BEFORE
THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1276

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF JONATHAN L. BYRD FOR DUKE ENERGY CAROLINAS, LLC**
Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation	))))	

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jonathan L. Byrd, and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Managing Director of Rate Design and Regulatory Solutions for Duke Energy Business Services, LLC ("DEBS"). DEBS is a service company subsidiary of Duke Energy Corporation ("Duke Energy") that provides services to Duke Energy and its subsidiaries, including Duke Energy Carolinas, LLC ("DEC" or the "Company") and its affiliated utility operating companies.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF RATE DESIGN AND REGULATORY SOLUTIONS?

A. My responsibilities include creating new pricing designs across all Duke Energy jurisdictions as well as implementing rate tariffs, administration and filings, and contracts, including interactions with stakeholders and seeking necessary regulatory approvals.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of North Carolina ("UNC") at Charlotte, a Master of Engineering degree from North Carolina State University, and a Master of Business Administration degree from UNC-Chapel Hill.

I joined Duke Energy in 2005 and have worked in various roles providing products and services to large business customers, corporate finance, and renewable energy. In June of 2020, I moved into my current role in Pricing and Regulatory Solutions.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have appeared before the Commission on several occasions, most recently in the Company's petition for issuance of storm cost recovery financing orders in Docket No. E-7, Sub 1243.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am proposing several new customer-centric and innovative rate designs and pricing changes to address emerging trends impacting North Carolina today. I am also proposing to simplify and modernize these designs to assist in the harmonization between the Company and Duke Energy Progress, LLC ("DEP").

Q. PLEASE DESCRIBE THE EXHIBITS ATTACHED TO YOUR TESTIMONY.

A. The exhibits to my testimony are as follows:

- Byrd Exhibit 1 is a chart showing a visual comparison between the Company's current Time-of-Use ("TOU") periods and the Company's proposed new TOU periods;

- Byrd Exhibit 2 is a figure showing TOU period alignment with recent marginal energy costs (average from 2018-2020);
- Byrd Exhibits 3-5 are figures showing TOU period alignment with the Cost Duration Model ("CDM") output for the years 2021, 2026, and 2030, respectively;
- Byrd Exhibit 6 is a figure showing TOU period alignment with 2024 Loss of Load Expectation ("LOLE") times;
- Byrd Exhibit 7 contains tariff sheets for the Company's proposed redesigned Hourly Pricing Schedule (Schedule HP), new High Load Factor Schedule (Schedule HLF), new Economic Development Rider (Rider ED), and new Non-Residential Solar Choice Rider (Rider NSC).

Q. WERE BYRD EXHIBITS 1 – 7 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes. They were.

Q. WOULD YOU SUMMARIZE THE MORE SIGNIFICANT EMERGING ENERGY TRENDS IMPACTING NORTH CAROLINA TODAY THAT CALL FOR RATE DESIGN CHANGES OR REVISIONS?

A. Yes. North Carolina, like many other states, is facing several broad energy trends which create both challenges and opportunities, especially in the realm of rate design. Meter technology advances enable more sophisticated rate designs which can provide both improved price signals and improved alignment between customer charges and usage behaviors impacting cost of service. Similarly, end-use technology advancements are enabling monitoring and control of energy loads such that customers can act upon more sophisticated price signals with load management. The expansion of solar generation in DEC's service territory, which is expected to continue, is reshaping net peak demand. Rate design and pricing must adapt to reflect the impacts such shifts are driving in resource planning and system management. Finally, anticipated growth of technology with unique or controllable load characteristics, such as electric vehicles ("EV"), present opportunities for customers and must be considered in modern rate designs. The Company is proposing rate design changes to accommodate and anticipate these trends, while maintaining or improving alignment between cost of service and proposed target revenues for each rate class.

Q. PLEASE DESCRIBE THE PROCESS THE COMPANY USED TO DEVELOP THESE NEW RATE DESIGNS.

A. As ordered by the Commission in Docket No. E-7, Sub 1214, the Company engaged a third-party facilitator to lead a year-long Comprehensive Rate Design Study ("CRDS") with external stakeholders to develop an informed vision and direction for the Company's future pricing and rate design options. The study process included broad participation from very engaged organizations, relied upon stakeholder feedback and presentations to guide and prioritize the study scope, and yielded possibilities for constructive rate design changes that balance priorities and desires of the participating organizations. Participation included more than 50 organizations including commercial and industrial customers, EV companies and advocates, environmental advocates, government agencies, public advocates, renewable/distributed energy resource companies, and legal/consulting companies. Importantly, the scope included shifting grid dynamics, incorporation of distributed energy technologies, and recognition of varying customer expectations across all major tariffs and riders. Quarterly updates on the study and the associated roadmap were filed with the Commission in Docket No. E-7, Sub 1214. As I will discuss later in my testimony, the Company is proposing several modifications to rate designs to directly incorporate changes based on requests and input from stakeholders during the CRDS, and DEC's modernized rate designs broadly reflect findings and conclusions from that collaborative process.

Q. PLEASE SUMMARIZE THE MORE SIGNIFICANT RATE DESIGN CHANGES OR REVISIONS THE COMPANY IS PROPOSING TO MAKE TO ITS TARIFFS IN THIS PROCEEDING.

A. As with any rate case, the Company's rates have been revised to produce the target class and total revenue requirements being sought in this proceeding, as described in the testimony of Witness Morgan Beveridge. However, the Company is also proposing a series of design changes to protect customers from cross-subsidizations, send price signals that encourage system beneficial consumption behaviors, and generally modernize the Company's pricing structure.

Most significantly, the Company is proposing updated and aligned TOU periods across the Company's tariffs that contain time-differentiated pricing, including both residential (Rate RT) and non-residential customers (Rate OPT-

V). Consistent with the time period updates, the Company must necessarily modify demand charge structures to align with the new periods. Together, these changes improve price and cost causation alignment, allow for simplification elsewhere in the rate designs, and offer greater opportunity for load management activities to help customers control energy costs and simultaneously create benefits for the broader system. Complementing these changes, the Company will refresh seasonal pricing elements to reflect the current system and for simplification.

The Company is also proposing new or redesigned tariffs to expand rate options for customers, including:

- Redesigned Hourly Pricing Tariff;
- New High Load Factor ("HLF") Tariff;
- New Non-Residential Solar Choice; and
- New Economic Development Rider.

I will describe the basis and rationale for the new TOU periods and demand charge structures, how these new structures are allowing for changes and simplification to other charges and policies, as well as the benefits of the new tariffs mentioned above. Witness Beveridge will provide further details on the specific pricing and design elements of the existing and new or redesigned tariffs.

II. <u>TOU PERIOD CHANGES</u>

Q. WHAT CHANGES ARE YOU PROPOSING TO THE TOU PERIODS?

A. The Company proposes to refresh TOU periods as follows (peak periods do not include weekends or holidays):

- On-Peak (Summer) – 6:00 PM – 9:00 PM
- On-Peak (Non-Summer) – 6:00 AM – 9:00 AM
- Discount (Summer) – 1:00 AM – 6:00 AM
- Discount (Non-Summer) – 1:00 AM – 3:00 AM and 11:00 AM – 4:00 PM
- Summer consists of the months May – September
- Non-Summer consists of the months October – April

A chart showing a visual comparison of the existing TOU time periods and the Company's proposed TOU time periods is attached to my testimony as Byrd Exhibit 1.

Q. WHAT IS THE BASIS FOR THE PROPOSED TOU CHANGES?

A. Broadly, TOU energy rates can include a wide variety of pricing and design options but generally seek to align price signals to the cost differences that exist across time (days, seasons, hours) for the electricity grid. Grid operations require that supply must match demand at any given point in time; thus, supply resources are called upon based on the level of system demand, which can vary greatly across days and seasons. Increasingly, intermittent and non-dispatchable supply resources (e.g., solar) are complicating the supply/demand relationship, calling for changes in operational capabilities for the other supply resources and also for demand. Proper rate design seeks not only to recover the costs of providing service to customers based on their use of the system, but also to provide price signals so that customers who are able to respond to price signals can do so in an informed and system beneficial manner. TOU pricing with properly defined periods is necessary to ensure proper price signaling. The Company's existing TOU periods, established decades ago, are no longer appropriate and increasingly do not align with the Company's current and anticipated system needs. Furthermore, the desire for modernized TOU periods comes from the evolving needs of the electric system and its ability to provide superior price signals, which can enable cost-effective customer adoption of new technologies, such as smart energy management devices, energy storage, and EVs.

The TOU periods proposed were discussed and evaluated at length with stakeholders during the CRDS and have already been approved by the Commission for three of the Company's current tariffs: RSTC, RETC, and SGSTC. These rates were approved in Docket No. E-7, Sub 1253 and became effective October 1, 2021.

Q. HOW DID THE COMPANY DETERMINE THE DURATION AND PRICING FOR THE NEW TOU PERIODS?

A. The Company took a forward-looking approach in designing the new TOU periods discussed above, considering both current conditions and expected system evolution over the next decade. Multiple perspectives and goals were considered in crafting periods that: (1) better reflect cost causation and the growing impact of solar generation; (2) accommodate changing consumption patterns caused by distributed energy technologies such as EV charging, energy storage, rooftop solar, and other distributed energy technologies; and (3) facilitate customer modification of energy consumption patterns to create bill savings.

The Company analyzed projected load patterns and costs to develop refreshed TOU periods. Historic and forecasted costs were analyzed through five different lenses: gross load, net load after utility-scale solar, retail load, marginal energy cost, and LOLE. Gross load, net load, retail load, and marginal energy cost were examined using the CDM, which importantly was also used to set the prices for the original approval of the Company's Critical Peak Pricing rates for both Small General Service (Schedule SGSTC) and Residential Service (Schedules RSTC and RETC) customers. The revisions to TOU periods that the Company is proposing in this case are taken directly from observations of the CDM, which can be seen in Byrd Exhibits 2-6.

In support of the petition for approval of the aforementioned Critical Peak Pricing Rates, the Company produced a Technical Document outlining the approach for establishing the TOU periods which the Company now proposes to broadly implement across its portfolio of rates. The Technical Document was filed in Docket No. E-2, Sub 1280 on September 30, 2021.

