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November 17, 2021

VIA ELECTRONIC FILING
The Honorable Jocelyn G. Boyd
Chief Clerk/Executive Director
Public Service Commission of South Carolina
101 Executive Center Drive, Suite 100
Columbia, SC 29210

Re: South Carolina Energy Freedom Act (H.3659) Proceeding Initiated Pursuant to S.C. Code Ann. Section 58-40-20(C): Generic Docket to (1) Investigate and Determine the Costs and Benefits of the Current Net Energy Metering Program and (2) Establish a Methodology for Calculating the Value of the Energy Produced by Customer-Generators
Docket Number: 2019-182-E

Response to Commission Order No. 2021-569

Dear Ms. Boyd:

On August 19, 2021, the Public Service Commission of South Carolina (the "Commission") issued Order No. 2021-569 in the above-referenced docket. I am filing this letter on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC in response to certain actions required by the Commission's Order to be undertaken with ninety (90) days.

Kind regards,

Sam Wellborn

cc: Parties of record (via electronic mail)

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South Carolina Energy Freedom Act (H.3659) Proceeding Initiated Pursuant to S.C. Code Ann. Section 58-40-20(C): Generic Docket to (1) Investigate and Determine the Costs and Benefits of the Current Net Energy Metering Program and (2) Establish a Methodology for Calculating the Value of the Energy Produced by Customer-Generators
Docket No. 2019-182-E

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC RESPONSE TO COMMISSION ORDER NO. 2021-569

I. INTRODUCTION

On August 19, 2021, the Public Service Commission of South Carolina (the "Commission") released an order in Docket No. 2019-182-E related to how costs and benefits should be determined for Net Energy Metering ("NEM") programs. Commission Order No. 2021-569 (the "Order") instructed the Companies to take certain actions within ninety (90) days of the issuance of the Order. Through this filing, Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC the "Companies") are providing the Commission with an update on the status of their compliance with the Commission's instructions.

Specifically, the Companies are responding to the below requirements from the Order:

1. Provide the Commission a narrative of how the Companies plan to improve data capabilities over time to improve the insight into the transmission and distribution systems and to modernize the planning of transmission and distribution assets to take into account the ability of DERs to avoid or defer traditional, utility-owned T&D capital investments. Order 2021-569, Page 44.
2. Develop a plan to acquire the capability to determine the marginal line losses associated with customer-generator facilities. Order 2021-569, Page 46.
3. Investigate the feasibility of developing programs and capabilities to leverage ancillary service capabilities from customer-generators consistent with industry best practices (e.g., IEEE standards for DER and distributed generation). Order 2021-569, Page 39. Evaluate the creation of programs to leverage DER to provide ancillary services especially as technology development leads to storage. Order 2021-569, Page 53.

II. REQUIREMENT TO PROVIDE A NARRATIVE RELATED TO IMPROVING DATA CAPABILITIES TO IMPROVE INSIGHT INTO T&D SYSTEMS

At the outset, the Companies note that there are a number of findings and requirements in the Order that factor into the Companies' response. Those findings and requirements are summarized below.

A. Commission Findings:

- Avoided transmission and distribution may have a non-zero value.[1]

[1] Order No. 2021-569, Page 44. "The Commission finds that avoided transmission and distribution may have a non

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- Electrical utilities should make greater effort to quantify avoided transmission and distribution value using a methodology that accounts for relative availability and granularity of data about the distribution and transmission system.[2]

- While transmission and distribution costs are location-specific, it would take some analytical sophistication and a more transparent transmission and distribution ("T&D") planning process to assign values with that level of precision and granularity in time and location. Accordingly, it is reasonable to provide electrical utilities flexibility at this time to employ a methodology that reflects the current state of available data.[3]

B. <u>Commission Requirements:</u>

- Value of distributed energy generation shall include a methodology to quantify long-run impacts of aggregate customer generators on avoided transmission and distribution costs.[4]

- Describe plans to improve data capabilities over time to improve insight into the transmission and distribution systems.[5]

- Describe plans to modernize the planning of transmission and distribution assets to take into account the ability of Distributed Energy Resources ("DER") to avoid or defer traditional, utility-owned T&D capital investments.[6]

