per kW are the single largest component of the Annual Capacity Costs per kW shown in Table 3. These costs are then grossed up to account for revenue requirements, allowance for funds used during construction (AFUDC), and a multi-year construction schedule. The reduction in Duke's costs is largely caused by a 9% reduction in EIA's CT cost estimates and an increase in downward adjustments reflecting economies of scale. DENC's costs increase, however, is partly due to DENC's use of EIA data in the development of its CT costs in this proceeding. In the 2020 proceeding, DENC utilized cost data published from a Brattle report combined with actual costs from its Greensville combined cycle power plant.

Table 3: CT Overnight Costs ($/kW)		
	2020	2021
DEC	$713	$619
DEP	$713	$619
DENC	$593	$616

An important factor used by Duke in the determination of avoided capacity rates is the real or inflation-adjusted fixed charge rate. Duke's real fixed charge rate includes the discount rate (which includes each company's allowed cost of equity), projected inflation rate, depreciation costs, insurance rates, property taxes, and income taxes. Multiplying the installed cost by the real fixed charge rate produces the annual carrying cost of the CT.

The reductions in DEC's and DEP's real fixed charge rate is largely attributed to the lower cost of capital established in their recent general rate case proceedings. DEC's real fixed charge rate reflects its approved lower overall cost of capital from its 2019 rate case (Docket No. E-7, Sub 1214), AFUDC rates, and state and federal tax rates. DEP's real fixed charge rate includes its lower overall approved cost of capital from DEP's 2019 rate case (Docket No. E-2, Sub 1219). Table 4 includes the approved 2020 fixed charge rates and the proposed rates for the 2021 Proceeding.

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Table 4: Duke's Real Fixed Charge Rates		
	[redacted]	[redacted]
DEC	[redacted]	[redacted]
DEP	[redacted]	[redacted]

[END CONFIDENTIAL]

Similar to the real fixed charge rate methodologies adopted by DEC and DEP, DENC's levelized economic carrying charge rate is calculated over the full book life of the CT and underlies the determination of DENC's avoided capacity rates. The increase in the economic carrying charge encompasses both a decrease in the discount rate and an increase in DENC's installed cost of capacity relative to the 2020 cost. Table 5 shows DENC's proposed 2021 economic carrying charge rate compared to the rate approved in the 2020 Proceeding. The economic carrying charge rate includes a 6.46% discount rate (which includes a weighted average of the North Carolina and Virginia jurisdictional allowed returns on equity), a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** projected inflation rate, depreciation costs, insurance rates, property taxes, and income taxes.

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Table 5: DENC's Economic Carrying Charge Rate		
	[redacted]	[redacted]
DENC	[redacted]	[redacted]

[END CONFIDENTIAL]

The Utilities included fixed O&M costs, the primary cost component of which is staff labor. The remaining costs include maintenance and minor repairs and administrative costs. Table 6 shows the Utilities' approved cost rates for fixed O&M per kW in 2020, and the approved cost per kW in 2021.

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Table 6: CT Fixed O&M Expenses Adjustment		
	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

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Table 7 shows the PAF the Utilities applied for all other QFs. The Utilities used five years of historic generation outage information while taking into consideration maintenance and forced outages that occur in alignment with the peak period months of the respective utility. As agreed upon by the Public Staff, Duke, and DENC, the WEUOF metric was used to calculate the PAF.

Table 7: Utilities' PAFs	
	All QFs
DEC	1.04
DEP	1.04
DENC	1.07

Table 8 shows DEC's and DEP's adjustments for marginal on-peak distribution and transmission line losses, which support the line loss adjustment. At this time, QFs located in DEC's and DEP's service areas are not as geographically concentrated as in DENC's service area, and the level of backflow into their transmission systems is not enough to offset the avoided cost benefits from reduced line losses for standard offer-eligible QFs. In the Sub 167 Order, the Commission found that power backflow on substations in DENC's service territory from solar generation on the distribution grid was high enough that avoided line loss benefits associated with distributed generation have been reduced or negated, and it was appropriate that DENC not include a line loss adder in its standard avoided cost payments to solar QFs on its distribution network.

The Public Staff finds that DEC's and DEP's loss adjustment factors shown in Table 9 are consistent with previous biennial proceedings. Given the continued increased backflow on DENC's transformers, the Public Staff finds that an adjustment for line losses is not warranted at this time.

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Table 8: Marginal On-Peak Distribution and Transmission Loss adjustments		
	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

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To determine the avoided capacity cost rates for all other QFs, Duke used the combination of the annual CT carrying costs plus fixed O&M and all the adjustments including the impact of the PAF. This calculation produces an annual capacity cost which, when divided by the megawatt (MW) rating of the CT, yields a levelized annual capacity cost ($/kW) shown below in Table 9. This annual capacity cost forms the basis for the avoided capacity costs that are utilized to evaluate the cost effectiveness of Demand Side Management and Energy Efficiency programs.