Q. CAN YOU PLEASE EXPLAIN THE CDM?

A. The CDM provides improved linkage between recovery of system costs (e.g., tariff pricing) and the time periods during which system assets are being utilized. For all three major utility functions (generation, transmission, and distribution), some assets are only used to meet demand during a small number of peak hours, while other assets are used for all or nearly all hours. The CDM allocates costs for assets across all three functions based on anticipated utilization. Costs for assets used during all hours are assigned accordingly, while cost for assets used only during peaking hours are concentrated in those hours (e.g., early winter morning hours).

As generation, transmission, and distribution demands are not perfectly coincident, costs for each function were distributed independently, using specific load duration curves. Generation costs were allocated using net peak load duration (gross load net of utility-scale solar), transmission capacity costs were allocated using gross system load duration, and distribution capacity costs were allocated using a distribution load duration curve for the customer class for which rates are being designed (e.g., residential load duration curve for residential customers). The following five steps outline the cost allocation process across all hours, for each function, using its respective load duration curve.

<u>Step 1</u>: Capacity costs were divided by the peak load of each load duration curve to find a unit cost per megawatt ("MW") of capacity.

<u>Step 2</u>: The incremental load in each hour was calculated by taking the difference in load between that hour and the hour with the next highest load. For the lowest load hour of the year, the load in that hour is used. Note that the sum of all these incremental load amounts is necessarily equal to the peak load.

<u>Step 3</u>: For each hour, the incremental load was shared evenly between the hour in question and all hours of the year that have a higher load

than the hour in question. The incremental load at the highest load hour was not shared as there are no higher load hours. The incremental load at the second highest hour was shared evenly between the top two hours, and so forth.

Step 4: Next, the load allocated to each hour was totaled. The highest load hour has a share of load for all hours of the year, the second highest load hour has a share of load for all hours of the year except the highest hour, and so forth.

Step 5: Finally, the load allocated to each hour in Step 4 was multiplied by the unit cost calculated in Step 1 to calculate the total cost of each hour. This can in turn be divided by the billing load in that hour to calculate the unit cost of each hour.

Combining the results of the CDM for each customer class with hourly energy costs provides the variable cost of serving the respective customer class in each hour of the year. In combination with the TOU periods described above, prices for each TOU period (e.g., On-Peak) can be established to recover those costs for each respective period. Prices may be slightly modified to ensure estimated revenue is as close as possible to, but not exceeding, the revenue requirement.

Q. WHAT WERE THE RESULTS OF THE COST DURATION MODEL?

A. Byrd Exhibits 2-6 show that the CDM is in alignment with historical marginal energy costs. Because capacity constrained hours will also have high marginal energy costs (when the utility is at the high end of its economic dispatch curve), this shows good alignment on capacity costs as well. The impact of additional solar energy added between 2021 and 2030 is clearly reflected in the summer afternoon peak being pushed further back into hours with less sunlight. For the same reason, the Non-Summer mid-day Discount periods exhibit even lower costs, as these times of high solar generation and relatively low load lead to "duck-curve" situations where solar curtailment could become necessary. As a result, the Company is proposing a Discount period during such hours to better reflect lower cost of service. Also, the April load shape more closely aligns with the Non-Summer period than the Summer period. Finally, the LOLE chart shows that the highest capacity cost hours are in winter mornings and relatively little of the LOLE is not covered by peak time periods, underscoring the appropriateness of the proposed periods.

As reflected in Byrd Exhibit 1, the Company's historic TOU periods vary significantly and do not reflect current system costs and operational realities reflected in the CDM analysis. Continued use of the existing periods would result in customers receiving high price signals that discourage consumption when the system in fact has an abundance of solar energy, thus increasing the likelihood of solar curtailment. Conversely, the historic periods have off-peak hours that are increasingly times of system peaks, notably late afternoon hours during the summer. Thus, customer responsiveness to the existing periods and price signals may exacerbate the evening summer peak and increase costs to all customers.

Additionally, the historic on-peak periods present challenges for customers seeking to respond to prices, whether through advanced energy management controls or with distributed energy technologies such as storage. Byrd Exhibit 1 shows that some existing on-peak periods are up to 12 hours in length, compared to the three-hour window for the proposed TOU periods that reflect current system realities. The new, shorter window creates more opportunities for customers to manage usage patterns or utilize distributed energy storage to reduce their electricity bills.

The modernized periods, shown in Byrd Exhibit 1, provide consistent Discount periods for owners with flexible loads (e.g., EVs, whether Residential or Fleet), during the overnight hours from 1:00 AM – 3:00 AM (for both Summer and Non-Summer), extending to 6:00 AM in the Summer. The Discount charging periods provide an important foundation to all customers with such flexible loads.

Importantly, the Company considered rate stability (including TOU period definitions) in developing the proposed times with the goal of avoiding further changes for several years. Frequent changes to TOU periods are inadvisable and potentially burdensome as customers use price periods to evaluate energy investments and program load management devices (e.g., thermostats, EV chargers). Accordingly, the Company has relied upon net peak forecasts stretching close to a decade beyond the current period for the development of the new TOU periods. The Company proposes using these TOU periods for all TOU rates, residential and non-residential, except for Schedule PG which the Company proposes to close to new customers as discussed in Witness Beveridge's testimony.

Q. WHICH RATE SCHEDULES ARE IMPACTED BY THE COMPANY'S PROPOSED UPDATES TO TOU PERIODS?

A. The impacted rate schedules would include the redesigned RT schedule and the redesigned OPT-V schedule. Schedules RSTC, RETC, and SGSTC already use the proposed periods and will not be impacted.

Q. WHAT ARE SOME OF THE BENEFITS OF THE NEW TOU PERIODS?

A. The Company's rate designs with refreshed TOU periods benefit customers and advance several policy goals. The new TOU periods properly align price signals to the cost differences that exist across seasons and hours, encouraging peak load reduction and efficient system usage. In addition, proposed on-peak periods of three-hour duration provide the opportunity for economic use of battery storage in a manner aligned with system cost. Superior price signals to customers encourage adoption of new technologies, such as smart energy management devices, energy storage, and EVs. Higher on-peak prices encourage customers to improve insulation and invest in more efficient HVAC systems by providing price signals to use such technology to push energy consumption away from the peak. The proposed Discount periods encourage EV charging or other flexible consumption during times of low system costs, providing incentives for distributed energy resource adoption.

III. RATE DESIGN CHANGES FOR RESIDENTIAL CUSTOMERS

A. Redesigned RT Rate with Two-Part Demand

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REVISION TO ITS RT SCHEDULE.

A The Company proposes to revise the RT rate schedule based upon the new TOU periods, as discussed above. In addition, the Company is proposing that the demand structure for RT be modified to include two parts: (1) a demand charge component for the highest on-peak demand; and (2) a demand charge component for the highest demand regardless of TOU period. Such a structure is important to ensure recovery of fixed distribution costs for customers who may wish to use batteries to avoid peak demand charges.

B. Reduced Seasonality in Rates

Q. WHAT CHANGE IS THE COMPANY PROPOSING REGARDING SEASONALITY OF RATES FOR RESIDENTIAL CUSTOMERS?

A. The Company is proposing to reduce seasonal pricing, which differentiates between winter and summer, for residential customers. The Company believes such changes are appropriate given the increasing importance of resources to cover both winter and summer peaks. Additionally, the modernized TOU periods serve to provide adequate pricing signals based on seasonal system loads, as the On-Peak, Off-Peak, and Discount pricing time periods are differentiated by season.

IV. RATE DESIGN CHANGES FOR NON-RESIDENTIAL CUSTOMERS

A. Demand Charge Structure Alignment to TOU Periods

Q. HOW IS THE COMPANY PROPOSING TO CHANGE THE DEMAND CHARGE STRUCTURE FOR NON-RESIDENTIAL CUSTOMERS?

A. As the TOU periods transition to a three time-period structure, the non-residential demand structure must also change to maintain and improve upon the price structure alignment with system costs. This will also provide actionable price signals to customers with flexible loads or enabled technology. Both objectives are important and must be held in balance when designing the ultimate rate structure. The three-part structure the Company is proposing is described below, including the costs each charge is conceptually designed to recover.

- Base Demand Charge: This charge is designed to recover distribution costs, which are the system costs in closest proximity to the distribution-served customers. Such costs are not driven by overall system demand and are generally fixed throughout the year. Accordingly, the Base Demand Charge would apply to the higher of (1) the customer's highest maximum demand across all periods over the last 12 months, or (2) 50% of the Contract Demand.
- Mid-Peak Demand Charge: This charge is designed to recover off-peak and discount allocation of production and transmission costs. This charge recovers capacity costs incurred to provide service during non-peak times.

Accordingly, the Mid-Peak Demand Charge would apply to the customer's maximum demand during off-peak or on-peak periods (excludes discount).

- On-Peak Demand Charge: This charge is designed to recover peak allocation of production and transmission costs resulting from the customer's contribution to system demand during peak hours. Accordingly, the On-Peak Demand Charge would apply to the customer's measured on-peak demand.

The three-part demand structure will improve price transparency and better align with cost causation based on both the size and timing of customer demands. Mid-Peak and On-Peak Demand Charges reflect the reality that demands at certain times impose more or less costs on the production and transmission components of the electric system. Similarly, the Base Demand Charge recovers system costs most directly caused by specific customers that do not vary based on the time of use (either by hour, by day, or by month). The Base Demand Charge reduces bill volatility for customers, while the Mid-Peak and On-Peak Demand Charges offer opportunities for customers to reduce their peaks and lower their bills. Relative recovery of costs between the three parts of this proposed demand charge structure was determined by using the CDM to maintain cost causation linkage, as well as alignment with the methodologies used to set TOU energy charges. This new demand charge structure works in tandem with the updated TOU periods described above, which govern both energy and demand charges.