- Collect data with sufficient granularity to provide the Commission with quantitative analysis of avoided transmission and distribution costs.[7]

C. <u>Response</u>

The Companies' response to this portion of the Order is broken down into three key topics:

1) Traditional Grid Planning Construct

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zero value and electrical utilities should make greater effort to quantify a value using a methodology that accounts for relative availability of and granularity of data about the distribution and transmission system. While transmission and distribution costs are location specific, the Commission acknowledges that it would take some analytical sophistication and a more transparent T&D planning process to assign values with that level of precision and granularity in time and location. Accordingly, it is reasonable to provide electrical utilities flexibility at this time to employ a methodology that reflects the current state of available data."

[2] *Id.*

[3] *Id.*

[4] Order No. 2021-569, Pages 52-53. "With regard to the value of distributed energy generation under Act 62 methodology approved in Commission Order No. 2015-194, the value stack shall be retained with the following modifications: E. Inclusion of a methodology to quantify long-run impacts of aggregate customer generators on avoided transmission and distribution costs. Thus, the electrical utilities shall collect data with sufficient granularity to provide the Commission with quantitative analysis of avoided transmission and distribution costs."

[5] Order No. 2021-569, Page 44. "Electrical utilities, however, are directed to provide the Commission, within 90 days of this order, a narrative of how they plan to improve these data capabilities over time to improve the insight into the transmission and distribution systems and to modernize the planning of transmission and distribution assets to take into account the ability of DERs to avoid or defer traditional, utility-owned T&D capital investments."

[6] *Id.*

[7] *See supra* note 4.

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2) New Tools and Processes Required for Grid Modernization Planning
3) Planning Data and Data Management Systems

1) Traditional Grid Planning Construct

Capacity needs for individual grid assets may be driven by summer peak or winter peak demands, depending on the local conditions, which can change through time due to economic development, DER adoption, and other factors. Net metered solar has historically been allowed to interconnect without restriction or site-specific study based on the Companies' experience that they can generally be accommodated within the existing utility system and have not typically precipitated a need for system upgrades. Furthermore, because NEM resources have varying configurations, are not maintained by the Companies, and operate intermittently, localized capacity value at the time of circuit peak loading can be difficult to estimate with precision. The Companies expect to better understand the localized capacity value of NEM resources within the grid planning construct as system modeling becomes more sophisticated.

2) New Tools and Processes Required to Support Grid Planning Modernization

Several regional and utility specific factors can influence the need for modernizing grid planning. Growth of utility scale DERs, availability of advanced technologies to improve resilience and reliability while enabling non-demand side activity DERs, changing customer use patterns, and support from regulators are among the most impactful factors for the timing and pace of modernizing grid planning tools and processes. In regions where these factors converge, power flow models and accompanying circuit load forecasts for grid planning are evolving from seasonal peak analyses to hourly granularity with time-series power flow modeling capability. These tools and processes will allow planners to begin to assess circuit performance for every hour of the year, with capability to factor in non-coincident elements of customer load, load shaping customer programs and variable energy resources. Grid planners will also need tools to examine circuit performance over a longer time horizon to assess the impact of the new load flow profiles and distributed resources to assure reliable power delivery over a range of potential future conditions. The Companies recognized about five years ago that these factors were taking shape in their jurisdictions and concluded that it would be appropriate to form a cross-functional initiative to prepare for modernizing grid planning. This effort culminated in the Companies' Integrated System and Operations Planning ("ISOP") initiative. The primary components of ISOP related to this Order are the Advanced Distribution Planning toolset and processes and the ten-year hourly time series circuit level forecasting toolset referred to as Morecast.

Planners will be able to use the new hourly circuit level forecasts and power flow models to study *net loads* on the circuits which include the variable resources and also examine *gross loads* with the variable resources removed to better ascertain reliability margins needed for the local system across a range of operating conditions. These new tools will be helpful to grid planners for examining the localized impacts of these new resources more closely as adoption grows over time. There will also be new tools that will make it easier to look back at historical loading to see how past performance may have been impacted.