The decreases in DEC's and DEP's annual capacity costs were, in part, due to the previously discussed 7% downward adjustment from EIA's estimated cost per kW. As noted previously, the Commission directed meetings led to more homogenous installed costs between Duke and DENC due to the use of the same EIA CT cost estimate across the Utilities, which contributed to an increase in DENC's annual capacity cost per kW. [**BEGIN CONFIDENTIAL]**

Table 9: Annual Capacity Costs ($/kW)		
	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

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<u>Avoided Capacity Rates</u>

The annual capacity costs are levelized by determining the present value of the annual CT capacity costs and multiplying them by a 10-year annuity factor. Using the present values of the future avoided capacity costs, the Utilities generally continued the rate structure introduced and approved in the 2020 Proceeding. The only significant change is that both DEC and DEP no longer offer capacity payments in winter evening hours, reflecting the continued shift of loss of load risk to the winter morning hours, as demonstrated in the 2020 Astrapé Resource

Adequacy Study filed in the 2020 IRP Proceeding (2020 Resource Adequacy Study).

Table 10 below provides DEC's proposed ten-year levelized avoided capacity rates (cents/kWh) during the summer and winter months. QFs do not receive any capacity payment under variable or as-available rates. In addition, the avoided cost of capacity has dropped significantly; the levelized avoided capacity rate for solar generators is reduced by 33% and their summer capacity rate is reduced by 74%. The main drivers of DEC's avoided capacity rate reduction are two fewer years of needed capacity due to IVVC, a reduction in CT costs relative to the 2020 Proceeding, and a reduction in the Fixed Charge Rate.

Table 10: DEC's Schedule PP (NC): 10-year Capacity Rates

	Swine, Poultry, Certain Hydro		All Other Generation	
	Rate	Change	Rate	Change
Summer Months PM	1.08	-66%	0.36	-74%
Winter Months AM	10.60	-28%	3.57	-44%
Winter Months PM	0	-100%	0	-100%
Annualized	0.76	-16%	0.26	-33%

Table 11 below provides DEP's proposed 10-year levelized capacity rates (cents/kWh) during the summer and winter months and the percentage change from the approved 2020 cost rates for other QFs interconnected at the distribution level. As with DEC, avoided capacity payments have been reduced. The main drivers of the avoided capacity rate reduction in DEP are the reduction in CT costs and the reduction in the Fixed Charge Rates relative to the 2020 Proceeding.

Table 11: DEP's Schedule PP (NC): 10-year Capacity Rates				
	Swine, Poultry, Certain Hydro		All Other Generation	
	Rate	Change	Rate	Change
Summer Months PM	0	N/A	0	N/A
Winter Months AM	10.45	-28%	7.90	-15%
Winter Months PM	0	-100%	0	-100%
Annualized	0.72	-16%	0.55	0%

The Public Staff has reviewed Duke's capital cost inputs, line losses, seasonal allocations, and other assumptions incorporated in DEC's and DEP's avoided costs and finds them reasonable for the determination of their avoided capacity rates at this time. Table 12 below provides DENC's proposed capacity rates and the percent changes from 2020 approved rates for QFs interconnected at the distribution level for fixed rate 10-year contracts. The avoided capacity rates proposed by DENC are relatively unchanged from the 2020 Proceeding. The Public Staff has reviewed the capital cost inputs and other assumptions incorporated in DENC's proposed Schedule 19-FP capacity rates and finds them reasonable for the determination of DENC's avoided capacity rates at this time.

Table 12: DENC's Schedule 19-FP: 10-year Capacity Rates				
	Swine, Poultry, Certain Hydro		All Other Generation	
	Rate	Change	Rate	Change
Summer Month	7.326	-2%	3.920	-2%
Winter Month	6.775	0%	3.625	0%
Shoulder Month	1.486	-3%	0.795	-3%
Annualized	0.964	-2%	0.516	-2%

Capacity Rate Seasonal Allocation

Duke allocated the annual avoided capacity cost by season according to the loss of load risk in each hour and month, derived from the 2020 Resource Adequacy Study.[53] DEC weighted 4% of the avoided capacity cost to the summer and the rest to the winter season, with all of the winter capacity allocated to the morning hours. The distribution of LOLE for DEC in the winter and the summer is shown below; over 96% of loss of load risk is in the winter morning.

	Hour Ending																								
Season	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Sum
Winter	0.0%	0 0%	0.0%	0 3%	1 6%	6 6%	23.6%	43.3%	16.6%	4.4%	0.0%	0 0%	0.0%	0 0%	0.0%	0 0%	0.0%	0 0%	0.0%	0.0%	0.0%	0.0%	0 0%	0.0%	**96.4%**
Summer	0.0%	0 0%	0.0%	0 0%	0 0%	0 0%	0 0%	0.0%	0.0%	0.0%	0.0%	0 0%	0.0%	0 0%	0.0%	0 0%	0.0%	0 2%	1.3%	1.6%	0.5%	0.0%	0 0%	0.0%	**3.6%**

DEP used similar granularity in developing its capacity rates, allocating all of its avoided capacity costs to the winter season, with all of the winter capacity allocated to the morning hours. The seasonal allocation of the annual capacity costs is divided by the number of seasonal peak hours in order to yield the avoided capacity rates per kilowatt-hour (kWh). The distribution of LOLE for DEP in the

[53] See DEC/DEP Exhibit 8, Section IV.

winter and the summer is shown below; 99.4% of loss of load risk occurs in the winter morning.