Q. WHICH RATE SCHEDULE WILL BE AFFECTED BY THE CHANGE TO THE DEMAND CHARGE STRUCTURE FOR NON-RESIDENTIAL CUSTOMERS?

A. The only impacted rate schedule would be OPT-V.

Q. ARE THERE OTHER CHANGES THE COMPANY IS PROPOSING RELATIVE TO DEMAND CHARGES?

A. Yes. During the CRDS, stakeholders requested information about the recovery of fixed costs through energy charges and asked whether such costs should be shifted more towards demand charges. Accordingly, the Company evaluated the alignment of bills/pricing to cost causation. The analysis showed that shifting a portion of fixed cost recovery from energy charges to demand charges improved alignment to cost causation across a wide spectrum of customer energy usage profiles. Importantly, a slight increase in demand charges, paired with a corresponding decrease in energy charges, could improve alignment in a meaningful way, with very little impact on bills for customers. As a result, Witness Beveridge is proposing pricing which reflects slightly higher recovery through demand charges for TOU rates.

B. Reduced Seasonality in Rates

Q. WHAT CHANGE IS THE COMPANY PROPOSING REGARDING SEASONALITY OF RATES FOR NON-RESIDENTIAL CUSTOMERS?

A. The Company is proposing to reduce seasonal pricing, which differentiates between winter and summer, for non-residential customers. The Company believes such changes are appropriate given the increasing importance of resources to cover both winter and summer peaks. Additionally, the modernized TOU periods serve to provide adequate pricing signals based on seasonal system loads, as the On-Peak, Off-Peak, and Discount pricing time periods are differentiated by season.

C. Non-Residential Net Energy Metering Changes

Q. WHAT CHANGES IS THE COMPANY PROPOSING TO MAKE TO NET ENERGY METERING FOR NON-RESIDENTIAL CUSTOMERS?

A. The Company is proposing changes to Net Energy Metering ("NEM") as a result of the new TOU periods and the new three-part demand charge structure described above. The Company is proposing a new Non-Residential Solar Choice Rider which will implement several changes for non-residential customers seeking to pursue self-generation through NEM. The proposed rider can be found in Byrd Exhibit 7. The rider requires that all future NEM customers be served under a general service or industrial rate schedule that includes TOU periods. Importantly, for larger customers and larger systems, the Company's TOU periods include the modified demand charge structure described above, ensuring price alignment with system utilization and cost causation. The remaining changes are directly enabled or result from this new foundation.

Currently, NEM systems are limited to the "lesser of the Customer's estimated maximum annual kilowatt demand or 1,000 kilowatts." For Customer-owned generation installations, the Company is proposing to increase the size limit to the lesser of 100% of the Customer's contract demand or 5,000 kilowatts ("kW"). Such changes are appropriate as the new TOU periods and three-part demand structure discussed above will provide cost recovery assurance for fixed costs. In accordance with N.C. Gen. Stat. § 62-126.3(14), the Company is not proposing a change to the system size limitations for customers with leased generation facilities.

Finally, the Company is proposing to net exported energy against usage by TOU period on a monthly basis. Any exported energy that was not used to offset billed usage in the month would be credited to the customer at an average avoided cost rate, using the Net Excess Energy Credit calculation proposed by the Company in the *Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC* filed April 1, 2022 in Docket No. E-100, Sub 175.

In aggregate, these changes were discussed during the CRDS and included in the Roadmap for consideration in the Company's next rate case.

Q. WHAT CHANGES ARE YOU PROPOSING FOR THE EXISTING RIDER NM?

A. The Company is proposing that all new non-residential NEM applications take service under Rider NSC, as described above. Accordingly, only existing non-residential NEM customers served under Rider NM prior to the availability of Rider NSC would continue service under Rider NM. The Company proposes to freeze Rider NM to new customers as of January 1, 2024 and allow existing NEM customers to continue service under Rider NM until they request service under Rider NSC or until December 31, 2033, at which point all non-residential NEM customers receiving service under Rider NM will be moved to Rider NSC or another appropriate tariff, as available at that time.

As described above, the Company is proposing to modify the TOU periods such that May through September will be treated as summer months. Rider NM presently resets accumulated Excess Energy to zero at the beginning of each summer season, currently June 1. The Company proposes to change the reset date to April 30 to correspond with the season definitions in the Company's proposed TOU rates.

D. Redesigned Hourly Pricing Tariff

Q. WHY IS THE COMPANY PROPOSING A REDESIGNED HOURLY PRICING RATE?

A. During the CRDS, stakeholders expressed an interest in certain changes to yield a more flexible marginal price rate with expanded availability.

Q. WILL YOU PLEASE DESCRIBE THE PROPOSED REDESIGNED HOURLY PRICING RATE?

A. The proposed Hourly Pricing rate will provide broader access for customers to marginal pricing. In addition, the new tariff will have features that encourage customers to be consistently price-responsive during times of grid constraints to retain that expanded access to marginal pricing. Byrd Exhibit 7 includes the revised tariff sheet showing the mechanics behind the redesigned rate. The tariff will remain available to all customers with load greater than 1,000 kW. The Company proposes to reestablish Customer Baseline Load ("CBL") every four years based on the customer's 12-month usage history, with modifications to reflect price-responsiveness during times of grid constraints. The CBL defines the level above which all kilowatt-hours ("kWh") will be billed at hourly marginal energy prices. This new approach to reestablishing CBLs will restrict marginal prices to only four years for growing loads that are not consistently price-responsive, resulting in embedded cost recovery from such loads after the periodic CBL reestablishment. The CBL would be maintained or adjusted downwards, if mutually agreeable to the customer and Company, to the extent the customer consistently reduces loads during times when grid constraints result in rationing charges within the hourly prices. The Company would allow for lower CBLs based on the average amount of reduction below the current CBL that the customer exhibited over a proceeding four-year period, in accordance with Byrd Exhibit 7. The Company will include a margin adder of $6 per megawatt-hour to account for day-ahead pricing uncertainty and provide some fixed cost recovery from the marginal energy purchases. Existing loads will be able to participate through establishment of an initial CBL and subsequent demonstration of price responsiveness, subject to the automatic CBL reestablishment process described above. The program design balances marginal pricing opportunities for incremental loads with assurance of embedded cost recovery from loads with limited price-responsiveness that drive future resource investment. As desired by stakeholders and discussed in the CRDS, the proposed rate allows for greater exposure to marginal prices, provided customers demonstrate price-responsiveness during grid events. Notably, the Company is proposing to eliminate the participation cap due to the durability and scalability of the new program design.

Q. HOW WILL THE REDESIGN OF SCHEDULE HP IMPACT EXISTING CUSTOMERS SERVED ON THE RATE?

A. Pricing changes will be effective for existing customers, but the requirement for automatic CBL reestablishment every four years will not apply unless and until the customer requests an update of their CBL for any reason. This grandfathering provision is specified in the proposed Schedule HP tariff.

E. Economic Development

Q. WHY IS THE COMPANY PROPOSING A NEW ECONOMIC DEVELOPMENT RIDER?

A. The Company is proposing a new rider that will improve competitiveness for attracting and retaining customers that are adding jobs and making capital investments in the Company's service territory. The Company's existing Economic Development Rider, Rider EC, provides varying credit levels based on load factor but offers little flexibility otherwise. The Company's proposed new Economic Development Rider, Rider ED, affords greater flexibility to tailor benefits based on both electric grid and regional economic benefits associated with the participant's investment and load characteristics. The proposed changes are included in Byrd Exhibit 7.

Importantly, the changes proposed below flow from discussions with stakeholders and match the ideas put forth in the Company's CRDS Roadmap. For example, the project attributes in the proposed tariff used to determine benefits are the same factors provided in the Roadmap. Thus, the proposed tariff not only provides the benefits outlined in more detail below, but directly incorporates ideas and outcomes from stakeholders via the CRDS.

Q. TO WHICH CUSTOMERS WILL THE PROPOSED RIDER ED BE AVAILABLE?

A. Availability will be limited to customers with new load exceeding 1,000 kW with a minimum load factor of 40%. Additionally, participants must have applied for and received economic assistance from either the state or local government or another public agency. Participants must also meet certain employment and investment minimums relative to the size of the new load.

Q. DOES THE RIDER INCLUDE ANY EXCEPTIONS TO THESE AVAILABILITY CRITERIA?

A. Yes. New loads which are predominantly for serving EV charging are exempted from employment and load factor requirements and may participate for new load sizes above 500 kW (as opposed to 1,000 kW otherwise). Additionally, existing customers considering plant investments with possible relocation outside of the Company's service territory may qualify by meeting the investment and employment thresholds, but the new load calculation will exclude reductions associated with the removal of historic equipment and/or processes.

Q. PLEASE DESCRIBE THE OTHER IMPROVEMENTS INCLUDED IN THE NEW RIDER.

A. The proposed Rider ED contains several improvements, including the following:

- **Flexible Benefits** – The existing Rider EC provides benefits that vary across customers based solely on load factor differences. The Company recognizes that economic development brings value to the state based on a number of factors, and therefore the proposed Rider ED will consider the following criteria in developing appropriate benefit levels on an individual customer basis:

- Peak monthly demand
- Average monthly load factor
- The Company's incremental costs to serve
- Number of new full-time employees
- Economic multiplier
- Total new capital investment of the customer.

- **Extended Ramp up Period** – The existing Rider EC requires participants to begin taking credits 18 months after the first date service is supplied under the contract. The proposed Rider EC extends this period to 36 months, recognizing that some industries require significant start-up time for new facilities, and 18 months constrains their ability to take advantage of the rider benefits.
- **Term** – The existing Rider EC provides benefits that steadily decline over a five-year period on a rigid schedule. The proposed Rider ED provides greater flexibility by allowing benefits up to 10 years, with possible differences across the years as determined by the project merits. For example, projects receiving greater levels of benefits for longer periods will necessarily meet higher thresholds of investment and employment, as described above.

- **Benefit Structure** – The existing Rider EC provides a reduction in total charges (excluding certain riders and Extra Facilities) The proposed Rider ED provides a reduction of up to 75% of the applicable demand charges on the monthly bill.

