BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 190

In the Matter of	)
	)
Biennial Consolidated Carbon Plan	)
and Integrated Resource Plan of	)
Duke Energy Carolinas, LLC, and	)
Duke Energy Progress, LLC,	)
Pursuant to N.C.G.S. § 62-110.9	)
and § 62-110.1(c)	)

DIRECT TESTIMONY AND EXHIBITS OF

JAKE DUNCAN

ON BEHALF OF

THE SOUTHERN ALLIANCE FOR CLEAN ENERGY,
THE NATURAL RESOURCES DEFENSE COUNCIL,
THE SIERRA CLUB, AND
THE NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

MAY 28, 2024

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I. Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Jake Duncan, and I am the Southeast Regulatory Director for Vote Solar. I work remotely from Chattanooga, TN. My business mailing address is 2201 Broadway, Fourth Floor, Oakland, CA 94612.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am submitting testimony on behalf of the Southern Alliance for Clean Energy, the Natural Resources Defense Council, and the Sierra Club, which are represented by the Southern Environmental Law Center, and on behalf of the North Carolina Sustainable Energy Association.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND WORK EXPERIENCE.

A. I have seven years of experience working on clean energy policy and analysis across a variety of roles. At Vote Solar, I lead regulatory and legislative efforts in North Carolina, South Carolina, and Tennessee. My work includes providing expert witness testimony, engaging in policy and program design efforts, and conducting public campaigns to promote access to clean energy technologies. Prior to Vote Solar, I spent four years at the Institute for Market Transformation where I worked with utilities, commercial real estate companies, and local governments to create policies and programs to advance energy efficiency in large buildings and supported cities' engagement at their public utility commissions. I have published two white papers regarding Integrated Resource Planning. I received a Master's degree in Climate Science and Policy from Bard College and a Bachelor's degree in Economics from Georgia College and State University. My resume is attached as **Exhibit JD-1**.

Q. HAVE YOU PROVIDED EXPERT WITNESS TESTIMONY IN PROCEEDINGS BEFORE THIS COMMISSION OR OTHER PUBLIC UTILITY COMMISSIONS?

A. I have submitted expert testimony to the North Carolina Utilities Commission (NCUC or Commission) for the Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP)) (together, the Company) Multi-Year Rate Plans in Docket Nos. E-7, Sub 1276 and E-2, Sub 1300, respectively, and to the South Carolina Public Service Commission regarding the DEC rate case in Docket No. 2023-288-E.

II. Testimony Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the role distributed energy resources (DER) play in meeting resource needs and to identify and evaluate any gaps in the Company's approach to integrating DERs in its proposed Carbon Plan Integrated Resource Plan (CPIRIP).

Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A. My conclusions are as follows:

- DERs can be integrated into the system quickly, reduce customer bills, reduce carbon emissions, and provide grid services. Effectively incorporating DERs into resource plans furthers least-cost planning principles.

- The Company did not incorporate behind the meter (BTM) storage in its CPRIP modeling, despite significant recent adoption and expected future growth in BTM storage adoption. Customers may choose to adopt and operate BTM storage on their own or may choose to participate in a utility or third-party program that compensates the customer for delivering grid services. I estimate that there may be at least 469 MW of BTM storage by 2038 that the Company's proposed CPIRP is not accounting for.
- The Company treated electric vehicle (EV) load asymmetrically by including the entirety of the EV load forecast but not accounting for managed EV charging programs.[1] I find that if 40% of EV load were to reduce their peak demand by 76%, in accordance with the results from a South Carolina pilot, the 2038 EV winter peak would drop from 820 MW to 569 MW and the 2038 EV summer peak would drop from 2,153 MW to 1,494 MW.
- The Company did not incorporate Virtual Power Plants (VPPs) into the proposed CPIRP, despite a growing body of evidence demonstrating VPPs may be a cost-effective resource. Incorporating emerging resources and modeling practices is consistent with the role resource plans play in introducing innovation into a regulated market.

[1] I am referring only to utility-managed EV charging programs. As I discuss in section, VI, the Company's Supplemental Planning Analysis updates the EV forecast to include a time of use EV rate in North Carolina (pages 17-22), which does reduce incremental EV peak demand.

- The Company has not incorporated Distribution Resource Planning (DRP) into the proposed CPIRP. DRP is a critical component to enabling the deployment of the maximum amount of cost-effective DERs. The Company's Integrated System and Operations Plan (ISOP) does not constitute a DRP.
- The Company has not adequately incorporated DERs or VPPs into the proposed CPIRP and therefore the proposed CPIRP does not meet least cost planning principles.

Q. WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMMISSION?

A. My recommendations are as follows.

- Regarding BTM battery storage, I recommend that the Commission require the Company to modify the proposed CPIRP to include a BTM storage forecast. At a minimum, I would recommend the Commission require the Company to incorporate BTM storage forecasts in its CPIRP filings going forward. These forecasts should delineate between naturally occurring BTM storage and storage associated with any current and future programs. Further, the Commission should require the Company to evaluate how incorporating BTM storage changes the model's selection of Combustion Turbines, and to adjust its near-term action plan accordingly.
- Regarding the EV load forecast, I recommend that the Commission 1) determine that the Company's current load forecast overestimates demand from EVs at system peaks and 2) require the Company to modify

the proposed CPIRP to include the impacts of managed EV charging and other viable EV load management programs on its EV load forecast and require such changes for all future CPIRP proceedings.

- Regarding Virtual Power Plants, I recommend that the Commission require the Company to work with stakeholders to conduct two modeling changes in the next CPIRP proceeding to incorporate VPPs and that the Commission establish a VPP goal. To that end, I would recommend the following. 1) In the next CPIRP proceeding, the Company should use the learnings from the PowerPair Pilot to develop and model a dispatchable BTM solar paired with storage program and model that as a selectable resource in the next CPIRP. This could include consideration of expanding PowerPair to commercial and industrial customers. 2) The Company should use the cost and operational profiles of existing and planned EE/DSM, DER, and other customer programs to create a series of VPP resources of different sizes and compositions and allow the CPIRP model to select VPP resources. 3) I recommend the Commission establish a VPP goal of 300 MW by 2030. Establishing such a goal sends a clear signal to the Company to consider VPP as a core part of its least cost resource strategy. I believe the scale of the proposed goal matches the scale of the challenge.
- Regarding Distribution Resource Plans, I recommend that the Commission require that the Company file a DRP as a part of their CPIRP,

and that the Commission establish specific goals and filing requirements for the DRP. I lay out a proposed framework in more detail in Section VIII.

III. Defining Distributed Energy Resources

Q. PLEASE STATE WHY IT IS IMPORTANT TO INCLUDE DISTRIBUTED ENERGY RESOURCES IN RESOURCE PLANS.

A. DERs[2] encompass a wide range of resources including BTM solar, BTM storage, energy efficiency, demand response, electric vehicles and more. DERs can be either a demand or supply side resource. DERs are a key part of any least-cost resource plan for the following reasons:

1. DERs provide energy and capacity to the system very quickly. DERs can be installed and interconnected much faster than the typical utility scale project.

2. DERs can provide valuable grid services such as avoided energy and capacity, ancillary services, reduced line loss, avoided transmission costs, and resilience.[3]

3. When a DER is a customer-owned resource, the entire system benefits from the grid services provided by the private capital investment.

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[2] North Carolina Code § 62-133.16 defines DERs as: "Distributed energy resource" or "DER" means a device or measure that produces electricity or reduces electricity consumption and is connected to the electric distribution system, either on the customer's premises or on the electric public utility's primary distribution system. A DER may include any of the following: energy efficiency, distributed generation, demand response, microgrids, energy storage, energy management systems, and electric vehicles.

[3] U.S. Department of Energy, Bulk Power, Distribution, and Grid Edge Services Definitions (Nov. 2023), https://www.energy.gov/sites/default/files/2023-11/2023-11-01%20Grid%20Services%20Definitions%20nov%202023_optimized_0.pdf.

4. DERs simultaneously benefit the system and reduce customer bills. For example, BTM solar paired with storage benefits the owner through lifetime energy bill savings and benefits the system through lower energy and capacity demand.

5. DERs generally reduce system level carbon emissions through zero carbon generation technology (like solar) or avoiding the use of fossil fuels-based generation (like energy efficiency).

6. Market transformation, federal investment, and growing customer interest in sustainability and energy independence are driving the growth of DERs regardless of the Company's action. Utilities have the duty to incorporate these trends into least cost resource planning and where feasible, develop programs to create market signals for customers to deliver grid services.

Q: HOW ARE AGGREGATED DERS A RELIABLE, PREDICTABLE RESOURCE?

A: When multiple DERs are aggregated, statistical principles apply. The aggregated performance of multiple DERs tends to follow a more predictable and consistent pattern than any particular DER standing on its own. Greater numbers of DERs reduce the impact of individual DERs' random fluctuations, making it easier to forecast overall performance; this is commonly referred to as the "law of large numbers." Aggregating DERs from different geographical areas can also help offset local weather-related variations. Finally, greater diversity in the load profiles of the customers using the DERs leads to a more predictable, overall load curve.

Q: WILL PRIVATE INVESTMENT IN DERS NECESSARILY PROVIDE GRID SERVICES?

A: No. Customers from all customer classes are using their own funds to install DERs to reduce their bills and increase their control over their energy consumption, which may or may not deliver grid services depending on whether, when, and to what extent energy consumption is reduced. Put simply, whether an individual DER provides benefits to the grid is typically incidental and is at best a secondary consideration for a DER owner. However, there is an opportunity for a utility or third-party provider to provide a financial mechanism to compensate DER owners for operating their resources in a manner that provides grid services. Therefore, individual DER adoption grows naturally, while dispatchable DERs and VPPs must be activated by the utility or the market.

Q. PLEASE DEFINE VIRTUAL POWER PLANTS AND EXPLAIN HOW THEY RELATE TO DERS.

A. A VPP is a coordinated network of distributed energy resources that collectively function to balance energy supply and demand, delivering reliable grid services akin to a conventional power plant.[4]

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[4] Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants at 6 (September, 2023), https://liftoff.energy.gov/wp-content/uploads/2023/09/20230911-Pathways-to-Commercial-Liftoff-Virtual-Power-Plants_update.pdf.

VPPs differ from DERs in two distinct ways. First, a VPP is designed and employed to provide specific grid services in the same manner as a traditional power plant. This is distinct from DERs in that DERs might provide grid services and provision of those services is not necessarily their primary function. Second, a VPP is an *aggregation* of DERs. The element of aggregation is important because aggregation combines the different operational profiles of DERs to provide specific grid services and allows the law of large numbers to increase the predictability of the aggregated whole.

A VPP may be comprised of one or more DERs. As such, a VPP can include customer owned DERs that are participating in a utility program or that are being operated by an independent third party outside an existing utility program.

The Commission recently approved an Active Load Management program in Dockets E-2 Sub 931 and E-7 Sub 1032.[5] The definition of Active Load Management is "the process by which Duke Energy utilizes any combination of voluntary demand side management programs or measures that allow for the aggregated control or management of distributed energy resources or controllable electrical devices at the grid

[5] Order Approving Revisions to Demand Side Management and Energy Efficiency Cost Recovery and Utility Incentive Mechanisms, *In the Matter of Application of Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69*, Docket No. E-2, Sub 931, and *In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Modifications to Residential Service Load Control Rider*, Docket No. E-7, Sub 1032. (N.C.U.C. May 22, 2024).

edge, whether directly by the utility or by a third party under contract with the utility, to enhance or maintain resource adequacy, reduce grid congestion, efficiently manage variable renewable energy output, and shape utility loads at a locational or aggregate level to benefit the utility system. Active Load Management programs or measures that have been approved by the Commission shall be eligible for recovery of prudently incurred program costs and Utility incentive earned."[6] For the purpose of my testimony, the Commission should consider "Active Load Management" and "Virtual Power Plants" to be interchangeable.

IV. A Brief Review of DERs in the Company's Proposed CPIRP

Q. PLEASE DESCRIBE HOW THE COMPANY INCLUDED DERS IN THE PROPOSED CPIRP.

A. The Company models DERs as a modification to the Company's load forecast. Some DERs, such as EE and BTM solar reduce the net load forecast while others, like EVs, may increase it. Table 1 summarizes the Company's approach.

Table 1: Inclusion of DERs in the IRP[7]

DER Type	Included in the Plan?	Mechanism	Scenarios	Scenario Use in EnCompass	Optimized in EnCompass?
BTM Solar	Yes	Reduction to load forecast	* In the filed plan, the Company did not describe any scenario analysis. * The Company confirmed	Only used in base scenario	No

[6] *Id*. at 11.