	Hour Ending																							
Season	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**Sum**
Winter	0.2%	0.4%	1 0%	2.8%	10.1%	18.7%	27.9%	31.0%	7 0%	0.4%	0.1%	0.0%	0.0%	0 0%	0.0%	0.0%	0 0%	0.0%	0.0%	0 0%	0.1%	0.1%	0 3%	0.1%	**100.0%**
Summer	0.0%	0.0%	0 0%	0.0%	0 0%	0 0%	0 0%	0 0%	0 0%	0.0%	0 0%	0.0%	0.0%	0 0%	0.0%	0.0%	0 0%	0.0%	0.0%	0 0%	0.0%	0.0%	0 0%	0.0%	**0.0%**

For weighting capacity value between seasons, and calculating avoided capacity rates, DENC allocated CT costs consistent with the Sub 158 Order as follows: 45% summer, 40% winter, and 15% shoulder.

<u>Swine and Poultry Avoided Capacity Rates for Duke and DENC</u>

In the 2018 Proceeding, the Commission directed that the:

> "[u]tilities shall amend their Standard offer rate schedules to recognize that a swine or poultry waste-fueled generator, or a hydroelectric facility with a capacity of 5 MW or less in capacity that has a power purchase agreement in effect as of July 27, 2017, which commits to sell and deliver energy and capacity for a new fixed contract term prior to the termination of the QF's existing contract term is avoiding a future capacity need for these designated resource types beginning in the first year following the QF's existing PPA, pursuant to N.C.G.S. § 62-156(b)(3), as amended in House Bill 329.[54]

The avoided capacity credits used to calculate avoided cost rates for swine or poultry QFs begin in the first year of the standard contract, as compared to other QFs, whose capacity credits begin in the first year of a utility's capacity need. The Public Staff has reviewed these capacity credits, and other assumptions, incorporated in Duke's and DENC's proposed rates for swine and poultry QFs, and

[54] Sub 158 Order at pp 10-11.

finds them reasonable for the determination of Duke's and DENC's avoided capacity credits.

AVOIDED COST OF ENERGY

Duke's Avoided Cost of Energy

As in previous proceedings, Duke used Prosym to estimate marginal avoided energy costs over two- and 10-year periods. Prosym is an hourly chronological model that dispatches generating units in a least cost manner subject to various constraints such as scheduled maintenance of generating units, transmission import limitations, spinning reserve requirements, generation ramp rates, and minimum run times. The least cost dispatch is modeled in combination with the utility's energy sales and peak demand forecasts and the resource expansion plan from its 2020 IRP. The Public Staff has reviewed the Prosym inputs for the projected operation of Duke's generation units, including the following: variable O&M; price forecasts for delivered natural gas, coal, oil, and uranium; projected prices of SO_2 and NO_x emission allowances; projected megawatt-hour (MWh) generation from renewable energy resources; projected energy purchases; and other inputs. Based on its review, the Public Staff finds that the MW capacities, heat rates, and other inputs that characterize Duke's generation units are reasonably consistent with the 2020 Proceeding and are appropriate for this proceeding. Consistent with the Sub 158 Order, DEC and DEP included avoided fuel hedging benefits in avoided energy calculations, based on the Black-Scholes option pricing model using an estimate for gas volatility, risk-free interest rates, and a strike price, which yielded a fuel hedging value of $0.02 per MWh to supplement its avoided energy rates.

While the Public Staff believes that Duke's projection of its annual energy prices are reasonable for the short-term variable energy rate, the Public Staff has concerns with Duke's projected avoided energy costs over the entire 10 years, which is used to calculate the 10-Year Fixed energy rate, due to potential over-reliance on lower-priced shale gas, which is discussed in the Public Staff's 2020 IRP Initial Comments.[55] In its Order Accepting Integrated Resource Plans, REPS and CPRE Program Plans With Conditions and Providing Further Direction for Future Planning in Docket No. E-100, Sub 165 (2020 IRP Order), the Commission directed Duke to file a Supplemental 2020 IRP Limited DS Hub Gas portfolio no later than February 9, 2022. Duke filed the supplemental filing on February 9, 2022. Relative to Portfolio B, which had no limits on DS Hub gas access, the Limited DS Hub Gas portfolio saw 2,448 MW of natural-gas fired combined cycle generation dropped from 15-year plan. This reduction in CC capacity was replaced with 2,283 MW of CTs, 450 MW of solar and solar plus storage, and 750 MW of onshore wind. This shift in resources is projected to increase total system costs through 2050 by 5.2 billion, or 6.3%. At this time, the Public Staff does not recommend the use of the Limited DS Hub Gas portfolio as the basis for calculating avoided energy rates. However, recent developments on the status of the Mountain Valley Pipeline (MVP) cast some doubt on Duke's ability to obtain low-cost DS hub gas. The Public

[55] Public Staff's IRP Initial Comments at 89-94, filed in Docket No. E-100, Sub 165.

Staff intends to address this, and the appropriate reliance on DS hub gas in Duke's 2022 Carbon Plan, in supplemental comments in the IRP docket.

The 303-mile MVP project, designed to give North Carolina and Virginia demand markets access to the low-cost Marcellus and Utica shale gas,[56] has faced yet another setback as of January of this year.[57] This pipeline, which was scheduled to be in service by summer 2022, has lost two critical permits, likely delaying its completion for another year or more. Reliability on the constrained gas takeaway capacity from the Appalachian supply basin could affect the Appalachian gas supply prices. Further casting doubt on the MVP project's in service date, on February 19, 2021 it was reported that NextEra Energy stated in a filing with the Securities and Exchange Commission that "it was determined that the continued legal and regulatory challenges have resulted in a very low probability of pipeline completion."[58] If the MVP is not completed, the MVP Southgate project, which would carry DS hub gas from Virginia into North Carolina, will almost certainly not be completed.