Q. PLEASE DESCRIBE THE BENEFITS OF THE PROPOSED ECONOMIC DEVELOPMENT RIDER.

A. Electric costs are often one of a few deciding factors that influence an economic development prospect's selection of one location over another, especially for electric-intensive operations in the manufacturing or high-technology fields. The proposed new Economic Development Rider would enable the Company to assist North Carolina and local communities in competing for projects. Ultimately, expanded load through economic development reduces the prices paid by all customers, through contribution to fixed cost recovery, and promotes the prosperity of the citizens and businesses in the Company's territory.

Q. HOW DOES THE NEW ECONOMIC DEVELOPMENT RIDER BALANCE AND ALIGN THE GOALS OF ATTRACTING NEW ECONOMIC DEVELOPMENT WITH THE INTERESTS OF EXISTING CUSTOMERS?

A. Benefits under Rider ED will reflect broad state and/or regional benefits by scaling with both grid beneficial attributes as well as economic factors such as employment and capital investment levels. The awarded benefits are also reduced if the new load requires significant incremental grid investments in order to provide service, protecting the interest of other customers.

Additionally, the proposed Rider ED provides benefits based on a discount applied against demand charges, maintaining the Company's ability to recover potentially volatile and/or rising fuel costs from Rider ED participants, thereby continuing to protect non-participants from such exposures. Importantly, Rider ED contains termination penalties that require repayment of benefits in the event a participant subsequently terminates the agreement. Finally, only projects receiving state or local government or other agency support will receive benefits, ensuring alignment between Rider ED benefits and the economic development goals of North Carolina. Taken together, these improvements incorporate consideration of the interests of both economic development prospects and existing customers and thereby provide benefits to both.

Q. DOES THE COMPANY PROPOSE TO CLOSE THE EXISTING ECONOMIC DEVELOPMENT RIDER (RIDER EC) AND ECONOMIC REDEVELOPMENT RIDER (RIDER ER) TO NEW APPLICANTS?

A. Yes. The Company proposes to close to new applications the existing Economic Development Rider, Rider EC, and the Economic Redevelopment Rider, Rider ER. Customers currently served under these riders will continue to take service under the existing riders until completion of their existing contracts.

F. New High Load Factor Tariff

Q. WHY IS THE COMPANY PROPOSING A NEW HLF RATE?

A. As part of the collaborative CRDS process, stakeholders expressed interest in rate options reflecting the cost causation differences between loads of varying load factors as higher load factors generally correspond to more efficient use of grid resources (i.e., fixed assets). Based on discussions with stakeholders on the potential for such rates, the Company is proposing a High Load Factor tariff, Schedule HLF, that provides a simple, cost of service based pricing structure that may prove attractive to customers with very high load factors.

Q. WILL YOU PLEASE EXPLAIN THE STRUCTURE OF THE PROPOSED HLF RATE?

A. Byrd Exhibit 7 contains the tariff for the proposed HLF rate, which is a simple design based on demand and energy pricing resulting from the cost of service study with a high level of fixed cost recovery coming through demand charges. The rate is not TOU-based, as participating customers are assumed to have consistent loads that do not or cannot vary with time of day, including very little variation across days or even seasons. The structure consists of a Basic Customer Charge, a single demand rate, and a single energy rate for all energy consumed. Fixed costs are predominantly recovered through the demand charge, which is thus comparatively higher than the demand charges in the Company's other general service tariffs. Additionally, demand charges are based on a billing demand defined as the highest of (1) the highest demand in the billing month, (2) 90% of the highest demand during the preceding 11 months, (3) 75% of Contract Demand, or (4) 1,000 kW. The Company thus expects that only very consistent loads with little demand variation would likely find the rate attractive.

Q. IS AVAILABILITY RESTRICTED TO CUSTOMERS WITH CERTAIN LOAD FACTORS?

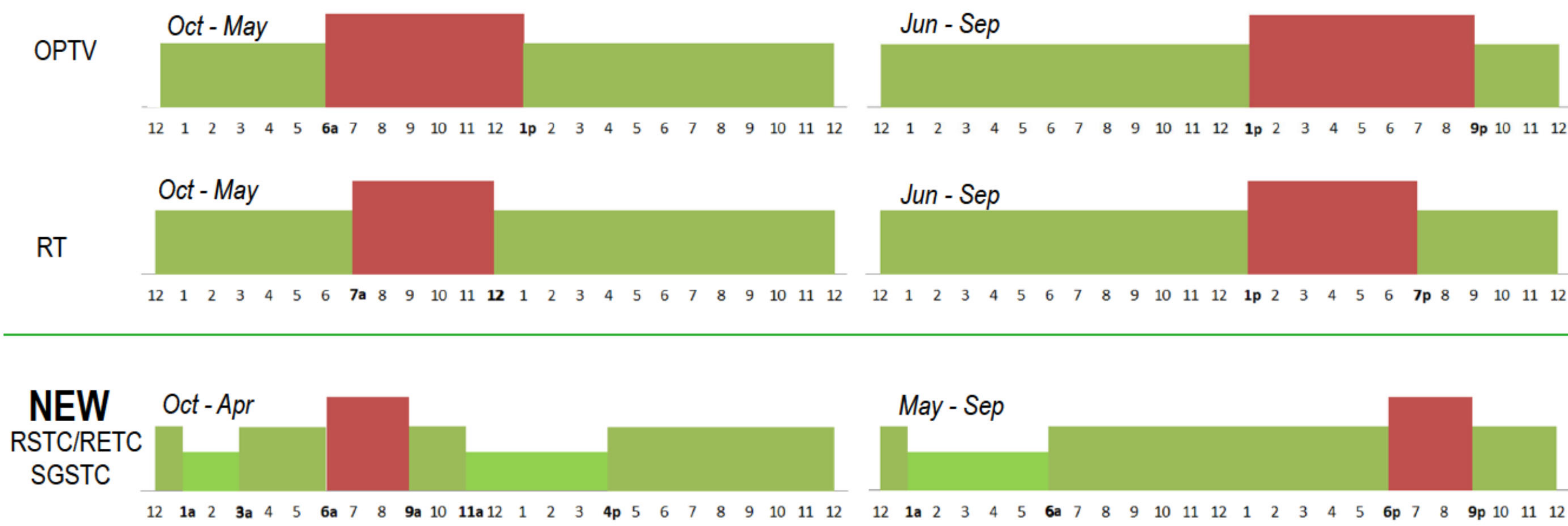
A. No. The rate does not explicitly limit participation to customers with high load factors but rather uses the pricing design to limit the attractiveness of the rate to such customers. In other words, while the rate is generally available to non-residential customers who meet the minimum demand qualification, the pricing design is such that lower load factor customers would typically not find the rate attractive.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

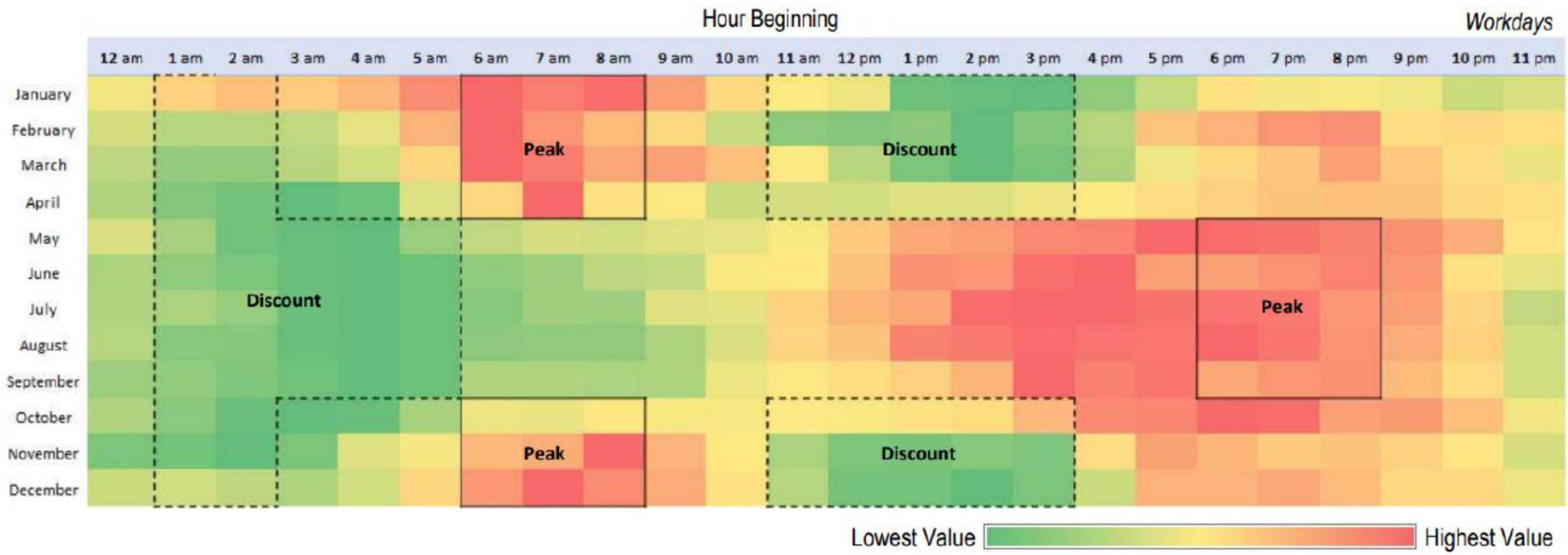
A. Yes.