[7] Duke Proposed CPIRP, App'x C at 12-18.

			in its discovery responses that it conducted a base and high forecast.[8]		
BTM Batteries	No	N/A	N/A	N/A	N/A
Energy Efficiency	Yes	Reduction to load forecast	Yes, high (1.5%) scenario	Only used in the base scenario	No
Demand Side Management	Yes	Reduction to the load forecast	Yes, high and low scenarios	Only used in the base scenario	No
EV Load Management	No, other than NC TOU Rates	N/A	N/A	N/A	N/A
Virtual Power Plants	No	N/A	N/A	N/A	N/A

Q. HOW DO YOU THINK DERS SHOULD BE MODELED?

A. I believe DERs should be modeled according to whether or not they can be dispatched by the company.

Q. DO YOU BELIEVE IT IS APPROPRIATE TO MODEL NON-DISPATCHABLE DERS AS A DECREMENT TO THE LOAD FORECAST?

A. I believe the decision to model non-dispatchable DERs such as EE, BTM solar, and EV load as modifications to the load forecast is acceptable in the Company's 2023 CPIRP. Although VPPs provide more predictability, non-dispatchable DERs still provide energy and capacity savings in a relatively fixed (according to the technology) and predictable manner, lending credence to this method. However, some utilities and Commissions have

[8] Duke response to SACE et al. DR 17-4, attached as **Exhibit JD-2**.

elected to model non-dispatchable DERs as a selectable resource for various reasons,[9] and the Commission should keep this option in mind for future CPIRPs.

Q: DO YOU BELIEVE IT IS APPROPRIATE TO MODEL DISPATCHABLE DERS AS A SELECTABLE RESOURCE IN CPIRP MODELING?

A: Yes. Dispatchable DERs, such as standalone BTM storage, BTM solar paired with storage (SPS) and demand response,[10] have a known cost to the utility and a known operating profile, which makes them comparable to supply side investments from a modeling perspective.

Several utilities across the country have taken different approaches to modeling distributed storage as a resource.[11] One method is to simply create blocks of BTM storage capacity that can be deployed just like a demand response resource. Recognizing that not all BTM resources will be dispatchable, Portland General Electric (PGE) created separate dispatchable and non-dispatchable forecasts for BTM SPS and BTM

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[9] Takahashi, Kenji, Searching for Best Practices for Modeling Energy Efficiency in Integrated Resource Planning at e.g., 17 (Sept. 21, 2015), https://www.synapse-energy.com/sites/default/files/Modeling-EE-in-IRP.pdf; and NIPSCO, 2021 NIPSCO Integrated Resource Plan: Stakeholder Advisory Meeting #3 at e.g., 16 (July 13, 2021), https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/presentation-july-13-2021.pdf?sfvrsn=e7cf3651_14.

[10] Carvallo, J., and Schwartz, L., The use of price-based demand response as a resource in electricity system planning (Nov. 2023), https://eta-publications.lbl.gov/sites/default/files/price-based_dr_as_a_resource_in_electricity_system_planning_-_final_11082023.pdf.

[11] Miller, C & Twitchell, J., State of the Art Practices for Modeling Storage in Integrated Resource Planning. (Oct. 12, 2021), https://pubs.naruc.org/pub/CCBEFC58-1866-DAAC-99FB-3A405315FB9B.

storage. They then included the capacity from the dispatchable forecast in their capacity expansion modeling.

Q. DO YOU BELIEVE THE COMPANY ADEQUATELY INCORPORATED DERS INTO THE PROPOSED CPIRP?

A. No. The Company failed to adequately incorporate DERs in three ways. First, the Company did not include BTM storage. Second, the Company treated EVs asymmetrically by including the entirety of the forecasted load but excluding EV managed charging. Third, the Company did not include Virtual Power Plants.

Q. IS THIS CONSISTENT WITH THE COMPANY'S RECENT MULTIYEAR RATE PLANS?

A. No. In both Docket Nos. E-7 Sub 1276 and E-2 Sub 1300, the Company requested historically high levels of spending on grid modernization.[12] The Company, in part, justifies this level of spending as necessary to facilitate the integration of DERs.[13] However, the Company's CPRIP filing continues to downplay the contribution of DERs to least cost planning.

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[12] Direct Testimony of Jake Duncan and David Hill at e.g., 7:3-6, 12:19-16:10, *In the Matter of Application of Duke Energy Carolinas, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina and Performance-Based Regulation*, Docket No. E-7 Sub 1276, (N.C.U.C. July 19, 2023), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=17003ff8-9238-42c5-8b40-9ca9669e2fac; and Direct Testimony of Jake Duncan and David Hill at, e.g., 53:3-5, *In the Matter of Application of Duke Energy Carolinas, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina and Performance-Based Regulation*, Docket No. E-2 Sub 1300 (N.C.U.C. Mar. 27, 2023), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=91c7f5e1-9e47-4a3f-8329-089d21c5860c.

[13] Direct Testimony of Brent Guyton at e.g., Ex. 1, p.3, *In the Matter of Application of Duke Energy Carolinas, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina and Performance-Based Regulation*, Docket No. E-7 Sub 1276, (N.C.U.C. Jan. 19, 2023), https://starw1.ncuc.gov/NCUC/PSC/PSCDocumentDetailsPageNCUC.aspx?DocumentId=4c8a

V. Distributed Storage in the CPIRP

Q. DID THE COMPANY MODEL DISTRIBUTED STORAGE IN THE CPIRP?

A. No.[14] The Company declined to model distributed storage because of a perceived "lack of sufficient use case and profiles for combined [solar and storage] systems."[15] Regardless of the Company's decision, use of BTM storage is growing, and will impact the Company's system.

Q. PLEASE DESCRIBE THE ANTICIPATED GROWTH OF BTM STORAGE.

A. According to the Company, the storage attachment rates to BTM solar is approximately 10% in 2022, up from 1% in 2019.[16] The Solar Energy Industries Association (SEIA) states that current national pair rates are 12% in 2023, which is in line with North Carolina trends. SEIA projects that by 2028, 28% of BTM solar will be paired with storage nationally.[17] The main drivers for this trend are falling battery costs, increased interest in sustainability and resilience, and changing tariff structures. Lithium-Ion battery prices have fallen 82% since 2013,[18] and are forecasted to drop

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6d0c-b098-46ae-86c6-2b5ba3521b45&Class=Filing; and Direct Testimony of Brent Guyton at e.g., 8:8-9:2, *In the Matter of Application of Duke Energy Carolinas, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina and Performance-Based Regulation*, Docket No. E-2 Sub 1300 (N.C.U.C. Oct. 6, 2022), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=ade39ac6-536b-4619-afc8-b60ac49136dc.

[14] Duke response to SACE et al. DR 17-12, attached as **Exhibit JD-3**.

[15] *Id*.

[16] Direct Testimony of Duff and Byrd at 37.

[17] Solar Energy Industries Association, *Solar Industry Research Data*, https://www.seia.org/solar-industry-research-data (last accessed May 28, 2024).

[18] Bloomberg New Energy Finance, *Lithium-Ion Battery Pack Prices Hit Record Low of $139/kWh* (Nov 26, 2023), https://about.bnef.com/blog/lithium-ion-battery-pack-prices-hit-record-low-of-139-kwh/.

another 54% between 2023 and 2030.[19] Higher storage attachment rates are also consistent with the anticipated market response to the approval of the Solar Choice Tariffs (SCT) in both North Carolina and South Carolina. The SCT requires customers to take service under a time-of-use tariff. This creates a price-based incentive for customers to shift demand to off-peak times. As Witness Byrd stated in the DEC Multiyear Rate Plan application, the "TOU periods properly align price signals to the cost differences that exist across seasons and hours, encouraging peak load reduction and efficient system usage [and…] provide[s] the opportunity for economic use of battery storage in a manner aligned with system cost."[20] Customers can maximize the savings from a solar system by storing onsite generation to either minimize imports or export energy during peak and critical peak periods. Therefore, it is reasonable to expect more customers will adopt BTM storage over time.

Q. HOW DO YOU THINK BTM STORAGE SHOULD BE MODELED?

A. Behind the meter storage should be modeled differently depending on whether it is dispatchable by the utility. Absent a utility or third-party program to compensate customers for any grid services they provide,

[19] Goldman Sachs, *Lower battery prices are expected to eventually boost EV demand* (Feb 29, 2024), https://www.goldmansachs.com/intelligence/pages/even-as-ev-sales-slow-lower-battery-prices-expect.html.

[20] Direct Testimony of Jonathan L. Byrd at 15:9-13, *In the Matter of Application of Duke Energy Carolinas, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina and Performance-Based Regulation*, Docket Nos. E-7 Sub 1276, (N.C.U.C. Jan 19, 2023), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=2f6b3665-3a09-4b7b-bd7f-4626a604dba6.

customers who adopt BTM storage will operate the asset in their own interest – likely to reduce their energy bills and for resilience purposes (just as customers have purchased diesel generators for backup power supply). For the time being, BTM storage in this category should be modeled as a decrement to the load forecast. Although non-dispatchable storage will still benefit the system, the charging and export patterns will follow the customer's economic preferences. An example of this type of BTM storage is PowerPair Cohort A participants.

On the other hand, if the Company or a third party offers a program to operate BTM storage resources in a way that would provide grid services, those resources should be modeled as dispatchable supply side resources. Under such circumstances, BTM storage systems would have a clear cost to operate, would be able to provide specific grid services consistent with any program requirements, and would be considered dispatchable assets. An example of this type of BTM storage is PowerPair Cohort B participants.

As discussed earlier, Portland General Electric created two separate BTM storage forecasts based on dispatchability.

Q. HOW DOES NON-DISPATCHABLE BTM STORAGE IMPACT THE COMPANY'S LOAD FORECAST?

A. The use of BTM storage will reshape customer load profiles. On its own, storage will not materially change the *amount* of energy used by any one customer[21] but rather the time that energy is consumed. Barring participation in a program, how a customer operates their storage will be driven by the economics of the tariff structure they take service under and their personal preferences. Customers with solar plus storage systems who take service under the SCT will likely utilize their battery storage systems to minimize imports during the peak period. This will have a flattening effect on the load profile, reducing incremental peak demand per customer.

Q. DID YOU MODEL NATURALLY OCCURRING BTM STORAGE ADOPTION?

A. Yes. I estimate that there is likely to be approximately 469 MW of naturally occurring BTM storage by 2038 and 1,018 MW by 2050 across the Company's combined system. I arrive at these numbers by applying assumptions of battery storage attachment rates to the Company's BTM solar forecast contained in **Exhibit JD-4**.[22] First, I scaled current storage attachments rates observed by the Company to meet SEIA's 28% by 2028 for residential only. I then scaled residential attachments rates linearly to 50% in 2040, which is a more conservative assumption than continuing the rate of growth projected by SEIA. I also modeled a proportional trend to nonresidential attachment based on assumptions from Lawrence Berkeley

[21] Round trip efficiency from batteries will result in minor and predictable losses.

[22] Duke response to SACE et al. DR 17-3.

National Laboratory (LBNL),[23] reaching a 35% attachment rate in 2040. Table 2 provides the results by year. My methods are found in **Exhibit JD-5**. The impact of these customer owned resources is not reflected in the Company's proposed plan.

Table 2: Behind the Meter Battery Storage Forecast (MW)

	DEC NC	DEP NC	DEC SC	DEP SC	TOTAL
2024	5	4	1	0	10
2025	12	10	4	1	26
2026	22	18	7	1	48
2027	34	28	11	2	75
2028	49	40	15	3	108
2029	65	54	21	4	144
2030	83	69	27	5	184
2031	103	85	33	6	227
2032	124	103	39	7	273
2033	145	120	46	9	319
2034	164	136	52	10	362
2035	175	147	56	11	388
2036	185	157	59	12	413
2037	196	168	63	13	440
2038	208	179	67	14	469
2045	326	289	103	23	741
2050	451	399	137	31	1018

Q. PLEASE DEFINE "NATURALLY OCCURING" BTM STORAGE.

A. Naturally occurring BTM storage is storage that customers elect to procure of their own volition, without any utility incentives or financial return from participating in a VPP program. While it is not possible to entirely delineate between naturally occurring storage and potentially incentivized BTM

[23] Barbose, G., Darghouth, et al., Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States 2023 Edition (Sept. 2023), https://emp.lbl.gov/sites/default/files/emp-files/5_tracking_the_sun_2023_report.pdf.

storage in the future with my analysis, the adoption rate used in the forecast is consistent with current trends, which are not yet influenced by incentives or programs in the Carolinas. This forecast does not include batteries associated with the PowerPair and associated Energywise and PowerManager programs or any successor program.

Q. IS THERE ANYTHING MISSING FROM YOUR BTM STORAGE FORECAST?

A. Yes. My forecast does not include customers who adopt standalone storage or retrofit existing solar systems to add energy storage. These trends would increase BTM storage deployment beyond my forecast.

Q. WILL THE COMPANY HAVE ACTIONABLE DATA ON THE PERFORMANCE OF NON-DISPATCHABLE BTM STORAGE PAIRED WITH SOLAR BY THE NEXT CPIRP?

A. Yes. The PowerPair pilot program's Cohort A will provide important data on how customers chose to operate an SPS system under a time of use rate and no programmatic obligations. This information will enable the Company to remedy the "lack of sufficient use cases and profiles for [SPS]" and should thus be able to model BTM storage in the next CPIRP.

I will discuss the PowerPair pilot program and dispatchable BTM storage in greater detail later on in my testimony.