Figure 2 displays annualized avoided energy costs projected by DEC & DEP. **[BEGIN CONFIDENTIAL]** [redacted]

[56] MVP would carry gas into Virginia; the companion MVP Southgate project would carry gas from Virginia into North Carolina.

[57] https://www.eenews.net/articles/court-deals-major-blow-to-mountain-valley-pipeline/

[58] NextEra Energy Form 10-K for the fiscal year ended December 31, 2021. Filed with the SEC on February 18, 2021 at 90.

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

Duke's proposed variable and 10-year levelized energy rates (cents per kWh) for QFs interconnected at the distribution level, along with the proposed annualized rates (cents per kWh) with the percentage change from the approved rates in the 2020 Proceeding, are shown in Tables 13 and 14 below. The variable rates show much larger increases than the 10-year rate, primarily due to lower long-term natural gas forecasts used in years three through eight. The variable rates are heavily influenced by the near-term spike in natural gas prices that is reflected in Duke's forward market price forecasts.

Table 13: DEC's Schedule PP (NC): Energy Credits				
	Variable		10-year	
	Rate	Change	Rate	Change
Summer Premium Peak	4.23	24%	3.94	18%
Summer PM Peak	4.04	42%	3.87	24%
Summer Off-Peak	3.60	33%	3.40	20%
Winter Premium Peak	6.31	69%	5.76	40%
Winter AM Peak	5.37	78%	4.73	29%
Winter PM Peak	5.26	81%	4.50	32%
Winter Off-Peak	4.54	74%	3.81	31%
Shoulder Peak	4.37	46%	3.77	24%
Shoulder Off-Peak	3.02	30%	2.71	18%
Annualized	**3.89**	**45%**	**3.73**	**17%**

Table 14: DEP's Schedule PP (NC): Energy Credits				
	Variable		10-year	
	Rate	Change	Rate	Change
Summer Premium Peak	4.36	30%	3.97	23%
Summer PM Peak	3.96	38%	3.64	23%
Summer Off Peak	3.51	36%	3.35	20%
Winter Premium Peak	6.93	73%	5.96	36%
Winter AM Peak	4.93	68%	4.47	35%
Winter PM Peak	5.36	61%	4.91	33%
Winter Off Peak	4.47	65%	3.99	33%
Shoulder Peak	4.22	51%	3.73	27%
Shoulder Off Peak	3.25	43%	2.88	23%
Annualized	**3.91**	**48%**	**4.09**	**22%**

Solar Integration Services Charge (SISC)

In this proceeding, DEC proposes a SISC of $1.05 per MWh and DEP proposes a SISC of $2.26 per MWh.[59] These proposed figures represent a 5% decrease from the SISCs approved in the Sub 158 and Sub 167 proceedings. These charges were calculated based upon 2,431 MW of solar in DEC and 4,019 MW of solar in DEP, which is slightly more than the amount of solar expected to be interconnected by 2024 (the study year). As discussed in the Sub 158 Issues section of these comments, the reduction in the SISC is largely driven by methodology changes. The ability to share load following reserves benefits both DEC and DEP; for example, if the island[60] results were used, DEC's SISC would have increased by 30% relative to the Sub 167 SISC, and DEP's would have increased by 1%. The Public Staff finds that Duke satisfied the requirements of the Sub 158 Order during the TRC process, and recommends that DEC's and DEP's proposed SISCs be approved and the TRC Report be accepted.

In the Sub 158 Proceeding, Duke filed proposed Requirements for Avoidance of SISC. These requirements were approved by the Commission in its August 17, 2021 Order Approving SISC Avoidance Requirements and Addressing Solar-Plus-Storage Qualifying Facility Installations (SISC Avoidance Order). While neither DEC nor DEP filed this approved procedure in this docket, the SISC avoidance criteria are referenced, but not explicitly provided, in their proposed Schedule PP tariffs.[61] The Public Staff requests that Duke confirm, in its reply

[59] These decrements are reflected in the above tables.
[60] The island scenario does not allow reserve sharing between DEC and DEP.
[61] *See* Duke Joint Initial Statement, Exhibit 1, Schedule PP, footnote 3.

comments, that the SISC avoidance criteria referenced in the proposed tariffs reflect the use of the approved SISC avoidance methodology, and that Duke consider including the full SISC avoidance requirements in its Schedule PP tariffs, similar to how DENC documents its re-dispatch avoidance protocol.

In the interest of transparency around SISC avoidance, the Public Staff also recommends that the Commission direct Duke to file a report on QFs that attempt to avoid the SISC, and include an analysis of actual solar volatility reductions of QFs that avoid the SISC in Duke's service territories in future avoided cost filings. In addition, the Public Staff recommends the Commission direct Duke to specifically address QFs seeking SISC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of SISC credits issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the SISC.