DEC-NC TOU Period Comparison



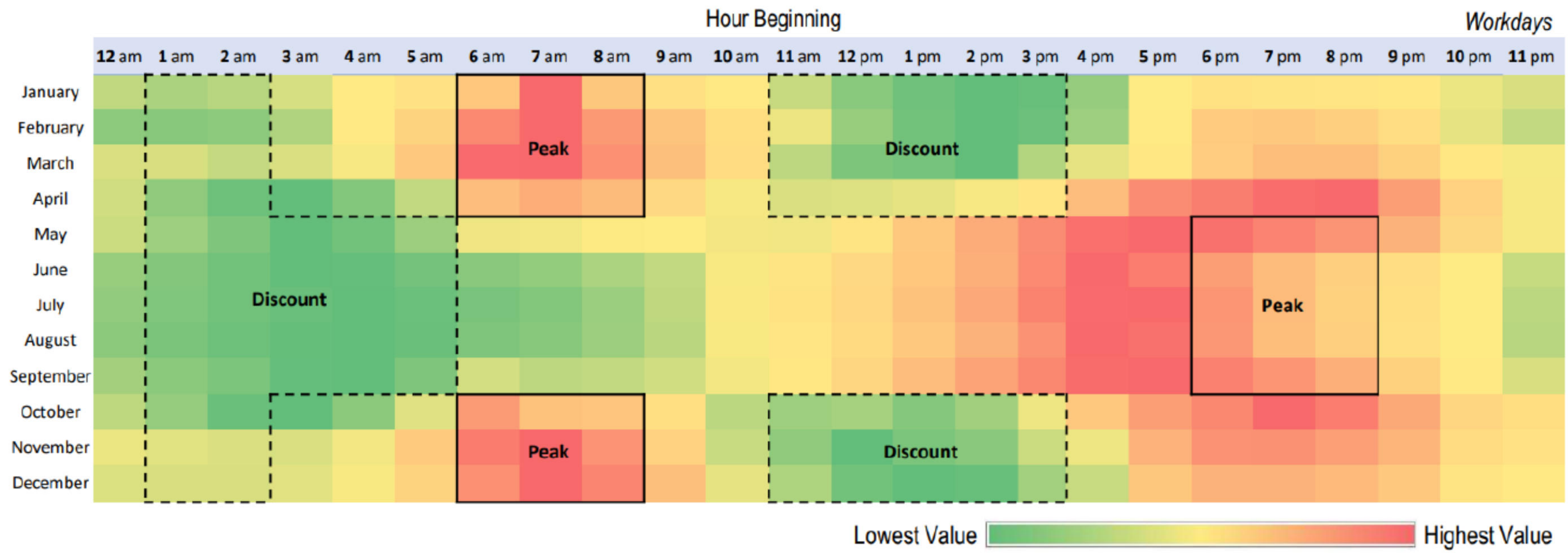
The Company proposes using the pricing periods for the recently approved Critical Peak Pricing rates across the Company's other major tariffs.

TOU Period and Marginal Energy Costs (2018-2020)



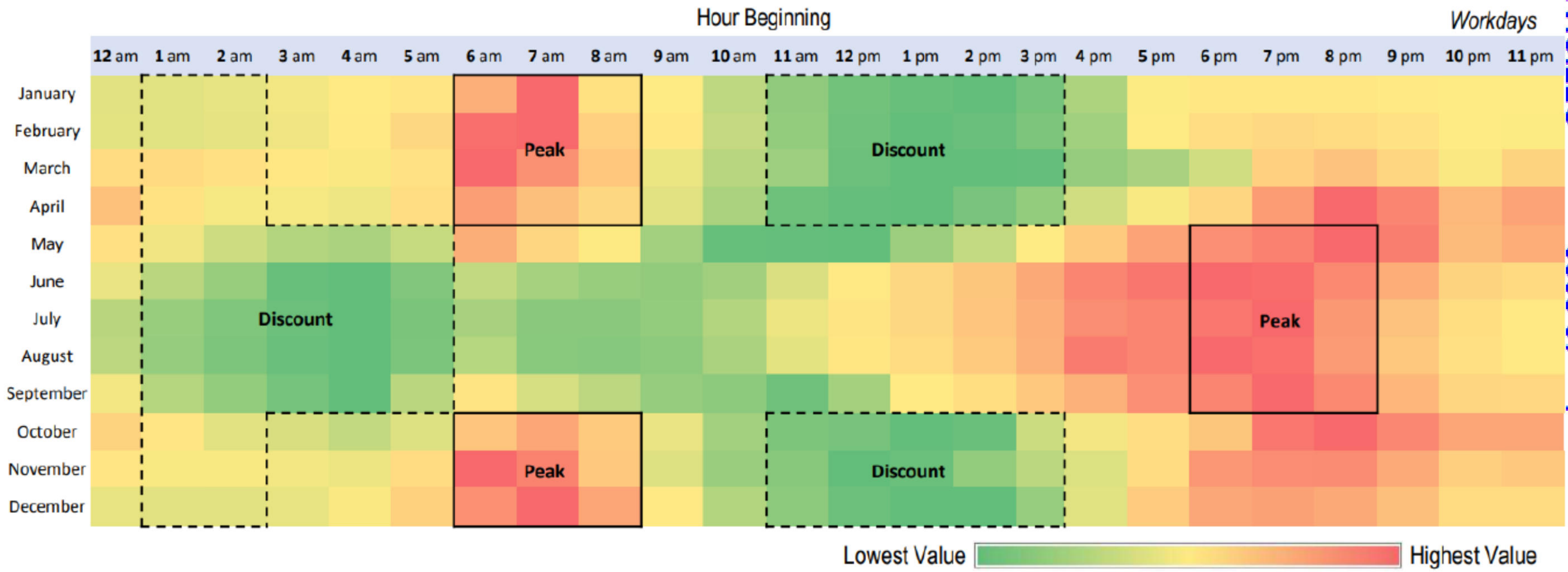
Historical view of actual Marginal Energy Cost aligns with discount and peak-periods

Cost Duration Model: **2021**



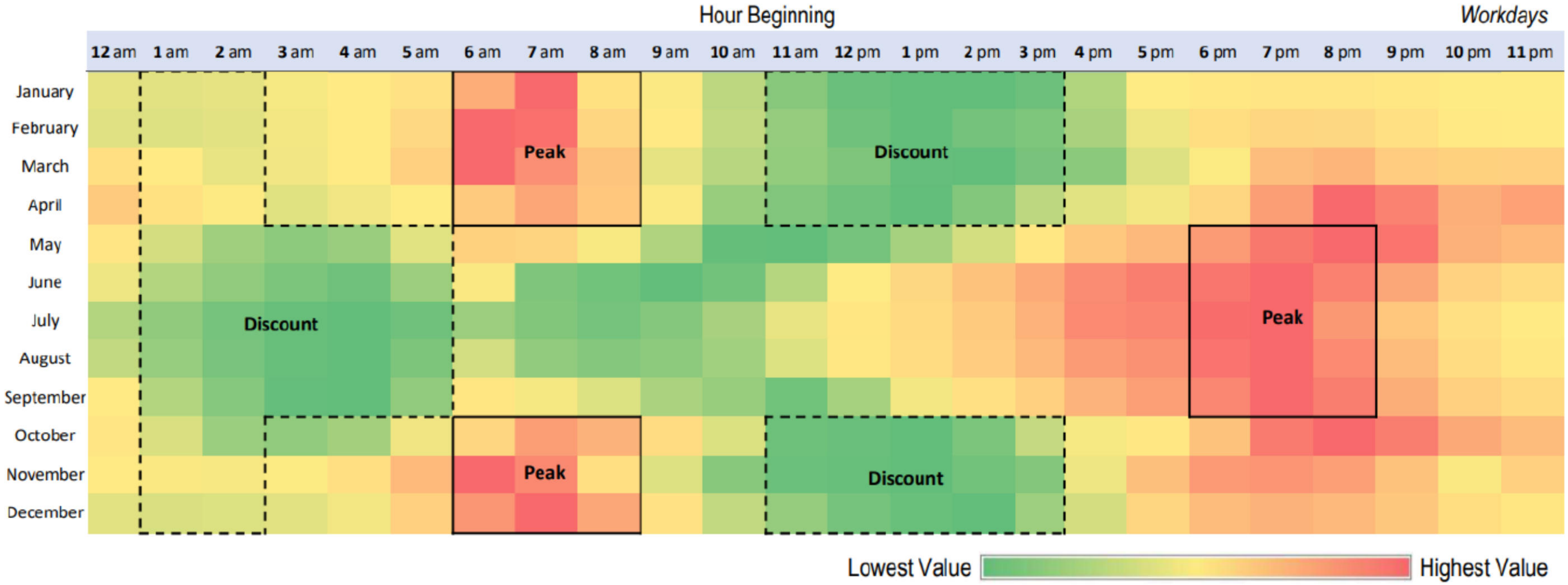
- Relative pricing on an intra-month basis, with hours compared to other hours in that same month only
- Cost Duration Model provides weighted-average view of cost of service
- Discount and winter peak periods align with costs in 2021-2030
- Summer peak shifts later in the evening from 2021-2030 due to increases in solar generation on the system
  - Compare with Byrd Exhibit 4 and Byrd Exhibit 5

Cost Duration Model: **2026**



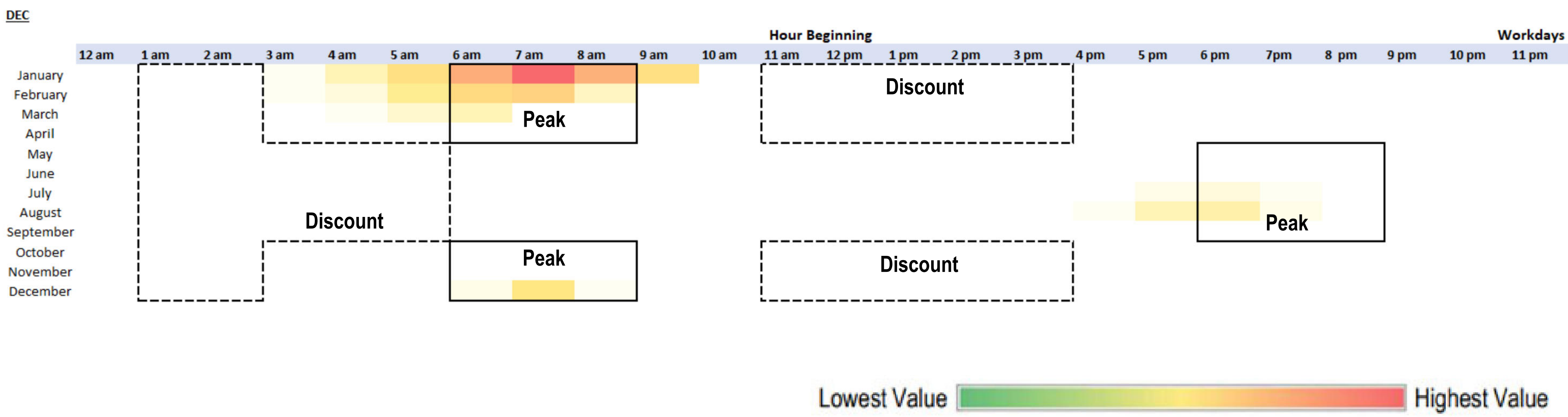
- Summer peak aligns with proposed peak period beyond 2025
- Winter mid-day costs decline on a relative basis, while costs remain low for overnight discount period

Cost Duration Model: **2030**



- Proposed peak period suitable for summer at least through 2030, ensuring durability of proposed TOU periods
- Mid-day costs in winter continue to drop in later years due to solar, on a relative basis
- Costs remain low for overnight discount period

Loss of Load Expectation: **2024**



- From 2020 Resource Adequacy Study

SCHEDULE HP
HOURLY PRICING

AVAILABILITY

Available to non-residential establishments with a minimum Contract Demand of 1,000 kW who qualify for service under the Company's rate schedules LGS, I, OPT-V or HLF.