Q. WHAT IS THE IMPACT OF THE COMPANY'S DECISION TO NOT MODEL BTM STORAGE?

A. The Company is not accounting for hundreds of megawatts of battery storage assets that are likely to materialize on its system. These assets will drastically change the demand profile over the planning horizon. It is very possible that the Company's CPIRP model is overbuilding assets, particularly peaking Combustion Turbine assets, due to this error.

Q. WHAT IS YOUR RECOMMENDATION REGARDING DISTRIBUTED STORAGE?

A. I recommend that the Commission require the Company to modify the proposed CPIRP to include a BTM storage forecast. At a minimum, I recommend that the Commission require the Company to incorporate a BTM storage forecast in its next CPIRP filings. The forecast should delineate between naturally occurring BTM storage and storage associated with any current and future programs. Further, the Commission should require the Company to evaluate how incorporating BTM storage changes the model's selection of Combustion Turbines, and to adjust its near-term action plan accordingly.

VI. Electric Vehicle Managed Charging in the CPIRP

Q. PLEASE DESCRIBE HOW THE COMPANY APPROACHED EV LOAD IN ITS LOAD FORECAST.

A. From a forecast of EV adoption rates, the Company developed an energy and demand forecast based on anticipated use and vehicle class. The Company then added the entirety of the expected EV load growth as incremental load to the load forecast.

Q. DID THE COMPANY MODEL THE EFFECT OF EV LOAD MANAGEMENT PROGRAMS ON ITS EV LOAD FORECAST?

A. No.[24] While the Company does state that it anticipates including controllable winter peak in future Carbon Plans,[25] I believe it is improper to include the entirety of EV load but not include or account for any potential EV load management across the planning horizon, as this will inevitably lead to an over-forecast of EV load and the over selection capacity resources.

Q. DID YOU MODEL THE IMPACT THAT EV MANAGED CHARGING COULD HAVE ON THE LOAD FORECAST?

A. Yes. I developed a high-level forecast for the sole purpose of illustrating the importance of incorporating EV load management into the EV forecast. To do so, I applied findings from a South Carolina managed charging pilot to the Company's EV load forecast to estimate the potential for EV managed charging to reduce EV peak demand.

In order to estimate the per participating customer impact, I use the results of the South Carolina Off-Peak Credit pilot program that the Company stated in discovery "caused the average on-peak charging demand of program participants to reduce from approximately 0.17 kW before enrollment to less than 0.04 kW after enrollment."[26] This equates

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[24] Duke Proposed CPIRP, App'x H at 22.

[25] *Id*.

[26] Duke response to SACE et al. DR 17-15, attached as **Exhibit JD-6**.

to a post-program peak of 24% of the initial peak demand, or a 76% reduction. The Company further states that "the Companies believe that future iterations of similar programs across the Carolinas would likely yield similar results."[27]

In order to estimate the number of managed charging program participants, I adopt the assumption used in the Brattle Group's report, Real Reliability: The Value of Virtual Power, which evaluated the ability and costs for a VPP to provide resource adequacy services.[28] The report assumed that 40% of EV customers will participate in EV load management program by the mid-2030s.[29] I believe this is an appropriate participation level to assume for North Carolina since EV load management program adoption is within the Company's control. This analysis is based on total EV peak demand, which encompasses all EV classes. It is possible that different EV classes will not yield the same peak reduction results as the South Carolina pilot. In addition, different EV classes will likely participate in programs to different degrees. Again, I stress that the only purpose of this analysis is to illustrate the importance of including EV load management in the EV load forecast.

Table 3 includes results. **Exhibit JD-7** further describes my methods.

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[27] *Id*.

[28] Hledik, R. and Peters, K., *Real Reliability: The Value of Virtual Power, Volume II: Technical Appendix* (May 2023), https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power-Technical-Appendix_5.3.2023.pdf.

[29] *Id.* at 9.

I find that if 40% of EV load were to reduce its peak demand[30] by 76%, in accordance with the SC pilot results, 2038 EV winter peak demand would drop from 820 MW to 569 MW and 2038 EV summer peak demand would drop from 2,153 MW to 1,494 MW. In sum, EV managed charging is a peaking resource on the scale of 659 MW in the summer and 251 MW in the winter that are excluded from the CPRIP modeling. Incorporating these peaking resources may avoid or delay the need for other peaking resources, like a combustion turbine.

Table 3: Potential Impact of System Wide EV Managed Charging

YEAR	TOTAL DEC AND DEP EV PEAK (MW)		PARTICIPATING EV LOAD (MW)		REDUCTION DUE TO PROGRAM (MW)		POST EV MANAGED CHARGING PEAK (MW)	
	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer
2024	4	24	2	9	1	7	3	16
2025	9	53	4	21	3	16	6	37
2026	18	92	7	37	5	28	12	64
2027	30	147	12	59	9	45	21	102
2028	48	240	19	96	15	73	34	167
2029	85	325	34	130	26	99	59	226
2030	127	422	51	169	39	129	88	293
2031	180	611	72	244	55	187	125	424
2032	246	788	99	315	75	241	171	547
2033	325	977	130	391	99	299	225	678
2034	411	1173	165	469	126	359	285	814
2035	506	1537	202	615	155	470	351	1067
2036	607	1752	243	701	186	536	421	1216
2037	712	1958	285	783	218	599	494	1359
2038	820	2153	328	861	251	658	569	1494
2045	3628	4105	1451	1642	1110	1256	2518	2849
2050	5485	6015	2194	2406	1678	1840	3808	4175

[30] Duke response to PS DR 3-16, attached as **Exhibit JD-8**.

Q. IS THERE ANY EVIDENCE THAT RATES CAN ALSO REDUCE EV PEAK LOAD?

A. Yes. The Company included North Carolina time of use EV rates in the supplemental modeling, which reduced cumulative EV winter peak load among participating customers by 12% and summer peak by 24% in 2038.[31]

Q. WHAT IS THE IMPACT OF THE COMPANY'S ASYMMETRIC TREATMENT OF EV LOAD?

A. The Company is likely over-forecasting peak demand from EVs. This means the Company's model may be over-selecting capacity assets.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MANAGED EV CHARGING?

A. I recommend that the Commission 1) determine that the Company's current load forecast overestimates demand from EVs and 2) require the Company to modify the proposed CPIRP to include the impacts of managed EV charging and other viable EV load management programs on its EV load forecast and continue to require such changes for all future CPIRP proceedings.

VII. Virtual Power Plants in the CPIRP

Q. DID THE COMPANY MODEL VIRTUAL POWER PLANTS IN ITS PROPOSED CPIRP?

A. No.

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[31] Duke response to SACE DR 17-7-4, attached as **Exhibit JD-9**.

Q. DOES THE COMPANY HAVE ANY CURRENT OR PLANNED PROGRAMS OR PILOTS THAT COULD BE CONSIDERED A PART OF A VIRTUAL POWER PLANT?

A. Yes. The Company is operating or has concluded some pilot programs that could be considered part of a VPP.

Due to the Commission's foresight and leadership, the Company has recently deployed the PowerPair pilot program. PowerPair provides up-front incentives for both BTM solar and storage for residential customers. Importantly, PowerPair will study the performance of solar paired with batteries in two scenarios – one cohort on the Solar Choice time of use rate with full control of their battery and another cohort in which the customer enrolls their battery in a demand response program called Power Manager for DEC, and EnergyWise for DEP, and is not enrolled in a TOU rate. The cohort that participates in Power Manager and EnergyWise can be considered a VPP because the Company will dispatch customers' batteries in aggregate, while the other cohort will provide insight into non- dispatchable batteries.

Further, the Company is running the EV Residential Home Charging Plan Pilot[32] which provides a flat bill for EV charging and allows the Company to stop customer charging up to three times per month. The Company has proposed a vehicle-to-grid pilot that will begin operations in

[32] Duke Energy, *Duke Energy to pilot EV charging subscription service in North Carolina* (Aug. 28, 2023), https://news.duke-energy.com/releases/duke-energy-to-pilot-ev-charging-subscription-service-in-north-carolina .

2025. Duke Energy Florida has a Backup Generator Program[33] which provides bill credits to customers for utilizing backup generators during peaks and has operated a Bring Your Own Battery[34] pilot program.

While these individual pilots and programs are invaluable for the Company to learn how to operate different DERs and are consistent with the VPP concept, the Company has not yet scaled these individual programs for a significant number of customers or considered VPPs in its CPIRP modeling.

Q. DO YOU BELIEVE THE COMPANY SHOULD IMMEDIATELY SCALE VPP PROGRAMS?

A. Yes. The Company has conducted or is conducting several VPP pilots and has requested approval for a Rapid Prototyping pilot structure. The scale of the resource needs required to meet the goals of HB 951 in a period where the Company has forecasted significant load growth necessitates swift movement at scale. I believe that the Company should immediately, or at the conclusion of any successful pilot, scale each DER or VPP program to its maximum cost-effective size in order to meet load at least cost.

Q. PLEASE DESCRIBE HOW VIRTUAL POWER PLANTS SHOULD BE DEPLOYED IN NORTH CAROLINA TO SAVE RATEPAYER MONEY.

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[33] Duke Energy, *Backup Generator Program*, https://www.duke-energy.com/business/products/backup-generator-program?jur=FL01 (last accessed May 28, 2024).

[34] Duke Energy, *Duke Energy launches 'Bring Your Own Battery' study to test potential improvement of energy resiliency in Florida* (Jan. 20, 2022), https://news.duke-energy.com/releases/duke-energy-launches-bring-your-own-battery-study-to-test-potential-improvement-of-energy-resiliency-in-florida .

A. As I briefly described earlier, a critical element that differentiates VPPs from historical approaches to DERs or demand response is the express purpose of a VPP to deliver a broader array of grid services. The basic concept is that, if the unique characteristics of the variety of DERs are aggregated at scale, correctly aligned, compensated, financed, and operated, the VPP could provide specific grid services at a known cost, which could avoid the need for higher-cost fossil fuel resources while maintaining reliability.

VPPs may be particularly useful if there is a scenario in which there is a resource adequacy need for a small number of hours per year. VPPs may outcompete a new Combustion Turbine that may otherwise be selected by the model to run for a few select hours each year, if VPPs have lower capital and operating costs.

Q. WHAT MODELING CHANGES ARE NEEDED TO FULLY EMBRACE VPPS?

A. To date, the variety of EE/DSM, grid edge, and other customer programs offered by the Company have been modeled as separate elements of the IRP modeling. To parcel out a specific amount of a VPP to be made a selectable resource the IRP modeling, the Company would have to combine certain programs with desired qualities together into a single resource that represents the sum of the individual programs.

To do so, the Company could create a variety of VPP resources of different sizes and compositions for selection. The different VPP resources would have different costs and operational structures based on the programs that comprise each VPP resource.

Consider an illustrative example of a 50 MW VPP resource comprised of 40 MW of PowerPair solar and storage, 10 MW of EV managed charging, 1 MW of EV vehicle to grid, 15 MW of smart thermostat demand response, and 5 MW of traditional energy efficiency measures. This VPP is oversized to account for resource adequacy needs and any marginal errors in customer participation. The variety of DERs in the VPP means the VPP, particularly when selected with other VPPs, could reliably offer the peak shaving necessary to compete with a combustion turbine. The model may then select this illustrative VPP or other VPPs in lieu of other resources, to defer or downsize the selection of other resources at net savings to the system, or not at all.

While a VPP may (or may not) need to be oversized to provide a specific amount of capacity or other grid service, it is important to note that 1) whether or not and to what extent a VPP needs to be oversized will become more known and predictable over time as the Company gains experiencing with operating and modeling VPPs and 2) traditional fossil fuel plants are already oversized, as no plant, especially not a Combustion Turbine, runs at 100% capacity factor. What matters is whether or not a VPP, even if it is oversized, is more cost effective than alternatives.

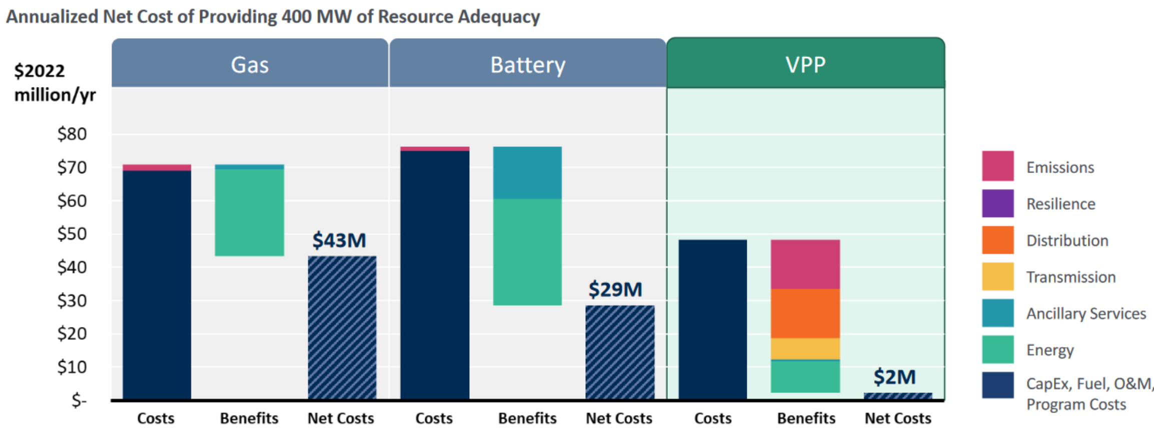
Q. IS THERE ANY EVIDENCE THAT APPROPRIATELY MODELING VPPS CAN REDUCE RESOURCE PLAN COSTS?