DEC and DEP Treatment of Start Costs

In the 2020 Proceeding, the Public Staff identified issues with how start and stop costs were represented in the production cost model, which led to counterintuitive rate designs such as a winter AM-peak rate that was lower than the winter off-peak rate. The Public Staff found that Duke had modified its modeling to represent start costs as a lump sum, rather than allocated to all hours a unit was running. The issue was rectified, and the Public Staff continued to work with Duke on this matter, pursuant to the Sub 167 Order.[62] In this proceeding, Duke has

[62] Sub 167 Order, at 40.

continued to model start costs as it has historically, spreading start costs over all hours that the individual unit operates. The Public Staff finds this approach reasonable for this proceeding because it has produced rates that generally align with the purpose of the Rate Design Stipulation approved in the Sub 158 Proceeding.

DENC's Avoided Cost of Energy

DENC's Schedule 19-FP Energy Rates

DENC's method for calculating avoided energy costs for Schedule 19-FP is largely consistent with methods employed in the 2020 Proceeding, using the PLEXOS production cost model.

The least cost dispatch is modeled in combination with DENC's energy sales and peak demand forecasts using its generation expansion plan "B" included in its 2021 IRP Update. Similar to Duke, DENC incorporated a "without QF" case and a "with QF" case, and used the difference in output costs to calculate the avoided energy rates. The Public Staff has reviewed the PLEXOS inputs and believes that the inputs into the model and the output data from the model are reasonable for the determination of DENC's avoided energy costs.

Consistent with the Sub 158 proceeding, DENC included avoided fuel hedging values in its avoided energy calculations based on the Black-Scholes option pricing model, using an estimate for gas price volatility, a risk free interest rate, and the strike price, which yielded a net option price of $0.0022 per MMBtu. The hedging benefit was multiplied by the 7.0 MMBtu/MWh heat rate of a natural gas combined cycle unit to yield a hedging value of $0.02/MWh to supplement DENC's avoided energy costs.

DENC's proposed variable and 10-year levelized energy rates (cents per kWh) for intermittent QFs subject to the re-dispatch charge, interconnected at the distribution and transmission level, along with the percentage change from the approved rates in the 2020 Proceeding, are shown in Table 15 below.

Table 15: DENC's Schedule 19-FP: Energy Credits				
	Variable		10-year	
	Rate	Change	Rate	Change
Summer – Premium Peak	4.28	13%	3.76	-13%
Summer – On Peak	3.15	7%	2.75	-17%
Summer – Off Peak	2.15	8%	2.10	-8%
Winter – Premium Peak	5.08	24%	3.85	-3%
Winter – On Peak (AM)	4.35	27%	3.22	-4%
Winter – On Peak (PM)	4.35	25%	3.21	-5%
Winter – Off Peak	3.34	21%	2.61	-8%
Shoulder On-Peak	2.92	5%	2.18	-20%
Shoulder Off-Peak	2.07	3%	1.81	-14%
Annualized	**3.02**	**15%**	**3.06**	**-7%**

Figure 3 displays annualized avoided energy costs projected by DENC. The avoided energy rates are lower in later years, and do not exhibit a significant increase in later years. DENC estimates that overall, the addition of new low-variable cost resources such as solar, wind, and battery storage contribute to a cumulative 7% reduction in avoided energy rates; in 2031, DENC estimates that avoided energy rates will be 16% lower as a result of the resources selected by its VCEA-compliant expansion plan.

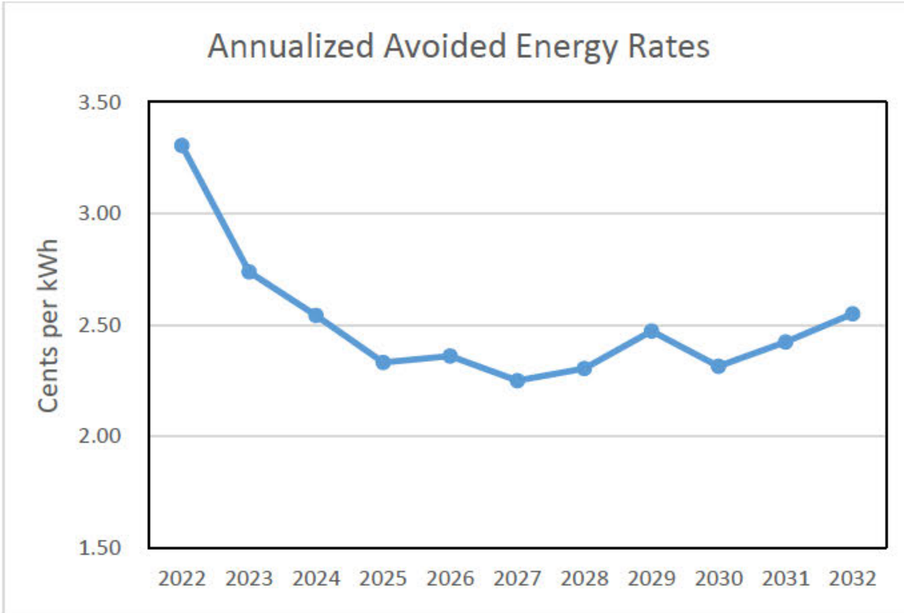

Figure 3: DENC's Annualized Avoided Energy Costs

<u>DENC's Schedule 19-LMP Energy Rates</u>

The proposed Schedule 19-LMP energy is based on the hourly PJM Day Ahead LMPs at the nearest PJM-defined nodal location to the QF. To derive the cents per kWh price, the dollars per MWh PJM Dominion Zone Day-Ahead hourly LMPs are divided by 10 and then multiplied by the QF's hourly net generation.