Service under this Schedule shall be used solely by the contracting Customer in a single enterprise, located entirely on a single, contiguous premises.

This Schedule is not available for a customer who qualifies for a residential schedule, nor for auxiliary or breakdown service. Power delivered under this schedule shall not be used for resale or as a substitute for power contracted for or which may be contracted for, under any other schedule of the Company, except at the option of the Company, under special terms and conditions expressed in writing in the contract with the Customer.

The obligations of the Company in regard to supplying power are dependent upon its securing and retaining all necessary rights-of-way, privileges, franchises and permits, for the delivery of such power. The Company shall not be liable to any customer or applicant for power in the event it is delayed in, or is prevented from, furnishing the power by its failure to secure and retain such rights-of-way, rights, privileges, franchises and permits.

The Company may cancel this schedule at any time it deems necessary.

TYPE OF SERVICE

The Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts; or
3-phase, 208Y/120 volts, 460Y/265 volts, 480Y/277 volts; or
3-phase, 3-wire, 240, 460, 480, 575, or 2300 volts; or
3-phase, 4160Y/2400, 12470Y/7200, or 24940Y/14400 volts; or
3-phase voltages other than those listed above may be available at the Company's option if the size of the Customer's contract warrants a substation solely to serve that Customer, and if the Customer furnishes suitable outdoor space on the premises to accommodate a ground-type transformer installation, or substation, or a transformer vault built in accordance with the Company's specifications.

The type of service supplied will depend upon the voltage available. Prospective customers should determine the available voltage by contacting the nearest office of the Company before purchasing equipment.

Motors of less than 5 H.P. may be single-phase. All motors of more than 5 H.P. must be equipped with starting compensators. The Company reserves the right, when in its opinion the installation would not be detrimental to the service of the Company, to permit other types of motors.

BILL DETERMINATION

The monthly bill shall consist of the following charges:

I. Baseline Charge = sum of charges under the Customer's baseline rate schedule for their Customer Baseline Load
II. Administrative Charge = $200 per month
III. Energy Charge = sum of [(New Load kWh – Reduced Load kWh) x Hourly Energy Price]
IV. Capacity Charge = sum of [(New Load kWh – Reduced Load kWh) x Hourly Capacity Price]
V. Incentive Margin = 0.6 cents per kWh of Net New Load
VI. Incremental Demand Charge = $0.93 per kW of Incremental Demand for Distribution Service
= $0.93 per kW of Incremental Demand for Transmission Service

SCHEDULE HP
HOURLY PRICING

DEFINITIONS

Customer Baseline Load (CBL): The CBL is one full year of hourly loads representing the Customer's energy use and load pattern on their baseline rate schedule. The CBL, as agreed to by the Customer and the Company, is defined in terms of average kWh per hour and max kW, by calendar month and by time-of-use (TOU) period, if applicable. The CBL is based on the Customer's historical usage, where available, and may be adjusted for load responsiveness as described in the Customer Baseline Load provisions below. The Customer is billed or credited at Hourly Prices for actual usage above or below their CBL.

New Load: New Load (kWh) is the amount by which actual kWh exceeds CBL kWh for any hour.

Reduced Load: Reduced Load (kWh) is the amount by which actual kWh is less than CBL kWh for any hour.

Net New Load: Net New Load (kWh) is equal to New Load kWh minus Reduced Load.

Incremental Demand: Incremental Demand (kW) is the amount by which actual kW (maximum 30-minute demand during the current billing month) exceeds CBL kW for the same billing month.

Contract Demand: The maximum demand to be delivered under this Schedule.

CUSTOMER BASELINE LOAD

Initial CBL Establishment:

An initial CBL will be established based on the Customer's load history in the previous 12 months, as determined by the Company and agreed to by the Customer. Adjustments or use of prior load history may be allowed in such cases as permanent removal or addition of equipment; installation of permanent energy efficiency measures; installation of parallel generation; nonrepresentative load patterns from extraordinary events; and plant shutdowns.

CBL Modifications:

CBL's are required to be re-established after four (4) years. Subsequent CBL's will be established using the same process and considerations as the initial CBL for existing customers, in addition to the Load Response Adjustment described below. Customers may request an update to their CBL no earlier than 12 months from their previous CBL. Customers served under Schedule HP before January 1, 2024 under continually effective agreements are not required to re-establish their CBL after four years unless and until the Customer requests an update of their CBL for any reason.

Load Response Adjustment:

For customers on a TOU baseline schedule, CBL modifications may include a Load Response Adjustment, at the Customer's option and requiring at least 48 months of representative load history on Schedule HP. The Adjustment reduces the Customer's CBL for demonstrated load reductions on days when Hourly Capacity Prices are in effect. The Company will calculate the Customer's weighted average Load Response Factor, as a percentage of load, over the previous 48 months. The Customer's On-Peak CBL (kW and kWh) will be reduced by the full Load Response Factor, and the Customer's Off-Peak CBL will be reduced by half of the Load Response Factor. CBL's for Discount hours will not be adjusted.

HOURLY PRICING

Each business day by 4:00 p.m., the Hourly Energy Prices and Hourly Capacity Prices (if applicable) for the 24 hours of the following day will be communicated to the Customer. Prices for weekends and Company holidays will be communicated to the Customer by 4:00 p m. on the last business day before the weekend or holiday. The Customer is responsible for notifying the company if he or she fails to receive the price information.

Hourly Energy Prices are based on the Company's forecasted marginal energy cost in each hour, which includes marginal fuel, variable operating and maintenance expenses, and an adjustment for delivery line losses.

SCHEDULE HP
HOURLY PRICING

Hourly Capacity Prices are applicable when the daily forecast indicates a reserve ratio of 1.15 or less, calculated as available generation divided by system demand. The Hourly Capacity Price is zero for all other hours of the year. When applicable, the Hourly Capacity Price is a tiered rate based on the forecasted reserve ratio, reflecting the marginal cost of production capacity.

RIDERS

The Renewable Energy Portfolio Standard (REPS) Rider charge as shown on Leaf No. 68 and the Customer Assistance Recovery Rider charge as shown on Leaf No. 144 will be added to the monthly bill for each agreement for service under this schedule.

The following Riders are applicable to service supplied under this schedule. The currently approved cents/kWh rider increment or decrement must be added to the cents/kWh rates shown above to determine the monthly bill.

Leaf No. 60	Fuel Cost Adjustment Rider (applicable to Baseline Charge only)
Leaf No. 62	Energy Efficiency Rider
Leaf No. 64	Existing DSM Program Costs Adjustment Rider
Leaf No. 105	BPM Prospective Rider
Leaf No. 106	BPM True-Up Rider
Leaf No. 127	CPRE Rider
Leaf No. 129	EDIT-3 Rider
Leaf No. 131	EDIT-4 Rider

A Storm Securitization Rider charge will be added to the monthly bill based on the currently approved cents/kWh incremental rate as shown in Leaf No. 133.

PROVISION FOR CUSTOMERS OPERATING IN PARALLEL WITH THE COMPANY

Customers served under this Schedule are permitted to operate power generating facilities in parallel with the Company, with a maximum operating capacity of 50 megawatts or less. If a customer has power generating facilities that are not governed by another parallel generation rate schedule or rider, the Standby Charge, Determination of Standby Charges, and Interconnection Facilities Charge provisions of Schedule PG shall be applicable to service under this Schedule. The Incremental Demand Charge does not apply to any incremental demand that is less than Standby Demand. In addition, customers operating a generator in parallel with the Company's system must comply with the provisions outlined in the North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections (hereinafter "Interconnection Procedures") as approved by the North Carolina Utilities Commission.

PROVISION FOR CUSTOMERS SERVED UNDER RIDER IS

For customers served under Rider IS, the Interruptible Contract Demand shall be the same as that contracted for during the baseline period. Further, the calculation of the Effective Interruptible Demand (EID) each month will exclude all energy consumed above the CBL. Hourly Capacity Prices will not apply to Reduced Load above Firm Contract Demand during the hours of interruption periods.

PROVISION FOR CUSTOMERS SERVED UNDER RIDER PS

For customers served under PowerShare Rider PS, the Maximum Curtailable Demand shall be the same as that contracted for during the baseline period, and the PowerShare Firm Demand must be at least 100 kW less than the CBL. Further, the calculation of the Effective Curtailable Demand (ECD) each month will exclude all energy consumed above the CBL. The PowerShare Curtailed Energy Credit will apply to only the load curtailed between the Firm Demand and the smaller of the Forecasted Demand and the CBL, provided the Forecasted Demand is greater than the Firm Demand. Hourly Energy Prices and Hourly Capacity Prices will not apply to Reduced Load above the PowerShare Firm Demand during a Curtailment Period.