A. Yes. The Brattle Group has published two reports that use sophisticated modeling to assess the potential for VPPs to provide resource adequacy and capacity services.

First, the Brattle National VPP Study[35] report assessed VPPs at a national level. The analysis used only existing residential demand response applications, specifically smart thermostats, smart water heating, home managed EV charging and BTM batteries. Brattle compared the net cost to provide 400 MW of resource adequacy services (meeting load for the top 63 hours of demand in a year for an illustrative utility system) of this VPP portfolio against two different alternatives: a utility scale battery and a combustion turbine. Using rigorous and realistic customer participation assumptions, Brattle found that the VPP provides resource adequacy services more cost effectively than either a CT or a utility scale battery (Figure 1).

[35] Hledik, R. and Peters, K., *Real Reliability: The Value of Virtual Power* (May 2023), https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf.

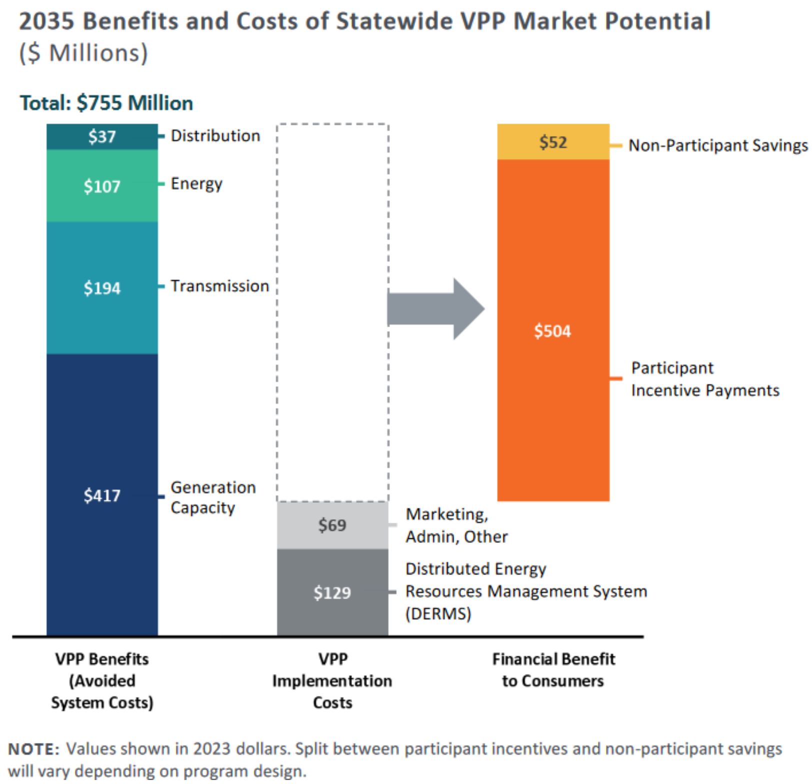
Figure 1: Virtual Power Plant Resource Adequacy Assessment



Second, the more recent Brattle California Study[36] developed a VPP potential for the state. The California Study's VPP included five measures and included commercial and industrial demand response. The California Study used even more granular, state specific data to develop the VPP resources and then simulated 8,760 hourly dispatch to determine costs and benefits. The analysis found that VPPs could cost effectively meet 15% of the state's 2035 peak demand. Importantly, doing so with VPP provides direct benefits to customers through incentive payments for program participants (Figure 2). Accordingly, VPPs represent a solution to meet peak demand that lowers, instead of increases, customers' bills.

[36] Hledik, R., Peters, K. & Edelman, S., *California's Virtual Power Potential: How Five Consumer Technologies Could Improve the State's Energy Affordability* (April 2024), https://www.brattle.com/wp-content/uploads/2024/04/Californias-Virtual-Power-Potential-How-Five-Consumer-Technologies-Could-Improve-the-States-Energy-Affordability.pdf.

Figure 2: California's Virtual Power Plant Market Potential



Q. HOW COULD THE COMPANY INCORPORATE POWERPAIR INTO FUTURE CPIRPS?

A. By the next CPIRP filing, the Company will have developed significant insight into the cost of running the PowerPair program, and how customer owned resources operate under the required tariff and programs. The Company "would expect [PowerPair] to be included in the Companies' next CPIRP."[37]

However, I believe the Company should go further than simply including the existing PowerPair in future modeling. The Company should create a PowerPair "resource" that can be selected by the EnCompass

[37] Direct Testimony of Duff and Byrd at 26.

capacity expansion modeling in certain MW increments. If the "PowerPair" resource is more cost-effective than other resources given its operational characteristics and its ability to leverage private investment, EnCompass could be expected to select a portfolio of system resources that includes compensated BTM and solar paired with storage systems to meet system needs at least cost. If this is indeed the case, the Company should pursue this option in the interest of least cost planning.

Q. PLEASE ELABORATE ON WHY THE COMPANY SHOULD MODEL VPPS TO FURTHER LEAST COST PLANNING.

A. Although I am not a lawyer, it is my understanding that resource and carbon reduction planning under HB 951 must comply with least cost planning principles. Rule R8-60A provides that a public utility "…shall include …a comprehensive analysis of all resource options…"[38] and that a public utility "…shall consider and compare a comprehensive set of potential resource options, including both demand-side and supply-side options, to determine the least cost combination (on a long-term basis) of resource options for reliably meeting the anticipated needs of its system…."[39] In addition, NCGS § 62-2 states: "It is hereby declared to be the policy of the State of North Carolina:. . . (3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand side options, including but not limited to

[38] N.C. Utils. Comm'n Rule R8-60A(d)(3).

[39] N.C. Utils. Comm'n Rule R8-60A(d)(5).

conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills…."

As demonstrated in my testimony, VPPs are a viable resource to model and may result in a lower cost plan. Therefore, consistent with least cost principles, the Company should model VPPs in its next CPIRP.

Further, since the Company is a regulated monopoly and does not face market competition, I believe that the CPIRP is an important avenue to emulate the market forces that would otherwise cause non-monopoly companies to innovate. Using the CPIRP to explore innovative cost reduction solutions is core to the purpose of integrated resource planning and is in the public interest.

Q. PLEASE COMMENT ON THE RECENTLY APPROVED CATEGORY OF ACTIVE LOAD MANAGEMENT IN THE DSM/EE COST-RECOVERY MECHANISM.

A. I applaud the Commission for its decision to approve the Active Load Management language in the Demand-Side Management and Energy Efficiency Mechanism. This new category will provide the Company with an important avenue to learn how to effectively deploy VPP programs. The measurement and verification will provide critical data to enable accurate

VPP modeling. I do not think that any of my recommendations are mutually exclusive to the new Active Load Management definition in the Mechanism. Indeed, I believe that procuring 20 MW or more under this category of programs will enable the Company to meet my recommendations.

Q. WHAT DO YOU RECOMMEND REGARDING VPPS?

A. I recommend that the Commission require the Company to work with stakeholders to conduct at least two modeling changes in the next CPIRP to incorporate VPPs and that the Commission establish a VPP goal.

First, the Company should use the learnings from the PowerPair Pilot to develop and model a dispatchable BTM solar paired with storage program and model that as a selectable resource in the next CPIRP. This could include consideration of expanding PowerPair to commercial and industrial customers.

Second, the Company should use the cost and operational profiles of existing and planned EE/DSM, DER, and other customer programs to create a series of VPP resources of different sizes and compositions and allow the CPIRP model to select VPP resources.

Third, I recommend the Commission establish a VPP goal of 300 MW by 2030. Establishing such a goal sends a clear signal to the Company to consider VPP as a core part of its resource strategy. This scale is attainable and matches the scale of the challenge. This will give both the Company and the Commission significant insight into how the market could meet grid needs.

Q. WHY DO YOU THINK IT IS APPROPRIATE FOR THE COMMISSION TO SET A VPP GOAL?

A. First, I believe it is within the Commission's jurisdiction to do so. Second, it is an acceptable practice for commissions to set goals for the utilities they regulate. For example, in 2017, the Minnesota Public Utilities Commission (MNPUC) set a goal for Xcel Energy Minnesota to acquire 400 MW of demand response resources by 2023 and to explore the potential for up to 1,000 MW of DR.[40] While Xcel did not meet this target, it did add a significant amount of DR resources, and the stakeholder and docketed processes initiated to meet this goal has led to important changes to Xcel's DR approach.[41]

Q. WHAT FACTORS EXIST THAT INDICATE THE DEPLOYMENT OF VPPS CAN BE DEPLOYED ON THE TIME FRAME YOU ARE SUGGESTING?

A. First, the company will gain significant experience in deploying VPPs in the next few years. Both PowerPair and new programs under the active load management designation will result in at least 50 MW of VPPs in the next few years.[42] Second, the private sector is rapidly gaining expertise in the

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[40] MNPUC Commission Order at Order Points 10, 14, Docket RP-15-21 (MN PUC, Jan. 11, 2017), https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={978E98E8-C6BD-4851-80E2-14ED10400D48}&documentTitle=20171-128000-01.

[41] Staff Briefing Paper, Docket E999/CI-22-600 (MN PUC, Aug. 23, 2023), https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={B0F7FE89-0000-C11C-B9AB-2CE1B0A40E68}&documentTitle=20238-198279-01.

[42] This 50 MW accounts for 20 MW of Active Load Management and 30 MW derived from PowerPair, assuming that the 60 MW total allowed solar capacity of PowerPair is split evenly between Cohort A and B. PowerPair is subject to a maximum split of 80/20 between cohorts, so

rapid deployment of VPPs. Third-party aggregators have a natural incentive to scale the business in quick but dependable fashion. For example, the company Uplight enrolled nearly 50,000 customers delivering 30MW of capacity in only 3 months.[43] Third-party providers are skilled at enrolling customers and are capable of deploying their own technology and programs. As such, I believe VPP procurement should be open to third parties.

VIII. Distribution Resource Planning: A Missing Piece of the Puzzle

Q. PLEASE DEFINE DISTRIBUTION RESOURCE PLANNING.

A. There is no definition for Distribution Resource Plan (DRP) in North Carolina statute. Nineteen states and the District of Columbia have established some form of DRP either through legislation or Commission action.[44] While there is no single definition used across these jurisdictions, LBNL broadly defines DRP as "[A] plan that] evaluates benefits and costs of DERs, considers ways to increase deployment of cost-effective DERs, and facilitates better integration of DERs in distribution planning."[45]

PowerPair Cohort B could be as high as 48 MW. Further, the capacity limit is set by the solar capacity and dispatchable battery capacity could vary.

[43] Hledik, R. et al., *Virtual Power Plants: Resource Adequacy without Interconnection Delays*, Utility Dive, (Aug. 17, 2023), https://www.utilitydive.com/news/virtual-power-plants-vpp-distributed-energy-resource-adequacy-der-distributed-energy/691135/.

[44] Lawrence Berkeley National Laboratory, *State Distribution Planning Requirements*, https://emp.lbl.gov/state-distribution-planning-requirements.

[45] Schwartz, L & Mims Frick, N., *Integrated Distribution System Planning Overview* at 7 (Mar. 20, 2024), https://eta-publications.lbl.gov/sites/default/files/schwartz-frick_idsp_overview_20240320_rev.pdf.

Q. WHAT ARE THE COMMON ELEMENTS OF DRPS?

A. The DRPs in these jurisdictions vary, but generally share a set of procedural requirements and filing or substantive requirements.[46] The procedural requirements address where and when the DRP is filed, the relevant planning horizon(s), and specifics on how certain data is shared. The filing requirements designate what is considered within the DRP. These may include establishing baseline data, describing the distribution system and DER planning process, establishing data access guidelines and parameters, a DER forecast, a hosting capacity analysis, creating locational value to geotarget DERs, a grid needs assessment, a non-wires alternative framework, near term and long-term plans, guidelines or requirements for pilot projects, an environmental justice assessment, and guidelines for stakeholder and community engagement.

Q. DOES THE COMPANY CURRENTLY CONDUCT A DRP?

A. No. The Company does conduct an "Integrated System and Operations Plan" (ISOP).[47] However, ISOP is not a term used anywhere else in the electric or utility industry in the United States. Table 4 demonstrates how

[46] Mims Frick, N., *A National Perspective on State Practices for Integrated Distribution System Planning* at e.g., 11-12 (Jan 4, 2024), https://eta-publications.lbl.gov/sites/default/files/frick_dsp_md_final.pdf; and Lawrence Berkeley National Laboratory, *State Distribution Planning Requirements*, https://emp.lbl.gov/state-distribution-planning-requirements (last accessed May 27, 2024).