The Companies deployed the first production version of these new circuit level forecasts and planning models in September of 2021. It will take time to implement and refine these new

planning systems and for planners to become familiar with the new features, methods, and applications.

3) Planning Data and Data Management Systems

As noted above, the Companies' T&D systems are experiencing increasing levels of DERs and more complex grid management systems (e.g. Distribution Management System, DER Management System, and Self-Optimizing Grid) that necessitate modernization of grid forecasting, planning tools, and data systems. Grid data management and data quality initiatives have become cornerstone efforts within the Companies' planning modernization efforts that are occurring as the new ISOP functions are being established.

Data that has traditionally been used for system planning, including grid configuration and circuit and bank loading is now being used in different ways. To enable integration across the major planning tools, refinement and additional new system data are needed to reflect:

- Physical and network interconnection location, characteristics and operations of DERs including customer and utility solar and storage resources, and
- Evolving customer energy requirements looking ahead to electrification of transportation, building systems and industrial processes with associated advanced controls, and potential new EE/DSM programs and rate structures.

As grid planning and forecasting models evolve, the new data management systems will evolve to:

- Help organize and structure the data in a manner that supports the new models and tools,
- Provide grid planners more visibility and more efficient access to a wide array of system data that is needed, and
- Provide flexibility and upgradability as new programs, systems, and data (e.g., AMI history, EVs, NEM) become available.

III. REQUIREMENT TO DEVELOP A PLAN TO ACQUIRE MARGINAL LINE LOSS DATA

Commission Order No. 2021-569 required the Companies to develop a plan to acquire marginal line loss data to determine the marginal line losses associated with customer-generator facilities. Other instructions within the Order also impact this requirement and are summarized below.

A. Commission Findings:

- Calculate avoided line losses on a marginal basis considering only daylight hours.[8]

[8] Order No. 2021-569, Page 13. "The best practice is to calculate avoided line losses on a marginal basis considering only daylight hours (when solar PV produces)." Order No. 2021-569, Page 52. "8. With regard to the value of distributed energy generation under Act 62 methodology approved in Commission Order No. 2015-194, the value

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B. Commission Requirements:

- Develop a plan to acquire the capability to determine marginal line losses associated with customer-generator facilities.[9]

C. Response:

The Companies' response to this portion of the Order is broken down into two key topics:

1) Average Line Losses
2) Marginal Line Losses – Daylight Hours

1) Average Line Losses

The Companies currently quantify the total peak and annual line losses to support a variety of studies and regulatory filings. The methods employed have been developed over time and reflect substantial review and input from regulators and other stakeholders. This line loss analysis addresses all the transmission and distribution elements from the generator to the customer meter which includes losses due to generator step-up transformers, transmission lines, substation transformers, distribution primary lines, secondary transformers, secondary conductors, and service conductors. However, all these elements are not contained in a single planning model so a variety of tools and methodologies have been implemented to calculate these losses based on the data available.

The historic use of a combination of representative hours and circuits for calculating average line losses is consistent with industry best practices and the Companies are utilizing hourly load data, DER generation profiles and study automation as it becomes available. The Companies have confidence in their average line loss results based on their ability to benchmark against many historical studies and industry peers and are not proposing any major changes to the base methodology.

2) Marginal Line Losses – Daylight Hours

In response to the request for "avoided line losses [to] be calculated on a marginal basis considering daylight hours only," the Companies propose to add to their existing average loss methodologies to calculate marginal losses.

- For transmission, loss curves are developed to extrapolate from the representative hours to estimate every hour of the year. For each daylight hour of the year, the marginal line loss will be derived from these curves.

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stack shall be retained with the following modifications: B. That avoided line losses be calculated on a marginal basis considering daylight hours only."

[9] Order 2021-569, Page 46. "The Commission modifies the existing methodology to require that electrical utilities determine the marginal line losses associated with customer-generator facilities. If marginal line loss data does not exist for an electrical utility, the Commission directs the development of a plan within 90-days of this Order to acquire this capability."