SCHEDULE HP
HOURLY PRICING

POWER FACTOR ADJUSTMENT

The Company will adjust, for power factor, the kWh for any customer operating in parallel, and may adjust the kWh for any other customer served under this schedule. The power factor adjustment may result in a Power Factor Charge, if applicable, as follows:

Power Factor Charge = Sum of Hourly Load Correction Amounts for all hours in the billing period, but not less than zero,

Where:

Hourly Load Correction Amount = Hourly Load Correction kWh x Hourly Price
Hourly Load Correction kWh = [total hourly kWh x (0.85 ÷ hourly power factor)] – total hourly kWh

PAYMENT

Bills under this Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the twenty-fifth day after the date of the bill. If any bill is not so paid, the Company has the right to suspend service. In addition, all bills not paid by the twenty-fifth day after the date of the bill shall be subject to a one percent (1%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill, and it shall become part of and be due and payable with the bill on which it is rendered.

CONTRACT PERIOD

Each Customer shall enter into a contract to purchase electricity under this schedule for a minimum original term of one (1) year, and thereafter from year to year upon the condition that either party can terminate the contract at the end of the original term, or at any time thereafter, by giving at least sixty (60) days previous notice of such termination in writing.

If the Customer requests an amendment to or termination of the service agreement before the expiration of the initial term of the agreement, the Customer shall pay to the Company an early termination charge as set forth in the Company's Service Regulations.

SCHEDULE HLF
HIGH LOAD FACTOR

AVAILABILITY

Available to the individual customer with a kilowatt demand of 1,000 kW or more.

Service under this Schedule shall be used solely by the contracting Customer in a single enterprise, located entirely on a single, contiguous premises.

This Schedule is not available to the individual customer who qualifies for a residential or industrial schedule nor for auxiliary or breakdown service. Power delivered under this schedule shall not be used for resale or exchange or in parallel with other electric power or as a substitute for power contracted for or which may be contracted for, under any other schedule of the Company, except at the option of the Company, or for service in conjunction with Riders SCG, NM or NSC, under special terms and conditions expressed in writing in the contract with the customer.

The obligations of the Company in regard to supplying power are dependent upon its securing and retaining all necessary rights-of-way, privileges, franchises and permits, for the delivery of such power. The Company shall not be liable to any customer or applicant for power in the event it is delayed in or is prevented from, furnishing the power by its failure to secure and retain such rights-of-way, rights, privileges, franchises and permits.

TYPE OF SERVICE

The Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts, 120/208 volts, 240/480 volts or other available single-phase voltages at the company's option; or
3-phase, 208Y/120 volts, 460Y/265 volts, 480Y/277 volts; or
3-phase, 3-wire, 240, 460, 480, 575, or 2300 volts: or
3-phase, 4160Y/2400, 12470Y/7200, or 24940Y/14400 volts; or
3-phase voltages other than those listed above may be available at the Company's option if the size of the Customer's contract warrants a substation solely to serve that Customer, and if the Customer furnishes suitable outdoor space on the premises to accommodate a ground-type transformer installation, or substation, or a transformer vault built in accordance with the Company's specifications.

The type of service supplied will depend upon the voltage available. Prospective customers should determine the available voltage by contacting the nearest office of the Company before purchasing equipment.

Motors of less than 5 H.P. may be single-phase. All motors of more than 5 H.P. must be equipped with starting compensators. The Company reserves the right, when in its opinion the installation would not be detrimental to the service of the Company, to permit other types of motors.

RATE

I.	Basic Customer Charge per month	$34.00		
II.	Energy Charge per kWh, per month	2.6603¢		
		Secondary	Primary	Transmission
III.	Demand Charge per kW of Billing Demand, per month	$19.50	$17.94	$17.55

Demand Charge is based on delivery voltage. Secondary service includes delivery voltage less than or equal to 600 volts. Primary service includes delivery voltage greater than 600 volts but less than 44 kV. Transmission service includes delivery voltage greater than or equal to 44 kV.

SCHEDULE HLF
HIGH LOAD FACTOR

RIDERS

The Renewable Energy Portfolio Standard (REPS) Rider charge as shown on Leaf No. 68 and the Customer Assistance Recovery Rider charge as shown on Leaf No. 144 will be added to the monthly bill for each agreement for service under this schedule.

The following Riders are applicable to service supplied under this schedule. The currently approved cents/kWh rider increment or decrement must be added to the cents/kWh rates shown above to determine the monthly bill.

Leaf No. 60	Fuel Cost Adjustment Rider
Leaf No. 62	Energy Efficiency Rider
Leaf No. 64	Existing DSM Program Costs Adjustment Rider
Leaf No. 105	BPM Prospective Rider
Leaf No. 106	BPM True-Up Rider
Leaf No. 127	CPRE Rider
Leaf No. 129	EDIT-3 Rider
Leaf No. 131	EDIT-4 Rider

A Storm Securitization Rider charge will be added to the monthly bill based on the currently approved cents/kWh incremental rate as shown in Leaf No. 133.

DETERMINATION OF BILLING DEMAND

The Billing Demand each month shall be the largest of the following:

1. The maximum 30-minute demand during the current billing month
2. 90% of the maximum 30-minute demand during the previous 12 billing months including the current billing month
3. 75% of the Contract Demand
4. 1,000 kW

Provision 3. related to Contract Demand will apply beginning with the 13th full billing month for new installations.

POWER FACTOR CORRECTION

When the average monthly power factor of the Customer's power requirements is less than 85 percent, the Company may correct the integrated demand in kW for that month by multiplying by 85 percent and dividing by the average power factor in percent for that month.

PAYMENT

Bills under the Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the 25th day after the date of the bill. If any bill is not so paid, the Company has the right to suspend service. In addition, all bills not paid by the 25th day after the date of the bill shall be subject to a one percent (1%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill, and it shall become part of and be due and payable with the bill on which it is rendered.

CONTRACT PERIOD

Each customer shall enter into a contract to purchase electricity from the Company for a minimum original term of one (1) year, and thereafter from year to year upon the condition that either party can terminate the contract at the end of the original term, or at any time thereafter by giving at least 60 days' previous notice of such termination in writing; but the Company may require a contract for a longer original term of years where the requirement is justified by the circumstances. If the Customer requests an amendment to or termination of the service agreement before the expiration of the initial term of the agreement, the Customer shall pay to the Company an early termination charge as set forth in the Company's Service Regulations.

RIDER ED
ECONOMIC DEVELOPMENT

AVAILABILITY

Available, only at Company's option, to nonresidential establishments receiving service under Schedule LGS, I or OPT-V provided that the establishment is not classified as Retail Trade or Public Administration by the North American Industry Classification System (NAICS).

This Rider is available for load associated with initial permanent service to new establishments, expansion of existing establishments, or new customers in existing establishments who make application to Company for service under this Rider, and Company approves such application.

This Rider is not available to a new customer which results from a change in ownership of an existing establishment. However, if a change in ownership occurs after Customer contracts for service under this Rider, the successor Customer may be allowed to fulfill the balance of the contract under this Rider and continue the schedule of credits outlined below. This Rider is also not available for resumption of service following interruptions such as equipment failure, temporary plant shutdown, strike, or economic conditions. This Rider is also not available for: (1) load shifted from one establishment or delivery on Company’s system to another on Company’s system; (2) short-term, construction, or temporary service; or (3) electrical load that results from the shutdown or reduction of generation facilities.

DEFINITIONS

New Load: New Load is that which is added to Company's system by a new establishment. For existing establishments, New Load is the net incremental load above that which existed prior to approval for service under this Rider. The New Load shall exclude any curtailable, back-up, or standby service.

New Load for existing customers considering relocating outside of the Company's service territory may qualify for an Economic Development Bill Factor Reduction. Existing customers must reinvest in existing establishments and meet the capital investment and employment requirements in the Qualifying Criteria in item B below as well as attest to and provide documentation of the consideration to relocate outside of the Company's service territory within the Qualifying Criteria in item C below. New Load shall exclude reductions associated with the removal of equipment and/or processes by existing customers.

Delivery Date: The Delivery Date is the first date service is supplied under the contract.

Operational Date: The Operational Date shall be the date the facility is fully operational as declared by the Customer, but shall be no more than 36 months after the Delivery Date.

QUALIFYING CRITERIA

To participate in this Rider, the Customer must meet the following criteria:

A. The minimum qualifying New Load must have a minimum load factor of 40% at a single point of delivery, must be at least 1,000 kW at the Customer’s single premise, and the Customer must have applied for and received economic assistance from the state or local government or other public agency before the Company will approve a Service Agreement under this Rider, except New Load for existing customers considering relocating outside of the Company's service territory.

B. The new or expanding business must also meet at least one of the following two requirements at the project location:

   1) Customer employs an additional workforce in Company's service area of a minimum of 50 full time equivalent (FTE) employees. Employment additions must occur following Company's approval for service under this Rider.

   2) Customer's New Load must result in capital investment of $500,000 per MW and two (2) new FTE employees per MW by Customer in Company's service area. The capital investment must occur following Company's approval for service under this Rider.

C. Customer must provide written documentation attesting that the availability of this Rider is a significant factor in the Customer’s location/expansion decision.

RIDER ED
ECONOMIC DEVELOPMENT

D. The two (2) new FTE employees in item B.2) and the minimum load factor of 40% requirement in item A are waived for electric vehicle (EV) fleet customers, where 80% of expected energy usage is related to EV charging. Additionally, the minimum qualifying New Load requirement of 1,000 kW in item A is lowered to 500 kW for EV fleet customers. An EV fleet Customer who receives a monthly bill discount under this Rider is not eligible to receive any other EV-related incentives offered by the Company.

GENERAL PROVISIONS

1. Customer must make an application to Company for service under this Rider, and Company must approve such application before Customer may receive service hereunder. The application must include a description of the amount of and nature of the New Load and the basis on which Customer requests qualification shown in the Qualifying Criteria above. In the application, Customer must affirm that availability of this Rider was a factor in Customer's decision to locate the New Load on Company's system. The application shall also specify the total number of FTE employees employed by Customer in all establishments receiving electric service from Company's system, at the time of application for this Rider and on the Operational Date.
2. For Customers contracting under this Rider due to expansion, Company may install metering equipment necessary to measure the New Load to be billed under this Rider separate from the existing load billed under the applicable rate schedule. Company reserves the right to make the determination of whether such installation will be separately metered or sub-metered. If in Company's opinion, the nature of the expansion is such that either separate metering or submetering is impractical or economically infeasible, Company will determine, based on historical usage, what portion of Customer's load, if any, qualifies as New Load eligible for this Rider.
3. All terms and conditions of the Customer's applicable rate schedule shall apply to the service supplied to Customer, except as modified by this Rider.