[47] The Company defines ISOP as "the planning framework that optimizes capacity and energy resource investments across generation, transmission, distribution and customer solutions for [the Company]." Duke Proposed CPIRP, App'x G at 1.

ISOP does not meet the majority of the standard DRP elements. Therefore, the Commission should not consider ISOP to be a DRP.

Table 4: ISOP - DRP Comparison

Common DRP Requirement	Discussion of the Company's IRP
Stakeholder Engagement on Distribution Planning	The Company's CPIRP engagement did not address distribution issues. The Company's ISOP engagement continues to be a largely one-way form of communication in which finalized process are presented to stakeholders instead of collaboratively created.[48]
Baseline Data Sharing	The Company filed minimal, actionable distribution system or DER data in its CPIRP filing.
Community Engagement Plan	The Company does not include or propose a community engagement plan with regard to the distribution system or DERs.
DER and Electrification Scenario Analysis	The Company did not conduct sufficient DER or electrification scenario analysis, nor did the Company incorporate existing EV load management programs in its EV load forecast.
Locational Benefits and Costs of DERs	The Company does not leverage any locational benefits or costs for distributed energy resources. The Company has used location specific analysis for utility scale battery storage for non-wires projects[49] – however, this does not mean the Company accounts for the locational benefits or costs of customer-sited DERs.
Hosting Capacity Analysis	The Company is developing a "Grid Hosting Capacity Analysis" pursuant to settlement agreements in both NC and SC.
Non-Wires	The Company has developed a non-wires analysis approach largely

[48] *See generally* Direct Testimony and Exhibits of David Hill and Jake Duncan, on Behalf of North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Vote Solar, *In the Matter of Application of Duke Energy Progress, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-2, Sub 1300 (N.C.U.C. March 27, 2023), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=91c7f5e1-9e47-4a3f-8329-089d21c5860c.

[49] Duke response to SACE et al. DR 17-11, attached as **Exhibit JD-10**.

Identification and Proposals	without stakeholder input[50] and, to date, has not identified any actionable projects.
Energy Justice Evaluation	The Company has not evaluated the energy or environmental justice impacts of their distribution system.
Near Term DER Action Plan	The Company does list several action items in Appendix H: Grid Edge and Customer Programs. However, many of the key themes discussed in this testimony are missing from the execution plan.
Long Term Distribution Investment Plan	The Company proposes distribution investments in rate cases. The Company has proposed three-year grid investment plans in the most recent rate cases. However, these plans are often contested and have not thematically changed since the first proposal in 2017.[51]

Q: HAVE THERE BEEN ANY INDEPENDENT REVIEWS OF THE COMPANY'S ISOP?

A: Yes. A report[52] from LBNL and National Renewable Energy Laboratory (NREL) compares Duke's ISOP with other distribution planning best practices. The report was prepared for the South Carolina Office of Regulatory Staff (ORS), with the authors interviewing staff from the ORS, the North Carolina Public Staff, and the Company.

The report also outlined a number of recommendations that broadly reflect the need for a clear DRP framework and associated, substantive

[50] *See generally* Direct Testimony and Exhibits of David Hill and Jake Duncan, on Behalf of North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Vote Solar, *In the Mater of Application of Duke Energy Progress, LLC, for and Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-2, Sub 1300 (N.C.U.C. Mar. 27, 2023), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=91c7f5e1-9e47-4a3f-8329-089d21c5860c.

[51] *Id.* at 35-55.

[52] Grid Modernization Initiative, U.S. Dep't of Energy, Duke Energy's Integrated System and Operations Planning: A comparative analysis of integrated planning practices (June 2023), https://eta-publications.lbl.gov/sites/default/files/gmlc_4.2.2_memo_20230628_final.pdf.

improvements, better stakeholder engagement, and alternative methods to better forecast and leverage DERs. The authors state that "ISOP does not contain all of the elements of IDP that a growing number of states are adopting to maintain and enhance reliability and resilience and minimize electricity system costs."[53] While some of these elements may be contained in other filings, such as a rate case, the point is that ISOP does not represent a comprehensive DRP. The authors go on to state: "there is no clear information on how the portfolio of planned investments across these domains – including potential non-traditional solutions – will balance competing objectives such as cost, risk, and reliability."[54]

The report also commended the Company for the innovative aspects of the Company's ISOP work, such as their circuit level forecasting, with which I concur.

Q. PLEASE DESCRIBE HOW ESTABLISHING DRP GUIDELINES WOULD ENABLE THE COMPANY TO MEET ITS CPIRP REQUIREMENTS MORE COST EFFICIENTLY.

A. The Company's proposed CPIRP does not maximize the use of cost-effective DERs. I believe that requiring a DRP with clear reporting requirements to be filed within the CPIRP would be consistent with least cost planning principles.

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[53] *Id.* at 29.

[54] *Id.* at 28.

First, a DRP would help establish locational value for DERs, which would help the Company co-optimize between distribution and transmission system level assets. Research suggests that incorporating distribution level DERs into capacity expansion modeling, which normally excludes distribution level assets, could reduce system costs.[55] Second, a DRP would be a key avenue for the Company and stakeholders to conduct the considerable amount of work necessary to meet the proposed 300 MW VPP goal, should the Commission choose to adopt it. The Department of Energy suggests DRPs are an important element to enable VPP deployment.[56] Finally, as most customers interact directly with the distribution system, the DRP would be an important avenue for the Company to gain a better understanding of their customers their needs, and to develop innovative, cost-effective solutions to meet customer needs and provide grid services.

Q: IS IT APPROPRIATE FOR THE NCUC TO REQUIRE DUKE TO PREPARE A DRP?

A: Yes. While I am not a lawyer, I understand that the applicable CPIRP rules require a comprehensive assessment of all resource options, and DERs

[55] Clack, C. et al., Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid at e.g., 3 (Dec. 1, 2020), https://vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_TR_Final.pdf.

[56] *See* U.S. Dep't of Energy, Pathways to Commercial Liftoff: Virtual Power Plants at 54 (Sept. 2023) https://liftoff.energy.gov/wp-content/uploads/2023/09/20230911-Pathways-to-Commercial-Liftoff-Virtual-Power-Plants_update.pdf#LIFTOFF_DOE_VVP_11092023_v3.indd%3A.21910%3A739.

are an available resource option.[57] Furthermore, I understand the CPIRP rules to establish the minimum requirements for a CPIRP—a floor rather than a ceiling—and I see no reason that they would prohibit the Commission from requiring a DRP, particularly when it serves least-cost planning as I just described.

Q: WHAT ARE YOUR RECOMMENDATIONS REGARDING A DISTRIBUTION RESOURCE PLAN?

A: I recommend that the Commission require that the Company develop a distribution resource plan with stakeholder input and file it as a part of their CPIRP, and that the Commission establish specific goals and filing requirements for the DRP. To establish those goals and filing requirements, I would provide the following suggestions:

DRP goals should include but are not limited to:

- To improve grid reliability and resilience, and ensure all customers receive satisfactory reliability services.
- To increase customer choice and engagement in energy services, including commercial vehicle fleet electrification, which can have significant impacts on the distribution grid.
- To support DER integration and utilization of grid services.
- To accelerate deployment of new technologies and services to optimize grid performance and minimize electricity system costs.

[57] N.C. Utils. Comm'n Rule R8-60A(d)(3).

- To develop robust modeling methods that represent the benefits and costs of distribution level generation, load shifting, and load reduction.

Filing requirements should include but are not limited to:

- Baseline data sharing of the distribution system, recent investments, DER penetration and potential.
- Forecasts of DER adoption and electrification, including at least two potential planning scenarios, a baseline scenario and a scenario of high-penetration of distributed energy resources and end-use electrification. Scenarios should reflect a reasonable mix and require that the Company develop a distribution resource plan of individual and aggregated distributed energy resources, dispersed geographically across a utility's distribution system.
- A hosting capacity analysis consistent with best practices,[58] including a method to share underlying data while maintaining privacy.
- An evaluation of locational benefits and costs of DERs.
- A community engagement plan.
- An energy justice evaluation of the distribution system and DERs.
- A near term action plan that includes proposed program, tariff and technology solutions for distribution grid needs over the next two years.

[58] *See* generally Interstate Renewable Energy Council, *Key Decisions for Hosting Capacity Analyses* (Sept. 16, 2021), https://irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/.

- A long-term plan that outlines the Company's distribution investments and methods of addressing the broader goals of maximizing reliability, customer benefits, and distribution system efficiency.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony and Exhibits of Jake Duncan on Behalf of the Natural Resources Defense Council, the Sierra Club, the Southern Alliance for Clean Energy, and the North Carolina Sustainable Energy Association, either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 28th day of May, 2024.

/s/ Nick Jimenez

EXHIBIT JD-1
E-100, SUB 190

Jake Duncan

Jduncan@votesolar.org | Chattanooga, TN

Professional Experience

Vote Solar, Southeast Regulatory Director
Remote — June 2022 - Present

- Leads regulatory and legislative efforts in North and South Carolina to advance a rapid, cost-effective, equitable transition to a carbon free power system.
- Engages in rate cases, resource plans, grid plans, and program design efforts.
- Develops testimony, comments, and coalition positions through qualitative and quantitative analysis.
- Engages with community-based organizations and coalitions across the Carolinas.
- Provides thought leadership through organized speaking events and public communications.

Institute for Market Transformation, Senior Associate — August 2018 – May 2022
Washington, DC

- Co-developed IMT's power sector strategy, which focuses on supporting broader regulatory engagement, expanding utility regulator's legislative mandate to include climate and equity, and using building performance policies to advance utility reform.
- Supported local government and community partner's engagement in regulatory proceedings with a focus on climate and equity, including intervention in utility resource planning, distribution planning and data access proceedings; co-authoring comments; co-creating and supporting two advocacy coalitions.
- Managed two peer-learning groups within the Urban Sustainability Director's Network on grid flexibility and data access.
- Directly assist local governments as they design, pass, and implement building performance policies.
- Managed a Department of Energy sponsored field study on building codes in the Southwest.
- Led the development of several proposals, including a $9 million, multi-year proposal to the Department of Energy's Connected Communities program.
- Developed a spreadsheet-based model to assess the impact of building performance standards on the national building stock.
- Supported the Green Lease Leaders program and Small Business Energy Initiative.

Resources for the Future, Future of Power Fellow — June - August 2018
Washington, DC

- Published a report on how utility planning processes view and integrate demand side management approaches compared to supply side investments.

Natural Capitalism Solutions, Policy and Research Intern — March - August 2016

- Supported the Presidential Climate Action Project, which advanced opportunities for climate action using executive authority under the Obama Administration.

Solar Energy Industries Association, Research Intern — Summer 2015
Washington, DC

- Managed the National Solar Database.
- Collected and organized data about solar industry growth.
- Contributed to the Solar Market Insight Report.

Relevant Filings

- South Carolina Public Service Commission (Docket 2023-388-E). In the matter of Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates, Adjustments in Electric Rate Schedules and Tariffs, and Request for an Accounting Order. Direct Testimony of Jake Duncan. April 8, 2024.
- North Carolina Utilities Commission (Docket E-2 Sub 1300). Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation. Direct Testimony of Jake Duncan and David Hill. March 27, 2023.
- North Carolina Utilities Commission (Docket E-7 Sub 1276). Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation. Direct Testimony of Jake Duncan and David Hill. July 19, 2023.
- Oregon Public Utilities Commission (Docket UM 2005, 2197, and 2198). Investigation into Distribution System Planning, Comments of Verde, Coalition of Communities for Color, and Institute for Market Transformation. Dec 3, 2021.
- Minnesota Public Utilities Commission (Docket No. E-002/M-21-694). Xcel Energy's 2021 Integrated Distribution Plan, Comments of the City of Minneapolis. February 25, 2022.
- Minnesota Public Utilities Commission (Docket No. E002/RP-19-368). 2020-2034 Xcel Energy Upper Midwest Integrated Resource Plan, Comments of the City of Minneapolis. Feb 11, 2021.
- Minnesota Public Utilities Commission (Docket No. E002/RP-19-368). 2020-2034 Xcel Energy Upper Midwest Integrated Resource Plan, Comments of the Coalition of Minnesota Local Governments and the Suburban Rate Authority. March 12, 2021.

Relevant publications

- Duncan, J and Eagles, J. 2022. Public Utility Commissions and Consumer Advocates: Protecting the Public Interest. *National Association of Utility Regulatory Commissioners.*
- Duncan, J., Eagles, J., Farnsworth, D., Shenot, J., & Shipley, J. 2021. Participating in Power: How to Read and Respond to Integrated Resource Plans. *The Institute for Market Transformation and the Regulatory Assistance Project.*
- Debelius, H., Duncan, J., Gahagan, R., Kirby, K. & White, A. 2020. New Leasing Languages - How Green Leasing Programs Can Help Overcome the Split Incentive. *American Council for an Energy Efficient Economy*.
- Crandall, K. and Duncan, J. 2019. Local Government Engagement with Public Utility Commissions. *National Association of Utility Regulatory Commissioners.*
- Bonulgi, C., Crandall, K., Duncan, J, & Etter-Wenzel, C. 2019. Utilizing City-Utility Partnership Agreements to Achieve Climate and Energy Goals. *The Institute for Market Transformation and the World Resources Institute.*
- Burtraw, D. and Duncan, J. 2018. Does Integrated Resource Planning Effectively Integrate Demand-Side Resources? *Resources for the Future.*

Education

MS in Climate Science and Policy — May 2019
Bard College, Annandale-on-Hudson, NY

BS in Economics — December 2015
Georgia College, Milledgeville, GA

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Did the Companies perform any scenario analysis regarding the updated net metering forecast? If so, please provide all associated workpapers in excel format with formulas intact.