<u>DENC's Re-Dispatch Charge (RDC)</u>

DENC continues to apply the RDC that was originally approved in the Sub 158 Order. The RDC proposed in this filing is based upon an updated methodology proposed in DENC's 2021 IRP Update. Based upon the updated calculation, DENC estimates that the RDC associated with intermittent solar and wind generation is 0.187 cents per kWh. This RDC is reflected in the above tables. The Public Staff has reviewed the revised methodology and generally finds it to be an improvement over the methodology approved in the Sub 158 Proceeding and used in the Sub 167 Proceeding. The prior methodology focused only on a single year, running multiple PROMOD runs with varying solar output profiles at specific generation sites, to calculate the RDC. The new model uses Alternative Plan D from DENC's 2020 IRP to calculate the RDC in each future year by calculating the cost difference between "day ahead" and "real time" model runs, creating a RDC cost curve using the Aurora model. The Aurora software used by DENC models the entire Eastern Interconnection, endogenously calculating the market prices for energy in PJM and the appropriate level and optimal sources of ancillary services.

In addition, the Commission approved DENC's proposed protocol for avoidance of the RDC.[63] The approved protocol allows a QF to reduce the RDC "to the extent the QF reduces the variability of its output through the use of an energy storage device (ESD)."[64] This approved RDC avoidance protocol is included in this filing, and the Public Staff finds the protocol reasonable for this proceeding. The Public Staff notes that as of the filing of DENC's Initial Statement, no QFs in DENC's territory are currently avoiding the RDC. The RDC avoidance protocol is specifically described in Section IV of DENC's schedule 19-FP tariff. The RDC is not assessed on facilities selling power under the schedule 19-LMP tariff.

In the interest of transparency around SISC avoidance, the Public Staff recommends that the Commission direct DENC to file a report on the types of forecasts and the ESD dispatch behavior for QFs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of QFs

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[63] Sub 167 Order, at 48.
[64] DENC Initial Statement, at 15.

in DENC's service territory in its future avoided cost filings. In addition, the Public Staff recommends the Commission direct DENC to specifically address QFs seeking RDC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of RDC credit issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the RDC.

WCU AND NEW RIVER AVOIDED COST RATES

On December 16, 2021, WCU and NRLP filed a motion for extension of time to file their avoided cost rates. On December 20, 2021, the Commission granted the request. On December 21, 2021, WCU and NRLP filed their avoided cost rate proposals.

In their initial statements, WCU and NRLP note that effective January 1, 2022, both companies will begin taking power supplies from Carolina Power Partners (CPP) instead of DEC. WCU and NRLP expect to update their avoided cost rates later in 2022 upon a completion of a cost-of-service study. WCU and NRLP proposed to offer variable rates based upon their wholesale cost of power that reflect the wholesale rates paid to CPP. WCU and NRLP propose three formulas to calculate the avoided cost rates for: 1) small power producers or cogenerators that desire to receive the demand credit (Rate SPP Demand); 2) aggregate customer loads where the customer foregoes the demand credit (Rate SPP No Demand); and 3) customer loads where the provider desires a long-term avoided cost rate (SPP-Fixed).

WCU and NRLP propose to delete their $25 administrative charge for facilities that are willing to forego a demand credit. WCU and NRLP also noted that neither utility offers net metering, and both have limited QFs operating on their systems.

The Public Staff does not object to WCU's and NRLP's proposed rates for purposes of the 2021 proceeding.

MODIFICATIONS TO TERMS AND CONDITIONS

FERC ORDER NO. 872 AND THE COMPANIES' REVISIONS TO THEIR NOTICE OF COMMITMENT AND LEO FORMS

The Commission required the submittal of a standardized Notice of Commitment form (NOC) to establish a legally enforceable obligation (LEO) in its Sub 140 Order.[65] One of the requirements to receive a LEO is the receipt of a Certificate of Public Convenience and Necessity (CPCN) from the Commission. The Commission ordered revisions to the NOC in the last several avoided cost proceedings but none affected the requirement of a CPCN to obtain a LEO.

FERC issued Order No. 872 on July 16, 2020.[66] This order updated FERC regulations implementing PURPA. In regard to establishing a LEO, FERC required that QFs "demonstrate that a proposed project is commercially viable and that the QF has a financial commitment to construct the proposed project, pursuant to objective, reasonable, state-determined criteria in order to be eligible for a LEO."[67]

[65] Sub 140 Order at 51.
[66] FERC Order No. 872.
[67] FERC Order No. 872 at ¶ 684.

FERC found that a showing of commercial viability and financial commitment would ensure that QF projects that are not sufficiently advanced in their development would be included in the utility's resource planning.[68] Order No. 872 explained that any factors that a state requires a QF to demonstrate in order to receive a LEO "must be within the control of the QF."[69] Examples of such a showing are "(1) taking meaningful steps to obtain site control adequate to commence construction of the project at the proposed location; and (2) filing an interconnection application with the appropriate entity."[70]

Order No. 872 also adopted a new rule governing when affiliated QFs are considered to be located at the same site, and therefore considered a single facility for purposes of the 80 MW small power producer limitation. The rule states that (1) there is an irrebuttable presumption that affiliated small power producer (SPP) QFs that use the same energy resource and are located one mile or less from each other are located at the same site; (2) there is also an irrebuttable presumption that affiliated SPP QFs that use the same energy resource and are located 10 miles or more apart are located at separate sites; and (3) there is a rebuttable presumption that affiliated SPP QFs that use the same energy resource are located more than one mile and less than 10 miles from each other are located at separate sites.[71]

[68] *Id*.
[69] *Id*. at ¶ 685.
[70] *Id*.
[71] *Id.* at ¶ 872.