RATE PER MONTH

All charges shall be those set forth in the Customer's applicable rate schedule with the resulting monthly bill adjusted by the Economic Development Bill Reduction Factor, plus any Extra Facilities Charges as specified in Company's Service Regulations or as otherwise agreed.

ECONOMIC DEVELOPMENT BILL REDUCTION FACTOR

Beginning with the effective date as declared by the Customer and in compliance with this Rider, a reduction in the monthly bill will be applied up to a 75% kW Demand Charge for the qualifying New Load under this Rider.

The percentage discount to be applied to the Customer's monthly bills will be determined in advance, on or prior to the date of execution of a Service Agreement, and will be developed on an individual customer basis given the evaluation of the following criteria as to the New Load:

1. Peak monthly demand;
2. Average monthly load factor;
3. The Company's incremental costs to serve;
4. Number of new FTE employees;
5. Economic multiplier; and
6. Total new capital investment of the Customer.

Item 3 will not take into account the costs for additional facilities that are being covered in full by the Customer through the terms of the Service Agreement or another agreement between the Company and the Customer.

TERM OF SERVICE

The Customer may request the Operational Date as an effective date of this Rider which is no more than 36 months after the Delivery Date. The minimum term of the Service Agreement shall be twice the number of years for which the Customer is receiving a credit

RIDER ED
ECONOMIC DEVELOPMENT

following the Customer's effective date, with the bill reductions being available for a maximum period of 10 years.

PENALTY FOR NON-COMPLIANCE WITH QUALIIFYING CRITERIA OR TERM OF SERVICE

If at any time during the term of the Rider agreement the Customer violates the terms and conditions of the Rider or the Service Agreement, the Company may discontinue the discount provided for under this Rider and bill the Customer based on their applicable rate schedule. If the Customer terminates service prior to the end of the Agreement period or fails to meet the Qualifying Criteria agreed to for the term of the Agreement, this will constitute a violation of the terms and conditions of the Rider and Agreement.

Should service under this Rider be discontinued by the Company or Customer for said violation, the Customer shall be required to repay to the Company the amount of the cumulative discounts received under this Rider in accordance with the following schedule.

Number of months beginning with and following the effective date declaration and ending with the date of violation	Required percentage of cumulative economic development bill discounts that must be repaid
Month 1 to end of credits	100%
First 12 months after credits cease	80%
Months 13-24 after credits cease	60%
Months 25-36 after credits cease	40%
Months 36-47 after credits cease	20%
Month 48 to term of contract	10%

If a change in ownership occurs after execution of the Service Agreement, the successor Customer may, in the Company's discretion, be allowed to fulfill the balance of the Service Agreement and participate in this Rider.

RIDER NSC
NON-RESIDENTIAL SOLAR CHOICE

AVAILABILITY

Available to non-residential Customer-Generators receiving concurrent service from the Company, on a metered rate schedule, except as indicated under General Provisions. A Customer-Generator is an owner, operator, or lessee of an electric generation unit that generates or discharges electricity from a renewable energy resource, including an energy storage device configured to receive electrical charge solely from an onsite renewable energy resource. The renewable net energy metered (NEM) generation, which may include a solar photovoltaic; solar thermal; wind powered; hydroelectric; geothermal; tidal or wave energy; recycling resource; hydrogen fueled or combined heat and power derived from renewable resources; or biomass fueled generation source of energy, must be installed on the Customer's side of the delivery point, for the Customer's own use, interconnected with and operated in parallel with the Company's system. The generation must be located at a single premise owned, operated, leased or otherwise controlled by the Customer. The system may either be owned by the Customer or by a lessor and leased to the Customer.

Customers applying for service under this Rider must be served under an approved general service or industrial rate schedule that includes time-of-use (TOU) periods.

If Customer receives electric service under a schedule other than a TOU schedule with demand rates, any renewable energy credit or "green tags" shall be provided by Customer at no cost to Company. If service is received under a time-of-use schedule with demand rates, all renewable energy credits or "green tags" shall be retained solely by Customer.

GENERAL PROVISIONS

1. To qualify for service under this Rider, the Customer must comply with all applicable interconnection standards and must provide, in writing, the Nameplate Capacity of the Customer's installed renewable generation system. Any subsequent change to the Nameplate Capacity must be provided by Customer to Company in writing by no later than 60 days following the change.

2. To qualify for service under this Rider, the Customer must not be served on another parallel generation rate schedule or rider. For Customer-owned facilities, the Nameplate Capacity of Customer's installed renewable generation system and equipment must not exceed the lesser of 5,000 kW AC or 100% of the Customer's contract demand which shall approximate the Customer's maximum expected demand. For leased facilities, the Nameplate Capacity of Customer's installed renewable generation system and equipment must not exceed the lesser of 1,000 kW AC or 100% of the Customer's contract demand which shall approximate the Customer's maximum expected demand.

3. If the Customer is not the owner of the premises receiving electric service from the Company, the Company shall have the right to require that the owner of the premises give satisfactory written approval of the Customer's request for service under this Rider.

4. If the electricity supplied to the Customer by the Company exceeds the electricity delivered to the grid by the Customer-Generator during a monthly billing period, the Customer-Generator shall be billed for the net electricity in kWh supplied by the Company plus any demand or other charges under the applicable rate schedule or riders.

5. If the electricity delivered to the grid by the Customer-Generator exceeds the electricity supplied by the Company during a monthly billing period, the Customer-Generator shall be credited for the net excess energy in kWh generated during that billing period at the Monthly Credit rate below.

6. Net electricity will be calculated for each TOU period, in descending order by price. Any net excess energy from one TOU period will be applied to the next TOU period, as applicable. After net electricity has been calculated for all TOU periods, the Customer-Generator shall be credited for any remaining net excess energy at the Monthly Credit rate below.

7. In the event the Company determines that it is necessary to increase the capacity of facilities beyond those required to serve the Customer's electrical requirement or to install a dedicated transformer or other equipment to protect the safety and adequacy of electric service provided to other customers, the Customer shall pay the estimated cost of the required transformer or other equipment above the estimated cost which the Company would otherwise have normally incurred to serve the Customer's electrical requirement, in advance of receiving service under this Rider.

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8. A Standby Charge of $1.85 per kW per month shall apply to customers with a generation system larger than 100 kW, excluding customers served under a TOU demand rate schedule with a generation system with less than 60% planning capacity factor as determined by the Company. If applicable, the Standby kW will be the Nameplate Rating of the Customer's generation system.

RATE

All provisions of the applicable schedule and other applicable riders will apply to service supplied under this Rider, except as modified herein. In addition to all charges in the applicable rate schedule for Customer's net electrical usage, the following credit will be applied to net electricity delivered to the grid by Customer's renewable generation as specified under General Provisions:

Monthly Credit for Net Excess Energy, per kWh $0.0335

METERING REQUIREMENTS

The Company will furnish, install, own and maintain a billing meter to measure the kW demand delivered by the Company to the Customer, and to measure the net kWh purchased by the Customer or delivered to the Company. For renewable generation capacity of 20 kW AC or less, the billing meter will be a single, bi-directional meter which records independently the net flow of electricity in each direction through the meter, unless Customer's overall electrical requirement merits a different meter. For larger renewable generation capacities, the Company may elect to require two meters with 30-minute interval capabilities to separately record Customer's electrical consumption and the total generator output, which will be electronically netted for billing. The Customer grants the Company the right to install, operate, and monitor special equipment to measure the Customer's generating system output, or any part thereof, and to obtain any other data necessary to determine the operating characteristics and effects of the installation. All metering shall be at a location that is readily accessible by the Company.

SAFETY, INTERCONNECTION AND INSPECTION REQUIREMENTS

This Rider is only applicable for installed generation systems and equipment that comply with the provisions outlined in the North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections (hereinafter "Interconnection Procedures") as approved by the North Carolina Utilities Commission.

The Customer must submit a Request to Interconnect, which must be accepted by the Company, pay an application fee, comply with the liability insurance requirements of the Interconnection Procedures and enter into a specific contract providing for interconnection to the Company's system.

In order to ensure protection of the Company's system, the Company reserves the right, at its discretion, to inspect the Customer's generation system and equipment at any time upon reasonable notice to the Customer in an effort to ensure compliance with the Interconnection Procedures. The Company reserves the right to disconnect electric service to the premises if the Company determines that the Customer's generation system and equipment is not in compliance with the Interconnection Procedures and is being operated in parallel with the Company's system.

The Customer shall be responsible for any costs incurred by the Company pursuant to the Interconnection Procedures. The Company reserves the right to require additional interconnection facilities, furnished, installed, owned and maintained by the Company, at the Customer's expense, if the Customer's system, despite compliance with the Interconnection Procedures, causes safety, reliability or power quality problems. These additional facilities will be subject to a monthly charge under the Extra Facilities provisions of the Company's Service Regulations provided, however, that the minimum Extra Facilities Charge shall not apply.

POWER FACTOR

When the average monthly power factor of the power supplied by the Customer to the Company is less than 90 percent or greater than 97 percent, the Company may correct the energy in kWh, as appropriate. The Company reserves the right to install facilities

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necessary for the measurement of power factor. The Company will not install such equipment, nor make a power factor correction if the generation system is less than 20 kW and uses an inverter.

CONTRACT PERIOD

The Customer shall enter into a contract for service under this Rider for a minimum original term of one (1) year, and the contract shall automatically renew thereafter, except that either party may terminate the contract after one year by giving at least 60 days prior notice of such termination in writing.

The Company reserves the right to terminate the Customer's contract under this Rider at any time upon written notice to the Customer in the event that the Customer violates any of the terms or conditions of this Rider, or operates the renewable generation system and equipment in a manner which is detrimental to the Company or any of its customers. In the event of early termination of a contract under this Rider, the Customer will be required to pay the Company for the costs due to such early termination, in accordance with the Company's Service Regulations.