Response:

High scenarios were developed when the updated net metering forecasts had been created. Please see the attached files identified as SACE_DR17-4_DECNC.xlsx, SACE_DR17-4_DECSC.xlsx, SACE_DR17-4_DEPNC.xlsx, and SACE_DR17-4_DEPSC.xlsx which present the data from the high scenarios.

Responder: Bryan J. Dougherty, Principal Structuring Analyst

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Did the Companies model behind-the-meter battery storage? If so, please describe (1) the methodology the Companies used and (2) the manner in which behind-the-meter storage was incorporated in the CPIRP. Please provide the workpapers for behind-the-meter battery storage modeling in excel format with formulas intact.

Response:

The Companies did not specifically model BTM battery storage due to the lack of sufficient use cases and profiles for combined systems.

Responder: Bryan J. Dougherty, Principal Structuring Analyst

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please provide the workpapers used to develop the updated rooftop load forecast in excel format with formulas intact, including the regression equations. Please include the following for both DEP and DEC by state:

17-3-1 Number of customers per year
17-3-2 Energy per year
17-3-3 Capacity per year

Response:

Please see the attached files identified as SACE_DR17-3_DECNC.xlsx, SACE_DR17-3_DECSC.xlsx, SACE_DR17-3_DEPNC.xlsx and SACE_DR17-3_DEPSC.xlsx.

SACE_DR17-3_DECNC.xlsx SACE_DR17-3_DECSC.xlsx SACE_DR17-3_DEPNC.xlsx SACE_DR17-3_DEPSC.xlsx

Responder: Bryan J. Dougherty, Principal Structuring Analyst

SACE DR17-3_DECNC

Year	Residential			Commercial			Industrial		
	Capacity (MWs)	Counts	Energy (MWhs)	Capacity (MWs)	Counts	Energy (MWhs)	Capacity (MWs)	Counts	Energy (MWhs)
2024	36.6	5,067	27,020	8.2	132	6,512	0.2	2	173
2025	75.4	10,446	79,129	17.0	274	19,113	0.4	4	469
2026	117.3	16,259	135,718	26.1	420	32,420	0.6	6	763
2027	156.5	21,691	191,927	35.0	564	45,671	0.8	8	1,056
2028	196.7	27,261	246,526	44.0	708	58,877	1.0	10	1,350
2029	238.6	33,080	302,313	53.0	854	71,797	1.2	12	1,638
2030	282.2	39,131	360,713	63.3	1,019	85,836	1.4	14	1,926
2031	327.5	45,414	421,194	73.7	1,187	100,949	1.6	16	2,213
2032	373.3	51,764	484,156	84.2	1,355	116,241	1.8	18	2,503
2033	416.1	57,698	542,829	93.9	1,511	130,707	2.0	20	2,783
2034	453.7	62,905	597,057	102.3	1,646	143,456	2.2	22	3,065
2035	474.4	65,766	634,474	106.9	1,720	152,393	2.4	24	3,347
2036	492.7	68,278	658,148	111.1	1,787	157,910	2.6	26	3,634
2037	512.0	70,926	679,591	115.6	1,859	163,412	2.8	28	3,905
2038	532.3	73,722	703,835	120.1	1,931	169,282	3.0	30	4,182
2039	553.5	76,650	729,376	124.6	2,003	175,124	3.2	32	4,458
2040	575.6	79,700	757,727	129.1	2,075	181,323	3.4	34	4,742
2041	598.9	82,907	783,953	134.5	2,162	187,161	3.6	36	5,005
2042	623.0	86,237	813,176	140.5	2,258	195,056	3.8	38	5,276
2043	648.1	89,696	843,498	146.5	2,354	203,009	4.0	40	5,546
2044	674.0	93,274	876,877	152.5	2,450	211,372	4.2	42	5,827
2045	700.9	96,998	907,479	158.5	2,546	218,793	4.4	44	6,083
2046	728.8	100,854	941,315	164.8	2,647	226,715	4.6	46	6,349
2047	757.6	104,828	976,235	171.5	2,755	235,443	4.8	48	6,613
2048	787.1	108,916	1,014,400	178.3	2,863	244,791	5.0	50	6,891
2049	817.6	113,135	1,049,045	185.0	2,971	253,049	5.2	52	7,139
2050	849.1	117,489	1,087,191	191.7	3,079	261,788	5.4	54	7,400

Notes:
Capacity and counts are presented as year end values and represent cumulative totals as of the end of each year (cumulative totals starting from January 2024)
Capacity data presented as nameplate
Energy data represents the estimated energy produced in each year

SACE DR17-3_DECSC

Year	Residential			Commercial			Industrial		
	Capacity (MWs)	Counts	Energy (MWhs)	Capacity (MWs)	Counts	Energy (MWhs)	Capacity (MWs)	Counts	Energy (MWhs)
2024	13.0	1,685	9,104	0.8	24	629	0.1	1	70
2025	26.6	3,439	26,813	1.7	48	1,804	0.2	2	200
2026	40.8	5,281	45,246	2.5	72	2,974	0.3	3	338
2027	55.4	7,177	64,325	3.4	96	4,138	0.4	4	476
2028	70.5	9,129	84,024	4.2	120	5,306	0.5	5	613
2029	86.0	11,138	103,884	5.2	150	6,510	0.6	6	748
2030	102.0	13,204	124,405	6.4	186	8,118	0.7	7	884
2031	118.3	15,317	145,364	7.6	222	9,762	0.8	8	1,018
2032	134.6	17,425	166,864	8.8	258	11,421	0.9	9	1,155
2033	149.8	19,403	186,790	9.8	286	12,910	1.0	10	1,286
2034	163.4	21,157	205,318	10.6	310	14,039	1.1	11	1,418
2035	171.5	22,211	218,634	11.5	334	15,148	1.2	12	1,550
2036	178.7	23,140	227,679	12.3	358	16,285	1.3	13	1,685
2037	186.0	24,096	235,740	13.1	382	17,349	1.4	14	1,812
2038	193.6	25,073	244,502	14.0	406	18,441	1.5	15	1,942
2039	201.2	26,067	253,422	14.8	430	19,527	1.6	16	2,072
2040	209.0	27,079	263,084	15.7	454	20,652	1.7	17	2,205
2041	217.0	28,115	271,733	16.5	478	21,684	1.8	18	2,329
2042	225.2	29,176	281,161	17.3	502	22,755	1.9	19	2,456
2043	233.6	30,258	290,794	18.2	526	23,820	2.0	20	2,583
2044	242.0	31,357	301,246	19.0	550	24,932	2.1	21	2,714
2045	250.7	32,478	310,506	19.9	574	25,934	2.2	22	2,834
2046	259.5	33,617	320,582	20.7	598	26,983	2.3	23	2,959
2047	268.4	34,774	330,814	21.5	622	28,027	2.4	24	3,083
2048	277.5	35,950	341,956	22.4	646	29,128	2.5	25	3,213
2049	286.7	37,149	351,719	23.2	670	30,100	2.6	26	3,330
2050	296.1	38,365	362,376	24.1	694	31,128	2.7	27	3,452

Notes:

Capacity and counts are presented as year end values and represent cumulative totals as of the end of each year (cumulative totals starting from January 2024)

Capacity data presented as nameplate

Energy data represents the estimated energy produced in each year

SACE DR17-3_DEPNC

Year	Residential			Commercial			Industrial		
	Capacity (MWs)	Counts	Energy (MWhs)	Capacity (MWs)	Counts	Energy (MWhs)	Capacity (MWs)	Counts	Energy (MWhs)
2024	33.4	4,448	24,809	3.4	96	2,652	0.2	2	173
2025	67.3	8,979	71,018	6.7	192	7,612	0.4	4	468
2026	103.0	13,734	119,284	10.1	288	12,549	0.6	6	762
2027	138.8	18,509	168,482	13.4	384	17,461	0.8	8	1,054
2028	175.9	23,459	218,741	17.2	492	22,727	1.0	10	1,347
2029	214.6	28,613	270,010	21.0	600	28,169	1.2	12	1,633
2030	254.5	33,935	323,421	24.8	708	33,629	1.4	14	1,921
2031	295.6	39,411	378,232	28.9	827	39,343	1.6	16	2,207
2032	337.1	44,951	435,029	33.1	947	45,465	1.8	18	2,496
2033	376.4	50,190	488,354	36.9	1,055	51,038	2.0	20	2,775
2034	411.5	54,873	538,281	40.5	1,156	56,324	2.2	22	3,057
2035	433.3	57,770	574,799	42.5	1,215	60,170	2.4	24	3,337
2036	452.9	60,392	600,518	44.6	1,275	62,886	2.6	26	3,623
2037	473.4	63,119	624,064	46.7	1,335	65,537	2.8	28	3,894
2038	494.6	65,953	649,946	48.8	1,395	68,309	3.0	30	4,170
2039	516.7	68,893	676,805	50.9	1,455	71,067	3.2	32	4,445
2040	539.5	71,939	706,225	53.0	1,515	73,969	3.4	34	4,728
2041	563.2	75,091	733,443	55.4	1,583	76,685	3.6	36	4,990
2042	587.6	78,349	763,211	57.9	1,655	80,007	3.8	38	5,261
2043	612.8	81,707	793,936	60.4	1,727	83,333	4.0	40	5,530
2044	638.5	85,132	827,208	63.0	1,799	86,826	4.2	42	5,810
2045	664.9	88,655	857,446	65.5	1,871	89,932	4.4	44	6,065
2046	692.1	92,283	890,480	68.0	1,943	93,208	4.6	46	6,330
2047	720.1	96,018	924,455	70.8	2,024	96,653	4.8	48	6,594
2048	748.9	99,858	961,524	73.8	2,108	100,726	5.0	50	6,871
2049	778.5	103,800	995,208	76.7	2,192	104,358	5.2	52	7,118
2050	808.5	107,798	1,031,709	79.7	2,276	108,187	5.4	54	7,378

Notes:

Capacity and counts are presented as year end values and represent cumulative totals as of the end of each year (cumulative totals starting from January 2024)

Capacity data presented as nameplate

Energy data represents the estimated energy produced in each year

SACE DR17-3_DEPSC

Year	Residential			Commercial			Industrial		
	Capacity (MWs)	Counts	Energy (MWhs)	Capacity (MWs)	Counts	Energy (MWhs)	Capacity (MWs)	Counts	Energy (MWhs)
2024	2.5	313	1,726	0.6	12	450	0.0	0	0
2025	5.1	637	5,076	1.2	24	1,295	0.1	1	69
2026	7.7	967	8,475	1.8	36	2,136	0.1	1	117
2027	10.4	1,303	11,957	2.4	48	2,973	0.2	2	197
2028	13.2	1,645	15,480	3.0	60	3,814	0.2	2	254
2029	15.9	1,993	19,022	3.6	72	4,635	0.3	3	333
2030	18.8	2,346	22,599	4.2	84	5,459	0.3	3	389
2031	21.6	2,706	26,258	4.8	96	6,280	0.4	4	468
2032	24.5	3,066	29,981	5.4	108	7,110	0.4	4	524
2033	27.3	3,410	33,483	6.0	120	7,908	0.5	5	601
2034	29.9	3,732	36,846	6.6	132	8,716	0.5	5	656
2035	31.9	3,983	39,658	7.2	144	9,520	0.6	6	733
2036	33.8	4,223	42,084	7.8	156	10,342	0.6	6	789
2037	35.7	4,463	44,304	8.4	168	11,116	0.7	7	863
2038	37.6	4,703	46,607	9.0	180	11,908	0.7	7	917
2039	39.5	4,943	48,898	9.6	192	12,697	0.8	8	993
2040	41.5	5,183	51,292	10.2	204	13,509	0.8	8	1,048
2041	43.4	5,427	53,452	10.8	216	14,261	0.9	9	1,121
2042	45.4	5,679	55,811	11.4	228	15,037	0.9	9	1,173
2043	47.4	5,931	58,183	12.0	240	15,810	1.0	10	1,247
2044	49.5	6,183	60,679	12.6	252	16,614	1.0	10	1,302
2045	51.5	6,435	62,891	13.2	264	17,343	1.1	11	1,372
2046	53.5	6,690	65,231	13.8	276	18,104	1.1	11	1,424
2047	55.6	6,954	67,650	14.4	288	18,862	1.2	12	1,496
2048	57.7	7,218	70,247	15.0	300	19,657	1.2	12	1,551
2049	59.9	7,482	72,516	15.6	312	20,365	1.3	13	1,619
2050	62.0	7,746	74,931	16.2	324	21,111	1.3	13	1,670

Notes:

Capacity and counts are presented as year end values and represent cumulative totals as of the end of each year (cumulative totals starting from January 2024)

Capacity data presented as nameplate

Energy data represents the estimated energy produced in each year

EXHIBIT JD-5 – Behind the Meter Analysis Methods
E-100, SUB 190

1. Acquire data on forecasted behind the meter solar from SACE DR 17-3.
2. Assume 2024 storage pair rate is 10%, consistent with the 2022 storage pair rate reported in the Direct Testimony of Duff and Byrd at page 37.
3. Scale the 2024 residential pair rate to 28% in the year 2028, based on forecast from the Solar Energy Industry Association.[1]
4. From 2028 on, assume linear scaling rate to achieve a residential 50% storage pairing rate to solar by 2040.
5. Assume a 2024 non-residential pairing rate of 7%, based on national data from the Lawrence Berkely National Laboratory (LBNL).[2]
6. Assume non-residential pairing rate scales proportionally to residential pairing rate. This produces a non-residential pairing rate of 19.6% in 2028 and 35% in 2040.
7. Combine the Commercial and Industrial solar forecast from SACE DR 17-3 into a non-residential category.
8. Determine incremental solar capacity added each year by category.
9. Calculate the number of residential solar customers at add storage each year by multiplying the incremental residential solar customer count with the solar pair rate.
10. I assume the average storage capacity size to be 8.5 kW, which is the weighted average of current residential storage customers according to LBNL.
11. Multiply incremental residential storage customer count by 8.5kW to find storage capacity additions per year.
12. Multiply incremental C&I solar capacity by the incremental pair rate to find the percent of C&I solar capacity adding storage each year.
13. Assume that C&I storage systems are sized at 75% the size of the associated solar installation, based on observed current trends by LBNL. Multiply each year's solar capacity that is assumed to be paired with storage by 0.75 to find the annual storage capacity additions.