Duke proposes to update DEP's and DEC's respective NOCs to accomplish three primary objectives: (1) incorporate the new commercial viability and financial commitment requirements established in Order No. 872; (2) align the NOC with the now-approved queue reform process under the North Carolina Interconnection Procedures; and (3) update the non-standard offer NOC to establish a more standardized and efficient process for QFs to proceed from NOC to PPA.[72] Attachment C to Duke's NOC 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 System Impact Study (DISIS) 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) has provided reasonable evidence and documentation of the QF's commitment to develop the project by including 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.[73] Duke also modified the NOC to align with its Queue Reform, which replaced the serial interconnection queue study process with the DISIS process. The DISIS process is a multi-step cluster study process under NCIP Section 4.4, which was established to help move projects through the interconnection queue more quickly in part by reducing the number of speculative projects entering the interconnection process through

[72] Duke Joint Initial Statement at 49.
[73] *Id*. at 51-52.

increased study deposits, commercial readiness requirements, and financial commitments for non-ready projects as they progress through the interconnection study process. These concepts established in the DISIS process generally align with the new commercial viability requirements to establish a LEO under PURPA. Lastly, Duke stated that it was proposing the update to the NOC to provide a more standardized and streamlined process for QFs to progress from a NOC to a mutually binding PPA. Duke believes that the revised NOC does this by requiring, in Section 3 and Attachment B of the Large QF NOC, QFs to provide all information that Duke will need to develop an executable form of PPA that the QF could then sign in a reasonable time.[74]

DENC, in its Initial Statement, proposes to revise its LEO Forms to include confirmation that the QF is not less than one mile, or between one and 10 miles, of an affiliated facility using the same energy resource. If the QF is located between one and 10 miles of an affiliated facility using the same energy resource, the revised LEO Forms allow the QF to provide more detailed confirmations to rebut the presumption that it is located at the same site as the affiliated project.[75] DENC also proposes to modify its LEO Forms to include a statement by the QF to demonstrate commercial viability and financial commitment, stating that the QF has taken meaningful steps to obtain site control adequate to commence construction of the project at the proposed location; and submitted all required applications including filing fees to obtain all necessary local permitting and zoning

[74] *Id.* at 53
[75] DENC Initial Statement at 30.

approvals. DENC believes that that these modifications in combination with the existing requirement that the QF must have submitted an Interconnection Request and reached certain milestones in the interconnection process will ensure that the QF will have sufficiently demonstrated its commercial viability and financial commitment to justify obtaining a LEO.

The Public Staff generally supports the revisions to Duke's NOCs and DENC's LEO Forms. The Public Staff agrees with Duke that the revisions incorporate the new commercial viability and financial commitment requirements established in Order No. 872, align the LEO process with the new DISIS process, and establish a more standardized and efficient process for QFs to proceed from the NOC to a PPA. The Public Staff believes that Duke needs assurances that projects entering into the DISIS study process are commercially viable and progressing toward construction and the sale of the project's output to the utility in order to rely on those projects in its planning process. Further, the NOC is designed to provide a more efficient path for QFs to commit themselves to deliver capacity by executing a PPA and imposing a hard deadline for the QFs to do so after receiving a Facilities Study Agreement. Obtaining a LEO also allows a QF to show readiness in the DISIS process, allowing the QF to submit a smaller financial commitment to enter and continue through the early stages of the DISIS process.

The Public Staff also believes that the modifications to DENC's LEO Forms is consistent with Order No. 872 by ensuring commercial and financial viability and requiring the QFs to provide enough information for DENC to determine whether the QF is located at a separate site from an affiliate facility.

The Public Staff therefore recommends that the Commission approve the revisions to Duke's NOCs. The Public Staff also believes that DENC's revisions to its LEO Forms meet the requirements FERC set out in Order No. 872 and should be approved by the Commission.

ENERGY STORAGE RETROFIT

In its filing, Duke provided New Energy Storage System (ESS) avoided cost rates for QFs that retrofit their facilities with energy storage. As proposed, these rates would be made available to QFs that: i) are currently selling power to DEC or DEP, and ii) established a LEO or entered into a PPA prior to November 15, 2016, and wish to retrofit their facilities with energy storage. The process for studying these facilities, along with eligibility for the New ESS Retrofit avoided cost rates, is contained in the ESS Retrofit procedure outlined in Duke's September 29, 2021 Compliance Filing in Docket No. E-100, Subs 101 and 158, as modified by Duke's November 5, 2021 Reply Comments (ESS Compliance Filing).

Duke has used forecast data beginning on January 1, 2023, to calculate the 2, 3, 4, 5, 6, 7, 8, 9, and 10-year New ESS Retrofit avoided cost rates, reflecting the reality that QFs retrofitting their facilities with energy storage will proceed through the Definitive Interconnection System Impact Study (DISIS), and pursuant to DISIS timelines, will not be online until 2023 at the earliest.[76]

[76] *See* Duke's September 29, 2021 Compliance Filing, Attachment C at 2.