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- The distribution primary marginal losses will be calculated by comparing the losses from a power flow case with net metering solar turned on versus a case with net metering solar turned off. This methodology will evaluate the impact of a solar production profile that aligns with the total solar capacity on that representative circuit, which will capture the marginal loss impact during daylight hours since solar only generates during daylight hours.

- The losses for transformers, secondary and service conductors that are not modeled in power flow tools will be calculated utilizing databases of historical loads and impedances. A marginal loss percentage will be calculated by making a small change in the net load during daylight hours and measuring the impact on losses.

- Based on availability and quality of solar locational data, the substation and distribution results will be weighted by the amount of existing NEM capacity interconnected at each substation or feeder.

D. Summary:

The Companies plan to implement this proposed methodology while updating the average line loss study in 2022. However, because of the complexity of this additional analysis, the Companies may elect to continue to use average line losses for some or all elements of the line losses in the value stack for distributed energy resource generation until the accuracy of the new marginal line loss modeling methodology and its results can be validated through repeated analysis. In addition, the proposed methodology is based on the data and tools that are expected to be available but may need to be modified when the analysis is performed.

IV. REQUIREMENT TO INVESTIGATE FEASIBILITY OF PROGRAMS TO LEVERAGE ANCILLARY SERVICE CAPABILITIES

Commission Order No. 2021-569 required the Companies to investigate the feasibility of developing programs and capabilities to leverage ancillary service capabilities from customer-generators consistent with industry best practices.

A. Commission Requirements:

- Investigate the feasibility of developing programs and capabilities to leverage ancillary service capabilities from customer-generators consistent with industry best practices.[10]
- Evaluate the creation of programs to leverage DER to provide ancillary services especially as technology development leads to storage.[11]

[10] Order 2021-569, Page 39. "The Commission requires the electrical utilities to investigate the feasibility of developing programs and capabilities to leverage ancillary service capabilities from customer-generators consistent with industry best practices (e.g., IEEE standards for DER and distributed generation)."

[11] Order 2021-569, Page 53. "Customer generators are not currently utilized to provide ancillary services. Therefore, electric utilities are hereby required to evaluate the creation of programs to leverage DER to provide ancillary services especially as technology development leads to storage."

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B. Response:

In Order 2021-569, the Commission required the electrical utilities to investigate the feasibility of developing programs and capabilities to leverage ancillary service capabilities from customer-generators consistent with industry best practices. Ancillary services are defined as those services necessary to support reliable operation of the utility system's balancing authority and to support transmission of electric power from sellers to purchasers, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system; including load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.

The ability for a customer-generator's DER to provide these elements under a program with a utility would require complex control, communication, and management systems. The ability for DERs located on a distribution circuit in a net energy metering configuration to provide ancillary services would require customers to allow a utility to control the DER operation, be able to communicate the needs of the system, and have enough capacity responsive to system needs to beneficially effect the parameters of the utility system. This would reduce the amount of energy that the customer generator would otherwise produce since the system operator (the utility) would need to be able to ramp up and ramp down generation to create ancillary services. The generator would be controlled such that it is producing below its capacity to be able to ramp up on an instant's notice.

Battery storage can provide ancillary services as long as the utility controls the storage and there are not transmission or distribution capacity constraints that block the ability to use the battery when needed. However, the business case for using customer sited batteries that are fed from their solar generation for the sole purpose of ancillary services is poor. This stems from the relatively low value of ancillary services compared to the high value of the energy that the customer can consume from the storage and the fact that a certain quantity of battery capacity would not be available to the customer as it would need to be reserved for providing ancillary services.

The feasibility of developing these programs would depend on a cost-effective plan to address these specific capabilities of for system resource management, control and communication before the utility would be able to offer customer-generators a program to provide ancillary services. Currently, the DEC and DEP systems operate in reaction to the performance of the customer-generators' solar profile, utilizing utility system resources to provide ancillary services to the customer-generators.

Moreover, due to the intermittency of solar generation, customer-generators (or the utility if it controls the solar) would first need to reduce their own production volatility to reduce the ancillary services they currently consume before the Companies should consider development of an offer of a program for such services to be provided by the customer-generators.