[1] https://www.seia.org/solar-industry-research-data
[2] https://emp.lbl.gov/tracking-the-sun/

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please provide the following data in excel format with all formulas intact.

17-15-1 Historical and forecasted load growth from the years 2014 through the end of the study period.

17-15-2 Solar PV
- (a) Technology assumptions
  - i. Annual degradation factor described as %/year
  - ii. kW per square foot of usable space
- (b) Capital expenditure
  - i. Residential
  - ii. Non-residential
- (c) Operations and maintenance costs
  - i. Residential
  - ii. Non-residential

17-15-3 Battery storage
- (a) Technology assumptions
  - i. Type of batteries
  - ii. Efficiency rating
    - Residential
    - Commercial
    - Industrial
  - i. Battery lifetime
    - Residential
    - Commercial
    - Industrial
- (b) Capital expenditure
  - i. Residential
  - ii. Non-residential
- (c) Operations and maintenance costs
  - i. Residential

ii. Non-residential

17-15-4 Interruption cost per outage event
(a) Residential
(b) Small C&I
(c) Large C&I

17-15-5 Interruption cost per average kW
(a) Residential
(b) Small C&I
(c) Large C&I

17-15-6 Interruption cost per unserved kWh
(a) Residential
(b) Small C&I
(c) Large C&I

17-15-7 Value of resilience for each item in 17-15-**4**, 17-15-**5**, and 17-15-**6** (above), including the interruption duration hours

17-15-8 Electric vehicle load growth, by capacity and by energy, per year for the duration of the study.

17-15-9 Historical and forecasted impact of each individual EV load management program as described in Appendix H.

Response:

17-15-1: See attached SACE DR 17-15.xlsx for historical load growth and forecasted load growth in the attachment as requested.

SACE DR17-15.xlsx

Responder: Jeffrey A. Day, Principal Load Forecasting Analyst

17-15-2: Please see the attached file identified as SACE_DR17-15-2.xlsx.

SACE_DR17-15-2.xlsx

17-15-3: As noted in SACE DR17-12, the Company did not model behind the meter ("BTM") storage. Refer also to Appendix H in the Carolinas Resource Plan which notes a pilot program for BTM residential storage, but which is not included in the resource plan modeling. As a result, the requested data is not available.

Responder: Bryan J. Dougherty, Principal Structuring Analyst

17-15-4: Duke Energy uses the Interruption Cost Estimate (ICE) calculator tool, developed by Lawrence Berkeley National Laboratory and Nexant, Inc. and funded by the Department of Energy as its resource for valuing customer interruption costs. If the parties are interested in gathering estimated costs for interruption per outage event, per average kW, and per unserved kWh based on single year's SAIDI/SAIFI figures, the tool is available here: https://icecalculator.com/home.

See " SACE DR 17-15-4 NC_SC ICE Table Values.xlsx" for ICE values at various durations which Duke Energy uses in its distribution program cost benefit analyses.

SACE DR 17-15-4
NC_SC ICE Table Valu

17-15-5: See response to SACE DR 17-15-4.

17-15-6: See response to SACE DR 17-15-4.

17-15-7: Duke Energy has not adopted a quantitative methodology for the value of resilience. This is a common challenge across the industry.

Responder: Evan W. Shearer, Principal Integrated Planning Coordinator

17-15-8: Please see the attached document for load peak growth information for the duration of the study: "SACE DR17-15_EV Peaks.xlsx."

Please see the following attachments for jurisdictional energy growth information, per year, through the duration of the study.

"SACE DR17-15_DEC_NC.xlsx", "SACE DR17-15_DEC_SC.xlsx", "SACE DR17-15_DEPE_NC.xlsx", "SACE DR17-15_DEPE_SC.xlsx", and "SACE DR17-15_DEPW_NC.xlsx"

Responder: Bryan M. Wright, Lead Structuring Analyst

17-15-9: Off Peak Credit:

The analysis reflecting the impact of the South Carolina Off-Peak Credit pilot program is provided in Figure H-17 in Appendix H of the Plan. That initial analysis was performed by the program implementation vendor and demonstrates that the pilot program has caused the average on-peak charging demand of program participants to reduce from approximately 0.17 kW before enrollment to less than 0.04 kW after enrollment. Generally, the Companies believe that future iterations of similar programs across the Carolinas would likely yield similar results. Since the Off-Peak Credit has not been expanded yet, forecasts of future impacts have not yet been performed and hence are not reflected in the CPIRP.

Responder: Tim Duff, GM. Customer Solutions Regulatory Enablement

Duke response to SACE DR 17-15

DEC Retail - Historical Load Growth

Year	Weather Normalized Actuals	IRP Retail Forecast
2014	78,032	77,283
2015	77,807	78,150
2016	78,302	78,925
2017	78,129	78,714
2018	79,678	78,124
2019	78,894	79,262
2020	76,761	80,618
2021	79,325	79,098
2022	81,089	79,434
2023	79,759	79,945
Avg. Annual Growth Rate	0.2%	0.4%

DEP Retail - Historical Load Growth

Year	Weather Normalized Actuals	IRP Retail Forecast
2014	43,458	43,744
2015	43,420	43,537
2016	43,753	43,937
2017	43,446	43,749
2018	44,213	44,306
2019	43,765	44,065
2020	42,963	44,484
2021	43,664	44,077
2022	44,684	44,061
2023	42,944	44,787
Avg. Annual Growth Rate	-0.1%	0.3%

DEC IRP - Forecasted Retail Load

Year	IRP Retail Forecast
2024	81,215
2025	82,537
2026	84,218
2027	88,458
2028	91,352
2029	94,255
2030	98,336
2031	101,389
2032	102,669
2033	105,236
2034	106,617
2035	108,283
2036	109,999
2037	111,659
2038	113,390
Avg. Annual Growth Rate	2.4%

DEP IRP - Forecasted Retail Load

Year	IRP Retail Forecast
2024	44,500
2025	45,433
2026	46,921
2027	48,768
2028	50,588
2029	52,534
2030	53,858
2031	54,398
2032	55,180
2033	55,841
2034	56,508
2035	57,331
2036	58,216
2037	58,994
2038	59,793
Avg. Annual Growth Rate	2.1%

SACE DR17-15-2

Solar System Costs/Data	Residential						Non-Residential					
	NC			SC			NC			SC		
	Solar Price ($/W-AC)	Annual O&M ($/kW-AC-year)	Annual Solar Degradation	Solar Price ($/W-AC)	Annual O&M ($/kW-AC-year)	Annual Solar Degradation	Solar Price ($/W-AC)	Annual O&M ($/kW-AC-year)	Annual Solar Degradation	Solar Price ($/W-AC)	Annual O&M ($/kW-AC-year)	Annual Solar Degradation
2024	$2.75	$30.00	0.5%	$2.74	$30.00	0.5%	$1.81	$20.00	0.5%	$1.82	$20.00	0.5%
2025	$2.72	$30.00	0.5%	$2.72	$30.00	0.5%	$1.78	$20.00	0.5%	$1.78	$20.00	0.5%
2026	$2.66	$30.00	0.5%	$2.65	$30.00	0.5%	$1.72	$20.00	0.5%	$1.72	$20.00	0.5%
2027	$2.63	$30.00	0.5%	$2.63	$30.00	0.5%	$1.69	$20.00	0.5%	$1.69	$20.00	0.5%
2028	$2.59	$30.00	0.5%	$2.59	$30.00	0.5%	$1.65	$20.00	0.5%	$1.65	$20.00	0.5%
2029	$2.55	$30.00	0.5%	$2.55	$30.00	0.5%	$1.61	$20.00	0.5%	$1.61	$20.00	0.5%
2030	$2.53	$30.00	0.5%	$2.53	$30.00	0.5%	$1.58	$20.00	0.5%	$1.59	$20.00	0.5%
2031	$2.50	$30.00	0.5%	$2.50	$30.00	0.5%	$1.55	$20.00	0.5%	$1.56	$20.00	0.5%
2032	$2.47	$30.00	0.5%	$2.47	$30.00	0.5%	$1.52	$20.00	0.5%	$1.53	$20.00	0.5%
2033	$2.47	$30.00	0.5%	$2.47	$30.00	0.5%	$1.52	$20.00	0.5%	$1.53	$20.00	0.5%
2034	$2.47	$30.00	0.5%	$2.47	$30.00	0.5%	$1.52	$20.00	0.5%	$1.53	$20.00	0.5%
2035	$2.47	$30.00	0.5%	$2.47	$30.00	0.5%	$1.52	$20.00	0.5%	$1.53	$20.00	0.5%
2036	$2.47	$30.00	0.5%	$2.47	$30.00	0.5%	$1.52	$20.00	0.5%	$1.53	$20.00	0.5%
2037	$2.47	$30.00	0.5%	$2.47	$30.00	0.5%	$1.52	$20.00	0.5%	$1.53	$20.00	0.5%
2038	$2.47	$30.00	0.5%	$2.47	$30.00	0.5%	$1.52	$20.00	0.5%	$1.53	$20.00	0.5%
2039	$2.47	$30.00	0.5%	$2.47	$30.00	0.5%	$1.52	$20.00	0.5%	$1.53	$20.00	0.5%

Notes:

Residential costs applicable to payback models used for BTM/NEM projections

Commercial cost data presented for informational purposes - as noted in the response to SACE DR17-1, the commercial forecasts are derived from the residential forecasts and commercial payback models are not used

Duke response to SACE DR 17-15-4

Regulated Utility	**DEC & DEP**
State:	**North Carolina**
ICE Calculated Value Year	**2016**

Table 1 - DEC & DEP (NC)
Estimated Interruption Cost per Event, Average kW and Unserved kWh by Duration and Customer Class (2016$)

Interruption Cost		Interruption Duration					
		Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
SAIFI	Model Input	1.00	1.00	1.00	1.00	1.00	1.00
SAIDI	Model Input	1.00	30.00	60.00	240.00	480.00	960.00
Medium and Large C&I (Over 50,000 Annual kWh)							
	Cost per Event	6,024.22	7,109.04	8,362.65	18,779.13	38,775.41	65,811.90
	Cost per Average kW	29.08	34.31	40.36	90.64	187.16	317.66
	Cost per Unserved kWh	1,744.63	68.63	40.36	22.66	23.39	19.85
Small C&I (Under 50,000 Annual kWh)							
	Cost per Event	462.55	578.42	718.94	2,059.69	5,032.91	9,574.95
	Cost per Average kW	151.19	189.07	235.00	673.24	1,645.09	3,129.72
	Cost per Unserved kWh	9,071.45	378.13	235.00	168.31	205.64	195.61
Residential							
	Cost per Event	5.21	5.76	6.35	10.68	18.06	32.87
	Cost per Average kW	3.51	3.88	4.28	7.20	12.17	22.15
	Cost per Unserved kWh	210.78	7.76	4.28	1.80	1.52	1.38

Regulated Utility	**DEC & DEP**
State:	**South Carolina**
ICE Calculated Value Year	**2016**

Table 1 - DEC & DEP (SC)

Estimated Interruption Cost per Event, Average kW and Unserved kWh by Duration and Customer Class (2016$)