The Public Staff finds the proposed rates and eligibility requirements to be generally reasonable, subject to the concerns laid out in the Public Staff's October 21, 2021 Comments on Duke's ESS Retrofit Compliance Filing.[77] In the Public Staff's Sub 158 Initial Comments, however, it recognized the conflict between incentivizing energy storage while not overcompensating QFs at "stale rates" for output from the energy storage system. The Public Staff's bifurcated rate proposal would "balance the need to incentivize new technologies with establishing appropriate rates" by "separately [metering] any additional energy output from the original facility and compensate the additional output at the then-current Commission approved avoided cost rates without requiring the existing facility to forfeit payments under the terms of its pre-existing PPA."[78] In its Sub 158 Order, the Commission found it was "premature at this time to decide whether the compromise position is appropriate."[79]

The Public Staff observes that three separate items must be approved by the Commission in order to finally resolve the ESS retrofit process, rates, and eligibility. First, Duke's ESS Compliance Filing must be approved. Next, the New ESS Retrofit avoided cost rates filed in this docket must be approved. Finally, the Public Staff's bifurcated rate proposal must be approved. Therefore, the Public Staff recommends that in this proceeding, the Commission approve both Duke's proposed New ESS Retrofit avoided cost rates and the Public Staff's bifurcated rate proposal. In the event that the Commission, in its final order in this proceeding,

[77] Filed in Docket Nos. E-100, Sub 101 and E-100, Sub 158.
[78] Sub 158, Initial Comments of the Public Staff at 75.
[79] Sub 158 Order at 131.

directs Duke to recalculate its avoided cost rates based upon the Public Staff or intervenor comments, Duke should also provide updated New ESS Retrofit avoided cost rates, recalculated pursuant to the Commission's directives.

The Public Staff notes that on January 25, 2022, the Commission issued its Order Establishing Proceeding and Requesting Comments in Docket No. E-100, Sub 181. This proceeding will investigate modifications to certain existing PPAs with eligible small power producers, pursuant to section 6 of HB 951 (Blend and Extend). The Public Staff will address the applicability of the ESS Retrofit process and avoided energy rates to Blend and Extend facilities in that docket.

CONCLUSIONS AND RECOMMENDATIONS

In summary, the Public Staff recommends that the Commission:

(1) approve Duke's avoided energy and capacity rates using Portfolio A without a carbon price at this time, subject to other the other recommendations below;

(2) approve DENC's avoided energy and capacity rates;

(3) direct Duke to make a supplemental filing providing a re-calculated annualized NEEC rate for use in the NEM Tariffs that is i) weighted to a solar profile, ii) differentiated by season, and iii) based on a 5-year avoided cost rates, and that future avoided cost filings include an explicitly calculated NEEC for use in Duke's NEM Tariffs;

(4) direct Duke, in its next avoided cost filing, to use the approved

Carbon Plan as the expansion portfolio and include the Commission-approved avoidable cost of carbon, if any, determined in the Carbon Plan proceeding in its calculation of avoided energy and capacity rates;

(5) direct Duke and DENC to address the inclusion of solar and wind generator outage data in the calculation of the PAF in their next avoided cost filings, including the current status of outage reporting requirements set by NERC;

(6) direct Duke to consider the effect of the SEEM on the calculation of the SISC in any avoided cost filings that occur six months or more after SEEM operations commence;

(7) direct Duke to file a report on QFs that attempt to avoid the SISC and include an analysis of actual solar volatility reductions of QFs that avoid the SISC in Duke's service territories in its future avoided cost filings;

(8) direct Duke to specifically address QFs seeking SISC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of SISC credit issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the SISC;

(9) approve DEC's and DEP's proposed SISC and the TRC Report be accepted;

(10) direct DENC to file a report on the types of forecasts and the ESD dispatch behavior for QFs that attempt to avoid the RDC and include this information, as well as an analysis of actual solar volatility of QFs in DENC's

service territory in its future avoided cost filings;

(11) direct DENC to specifically address QFs seeking RDC avoidance in direct testimony filed in future fuel rider proceedings, providing the specific facilities and amount of RDC credit issued, supporting workpapers, and reports on any audits performed on QFs seeking to avoid the RDC;

(12) approve both Duke's proposed revisions to its NOC and DENC's proposed revisions to its LEO Forms; and

(13) approve both Duke's proposed New ESS Retrofit avoided cost rates and the Public Staff's bifurcated rate proposal.

WHEREFORE, the Public Staff respectfully requests that the Commission take the foregoing comments and recommendations into consideration.

Respectfully submitted this the 24th day of February, 2022.

PUBLIC STAFF
Christopher J. Ayers
Executive Director

Dianna W. Downey
Chief Counsel

Electronically submitted
Robert B. Josey
Staff Attorney

4326 Mail Service Center
Raleigh, North Carolina 27699-4300
Telephone: (919) 733-6110

CERTIFICATE OF SERVICE

I certify that a copy of these Comments has been served on all parties of record or their attorneys, or both, by United States mail, first class or better; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 24th day of February, 2022.

Electronically submitted
/s/ Robert B. Josey