Interruption Cost		**Interruption Duration**					
		Momentary	**30 Minutes**	**1 Hour**	**4 Hours**	**8 Hours**	**16 Hours**
SAIFI	Model Input	1.00	1.00	1.00	1.00	1.00	1.00
SAIDI	Model Input	1.00	30.00	60.00	240.00	480.00	960.00
Medium and Large C&I (Over 50,000 Annual kWh)							
	Cost per Event	5,484.61	6,466.71	7,601.67	17,042.93	35,229.36	60,064.42
	Cost per Average kW	20.66	24.36	28.63	64.19	132.69	226.23
	Cost per Unserved kWh	1,239.45	48.71	28.63	16.05	16.59	14.14
Small C&I (Under 50,000 Annual kWh)							
	Cost per Event	486.28	606.71	752.42	2,132.51	5,166.63	9,780.98
	Cost per Average kW	119.32	148.87	184.63	523.27	1,267.78	2,400.04
	Cost per Unserved kWh	7,159.35	297.75	184.63	130.82	158.47	150.00
Residential							
	Cost per Event	5.38	5.94	6.56	11.00	18.58	33.76
	Cost per Average kW	3.30	3.64	4.02	6.74	11.38	20.68
	Cost per Unserved kWh	197.82	7.28	4.02	1.68	1.42	1.29

EXHIBIT JD-7 – Managed Electric Vehicle Charging Analysis Methods
E-100, SUB 190

1. Start with EV projections from PS DR 3-16.
2. Combine DEC and DEP Winter and Summer peaks respectively.
3. Find 40% of Winter and Summer peak by year to find the peak load of EV customers participating in EV managed charging programs. The 40% assumption is taken from the Brattle Virtual Power Plant report.[1]
4. Multiply the peak demand of participating EV customers by (0.04/0.17) – which is the ratio of peak demand reductions found to have occurred in customers that participated in the South Carolina pilot referenced in SACE DR 17-15. This produces the peak demand of participating customers after program participation.
5. Subtract post-participation peak from pre-participation peak to find the total reduction due to the program.
6. Subtract total EV Peak from the reduction due to program to find total system EV peak when 40% of EV customers participate in a managed charging program.

[1] https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power-Technical-Appendix_5.3.2023.pdf

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please provide any electric vehicle-related adjustments by customer class to DEC's and DEP's peak demand and energy sales forecasts through 2038 and through 2050.

Response:

See attached PSDR 3-16.xlsx for class level and system peak demand EV projections as requested.

PSDR3-16.xlsx

Responder: Jeff Day, Principal Load Forecasting Analyst

16. **Please provide any electric vehicle-related adjustments by customer class to DEC’s and DEP’s peak demand and energy sales forecasts through 2038 and through 2050.**

	DEC EV - CPIRP Projections (MWHs, MWs)						DEP EV - CPIRP Projections (MWHs, MWs)					
Year	**Residential**	**Commercial**	**Industrial**	**DEC Total**	**Winter Peak**	**Summer Peak**	**Residential**	**Commercial**	**Industrial**	**DEC Total**	**Winter Peak**	**Summer Peak**
2024	69,295	23,484	3,135	95,914	3	18	45,125	13,781	1,762	60,668	1	6
2025	143,401	51,071	6,974	201,446	6	35	93,330	29,885	3,915	127,130	3	18
2026	251,131	93,408	13,006	357,545	12	61	162,825	54,793	7,357	224,975	6	30
2027	407,019	155,156	21,846	584,021	20	98	262,457	91,445	12,477	366,379	10	48
2028	629,360	239,119	33,662	902,141	32	150	403,091	141,657	19,403	564,150	16	90
2029	930,617	340,761	47,273	1,318,651	60	219	591,300	202,741	27,448	821,488	25	106
2030	1,324,096	459,005	62,158	1,845,259	89	306	834,390	273,907	36,288	1,144,585	37	116
2031	1,806,373	590,635	77,757	2,474,765	127	411	1,129,376	353,193	45,601	1,528,169	53	199
2032	2,374,193	737,990	94,604	3,206,787	173	531	1,473,538	441,780	55,682	1,971,000	73	257
2033	2,981,126	891,165	111,755	3,984,046	228	660	1,838,038	533,653	65,971	2,437,663	97	317
2034	3,625,717	1,053,684	129,942	4,809,344	288	793	2,222,538	630,908	76,895	2,930,340	123	380
2035	4,293,100	1,222,667	148,922	5,664,690	354	1,095	2,617,761	731,776	88,306	3,437,842	152	442
2036	4,976,631	1,399,449	169,107	6,545,187	424	1,249	3,020,804	837,149	100,447	3,958,400	183	503
2037	5,621,169	1,570,374	188,994	7,380,537	497	1,397	3,399,270	938,958	112,424	4,450,652	215	561
2038	6,264,844	1,746,604	209,967	8,221,415	572	1,537	3,776,623	1,043,905	125,058	4,945,586	248	616
2039	6,894,073	1,923,929	231,485	9,049,488	649	1,670	4,144,731	1,149,480	138,025	5,432,236	282	668
2040	7,529,081	2,107,976	254,225	9,891,282	728	1,795	4,515,938	1,259,060	151,729	5,926,728	316	811
2041	8,144,810	2,280,186	274,979	10,699,975	574	1,968	4,885,166	1,361,905	164,115	6,411,186	343	880
2042	8,837,118	2,474,002	298,352	11,609,473	622	2,113	5,300,405	1,477,666	178,065	6,956,136	372	955
2043	9,588,273	2,684,293	323,712	12,596,278	675	2,293	5,750,939	1,603,268	193,201	7,547,408	257	1,036
2044	10,432,780	2,921,308	352,342	13,706,430	733	2,514	6,257,539	1,744,839	210,288	8,212,666	279	1,124
2045	11,287,555	3,160,016	381,082	14,828,654	3,153	2,699	6,770,149	1,887,407	227,441	8,884,997	476	1,406
2046	12,246,997	3,428,618	413,474	16,089,089	2,840	2,929	7,345,612	2,047,837	246,773	9,640,222	516	1,381
2047	13,287,992	3,720,050	448,620	17,456,662	3,081	3,212	7,969,989	2,221,903	267,749	10,459,641	560	1,498
2048	14,458,359	4,048,519	488,296	18,995,175	3,343	3,485	8,672,065	2,418,101	291,429	11,381,595	607	1,699
2049	15,646,432	4,380,379	528,257	20,555,068	4,369	3,781	9,384,564	2,616,303	315,279	12,316,146	659	1,763
2050	16,976,379	4,752,711	573,159	22,302,249	4,741	4,102	10,182,252	2,838,689	342,078	13,363,018	745	1,913

Note: DEC Winter Peaks shift to the evening hours in 2045-2050, driven by the impacts of EV charging

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Regarding the implementation of time-of-use ("TOU") rates for North Carolina EV adopters, please:

17-7-1 Provide a description of the methodology the Companies used to analyze the TOU rates.

17-7-2 What percentage of NC EV owners did the Companies assume would be on TOU rates each year of the base planning period and the carbon neutrality planning horizon?

17-7-3 Please provide all workpapers associated with TOU rate impact analysis on EV adoption in NC.

17-7-4 Please provide a comparison of the load and energy impact of an EV owner under the TOU rate compared to the rate structure(s) used in the initial Resource Plan for each year of the planning horizon. Please provide this comparison in excel format with formulas intact.

Response:

17-7-1: The methodology for TOU rate implementation used forecasted TOU adoption of EV owners using the Guidehouse VAST tool which bases the charge profile characteristics from Guidehouse's collected database of public (such as NREL's Electric Vehicle Infrastructure - Projection ("EVI-Pro") tool) and private load profiles across charging use cases, from residential to different types of commercial and industrial customers. VAST models EV owners' responsiveness to pricing signals in TOU rates to shift the load over the course of the day to minimize electricity bills.

17-7-2: In the Guidehouse VAST model, the TOU rates are assigned at a charger level not a vehicle level. This is because one vehicle can use many different types of chargers, so profiles are developed based on the average charger profile. For LDV usecases the assumption for charger types for NC is ~60% adoption of a TOU rate for residential single unit dwelling, ~20% adoption for multi-unit dwelling, and ~10% adoption for workplace and public charging. For MDV and HDV, it varies per charger type with medium-heavy duty depots ~60%-70% adoption and bus depots 25% - 50% adoption. These numbers are based on internal estimates of potential adoption and will continue to be refined.

17-7-3: TOU rate implementation is not expected to impact the EV adoption in NC.

17-7-4: TOU impacts are not expected to impact the energy requirement under any circumstance. It still requires the same amount of energy to charge; the energy is just shifted in time.

The impacts of TOU implementation cannot be directly compared to the initially filed Resource Plan because more variables were changed than just TOU rates being implemented. Refreshed variables contributed to more vehicles being adopted, energy per vehicle going down slightly, and a net overall result of less than 5% increase in net new energy.

For the updated Fall 2023 EV forecast VAST produced a non-TOU output ("BAU") that was not used but had all customers on a flat rate structure. When comparing the BAU forecast to the TOU forecast it showed an average reduction of ~15% to the winter and summer peaks by implementing TOU rates, with a bigger impact in terms of MW to the summer peak. See attached file "SACE DR17-7_BAU_vs_TOU Comparison.xlsx".

SACE
DR17-7_BAU_vs_TOU

Responder: Bryan M. Wright, Lead Structuring Analyst

Winter Peak																
BAU	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Duke Energy Carolinas_NC	3.67	8.78	21.00	35.89	55.98	82.87	116.54	157.33	204.20	253.24	305.23	360.36	417.56	475.68	532.91	588.45
Duke Energy Progress	2.79	6.72	12.92	22.33	35.11	52.35	74.09	100.60	131.23	163.44	197.74	234.29	272.39	311.27	349.67	387.06
Total	6.46	15.50	33.92	58.22	91.09	135.22	190.63	257.93	335.43	416.68	502.97	594.65	689.96	786.95	882.58	975.50
TOU	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Duke Energy Carolinas	2.99	7.17	17.05	29.41	46.24	68.98	97.71	132.87	173.61	216.56	262.46	311.60	363.09	415.89	468.30	519.58
Duke Energy Progress	2.27	5.47	10.58	18.41	29.15	43.80	62.46	85.43	112.23	140.61	171.08	203.84	238.33	273.81	309.12	343.74
Total	5.26	12.64	27.63	47.82	75.39	112.78	160.17	218.30	285.84	357.17	433.54	515.43	601.42	689.70	777.42	863.32
Winter Peak Reduction	19%	18%	19%	18%	17%	17%	16%	15%	15%	14%	14%	13%	13%	12%	12%	12%

Summer Peak																
BAU	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Duke Energy Carolinas	22.66	46.28	80.85	127.34	186.13	257.60	340.53	432.77	528.21	623.01	925.63	1042.97	1155.54	1263.53	1365.94	1459.82
Duke Energy Progress	18.05	36.77	64.06	121.28	146.56	160.10	266.48	337.69	411.01	483.45	554.30	622.31	687.42	750.00	809.42	863.29
Total	40.71	83.05	144.91	248.62	332.70	417.70	607.00	770.46	939.22	1106.45	1479.93	1665.28	1842.96	2013.53	2175.36	2323.11
TOU	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Duke Energy Carolinas	20.24	40.77	70.82	111.26	162.43	224.66	296.92	377.35	460.65	543.52	631.13	714.52	796.01	875.99	953.90	1027.51
Duke Energy Progress	16.15	32.45	56.21	106.88	128.09	132.19	232.62	294.72	358.70	421.99	484.00	543.63	600.81	655.88	708.36	756.25
Total	36.39	73.21	127.03	218.13	290.52	356.85	529.54	672.07	819.35	965.51	1115.13	1258.15	1396.81	1531.87	1662.25	1783.76
Summer Peak Reduction	11%	12%	12%	12%	13%	15%	13%	13%	13%	13%	25%	24%	24%	24%	24%	23%

Notes:

*Showing NC impacts only

*Load Forecast peak hour might shift depending on BAU vs TOU impacts. Using same peak hour for both

*Energy is unchanged and remains the same.

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please provide the bulk system benefits attributed to batteries, solar, energy efficiency, demand response, and any other distributed energy resources for which the Companies have established bulk system benefits, as described on page 3 of Appendix G. Please describe how the Companies developed these values.

Response:

The battery energy storage system proxy value process has been described in past ISOP stakeholder events and can be summarized as follows: The ISOP team performs multiple, sequential Encompass model runs to reflect the value provided by a 200 MW storage resource of a given duration that can offer energy arbitrage; then energy and regulation; then energy, regulation and contingency; and finally, energy, regulation, contingency, and balancing. This is performed sequentially to ensure there is no double-counting of services provided. The bulk system proxy values, for capacity and energy in addition to ancillary services, are applied to individual projects by the ISOP team based on the size, duration, and other technical details of a storage project. This allows the Company to assign a value of ancillary services at various durations to smaller resources (e.g. 1 -10 MW) proportionally from those calculated for larger (i.e. 200 MW) resources. This is necessary because the value of small resources may not register clearly in a production cost model at the full IRP scale.

Responder: Michael F. Jacob, Manager DSM Analytics