BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1300

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**JONATHAN L. BYRD**
For Adjustment of Rates and Charges Applicable	)	**FOR DUKE ENERGY**
to Electric Service in North Carolina and	)	**PROGRESS, LLC**
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 Progress, LLC ("DEP" 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-2, Sub 1262.

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 Carolinas, LLC ("DEC").

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 new Hourly Pricing Schedule (Schedule HP), High Load Factor Schedule (Schedule LGS-HLF), Economic Development Rider (Rider EC), and 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 DEP'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-2, Sub 1219, 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-2, Sub 1219. 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 DEP'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 Teresa Reed. 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 and non-residential customers. 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 Residential TOU Demand Rate;
- New Hourly Pricing Tariff;
- New High Load Factor ("HLF") Tariff; 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 Reed will provide further details on the specific pricing and design elements of the existing and new or redesigned tariffs.

II. TOU PERIOD CHANGES

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 can 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 two of the Company's current tariffs, R-TOU-CPP and SGS-TOU-CPP. These rates were approved in Docket Nos. E-2, Sub 1219 and E-2, Sub 1280 and became effective March 1, 2022.

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 SGS-TOU-CPP) and Residential Service (Schedule R-TOU-CPP) 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.

Step 2: 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.

Step 3: 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 3-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 CH-TOUE, GS-TES, and APH-TES.

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

A. The impacted rate schedules would include R-TOU, the redesigned R-TOUD, SGS-TOUE, SGS-TOU (which the Company proposes to rename "MGS-TOU" as discussed in Witness Reed's testimony), LGS-TOU, LGS-RTP, and the Large Load Curtailable Rider LLC. Schedules R-TOU-CPP and SGS-TOU-CPP 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 R-TOUD Rate with Two-Part Demand

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REVISION TO ITS R-TOUD SCHEDULE.

A The Company proposes to revise the R-TOUD rate schedule based upon the new TOU periods, as discussed above. In addition, the Company is proposing that the demand structure for R-TOUD 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 time 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.

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).

- 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 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 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 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 SCHEDULES WILL BE AFFECTED BY THE CHANGE TO THE DEMAND CHARGE STRUCTURE FOR NON-RESIDENTIAL CUSTOMERS?

A. The impacted rate schedules would be SGS-TOU (renamed MGS-TOU) and LGS-TOU. The new demand charge structure also has the benefit of eliminating the need for the minimum bill provision for the renamed MGS-TOU tariff.

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 Reed is proposing pricing which reflects slightly higher recovery through demand charges for TOU rates.

B. Reduce 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. First, the rider requires that all future NEM customers be served under a general service 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"). Additionally, and as referenced in Witness Reed's testimony, the Company is proposing to eliminate the standby charge for customers with a planning capacity factor 60% or lower (as contained in the Company's proposed changes to Rider SS). 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 October 1, 2023 and allow existing NEM customers to continue service under Rider NM until they request service under Rider NSC or until September 30, 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 May 31. The Company proposes to change the reset date to April 30 to correspond with the beginning of the summer season as defined going forward in the Company's proposed TOU rates.

D. New Hourly Pricing Tariff

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

A. During the CRDS, stakeholders expressed an interest in a more flexible marginal price rate with expanded availability. The Company's existing LGS-

RTP rate is administratively burdensome and presently limited to participation by 85 customers and therefore cannot accommodate the expansion and changes contemplated.

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

A. The proposed Hourly Pricing rate will provide broader access for customers to marginal pricing. However, the new tariff will have features that encourage customers to be consistently price-responsive during times of grid constraints to retain access to marginal pricing. Byrd Exhibit 7 includes a tariff sheet showing the mechanics behind the new rate. This tariff will be available to all customers with load greater than 1,000 kW, similar to the current availability of LGS-RTP. 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 the hourly energy prices described in the proposed HP Rate. 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 reduced 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 proposes to follow DEC's process of CBL management, which is average kW and kWh by TOU period, eliminating the need for the administratively burdensome calendar mapping and special days process currently in use for the existing RTP rate. 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, the proposed rate allows for greater exposure to marginal prices, provided customers demonstrate price-responsiveness during grid events. Notably, the Company is proposing the rate without a participation cap due to the durability and scalability of the new program design.

E. Freeze LGS-RTP Rate

Q. PLEASE DESCRIBE THE LGS-RTP RATE.

A. LGS-RTP is a historic rate that provides exposure to marginal prices but was restricted to participation by a maximum of 85 non-residential customers. The existing LGS-RTP rate is administratively burdensome and does not contain ongoing CBL adjustments, creating scalability issues by allowing incremental load to remain on marginal pricing indefinitely.

Q. WHY IS THE COMPANY PROPOSING TO FREEZE THE LGS-RTP RATE?

A. The newly proposed HP Tariff will provide expanded access to marginally priced energy for Large General Service customers. Because the LGS-RTP tariff is not scalable, the Company believes it is appropriate to freeze LGS-RTP. As mentioned above, the new tariff contains important provisions supporting wider availability and more flexible CBLs than the existing RTP rate and is less administratively burdensome. Further, the new tariff encourages price-responsiveness at times of grid constraints, a feature benefitting all customers by encouraging lower peak system demands. With the advent of the new HP Tariff, the Company proposes to freeze the LGS-RTP rate and not allow additional customers onto the rate. The Company proposes to keep the current LGS-RTP tariff open only to customers served on that tariff prior to availability of the new HP Tariff (i.e., grandfather existing customers).

Q. ARE ANY OTHER CHANGES PROPOSED FOR THE LGS-RTP RATE?

A. Yes. We are proposing to replace the Adder within the Hourly RTP Rate with an Incentive Margin charge applied on a monthly basis for net load above the CBL. The Incentive Margin serves the same purpose as the Adder but is consistent with both DEC's Hourly Pricing for Incremental Load Tariff as well as the proposed new HP Tariff. The proposed Incentive Margin rate is in line with historical RTP Adder rates, so LGS-RTP customers will not experience a material impact on their bills from this structural pricing change. Importantly, the Incentive Margin rate will be transparent and defined in the tariff. As a result of this change, incremental kWh usage for both LGS-RTP and the proposed HP Tariff will be consistently priced.

F. 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 provides varying credit levels based on load factor but offers little flexibility otherwise. The Company's proposed new Economic Development Rider, Rider EC, 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 EC 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 500kW (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 EC contains several improvements, including the following:

- **Flexible Benefits** – The current Rider ED 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 EC 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 current Rider ED 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 current Rider ED provides benefits that steadily decline over a five-year period on a rigid schedule. The proposed Rider EC 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 ED provides a reduction in demand charges that must be modified to account for the redesigned demand charge structure described earlier in my testimony. Accordingly, the proposed Rider EC 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 EC 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 EC 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 EC participants, thereby continuing to protect non-participants from such exposures. Importantly, Rider EC 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 EC 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 ED) AND ECONOMIC REDEVELOPMENT RIDER (RIDER ERD) TO NEW APPLICANTS?

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

G. 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, LGS-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 LGS-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 LGS class tariffs. Additionally, demand charges are based on a billing demand defined as the greater of (1) the highest demand in the billing month, or (2) 90% of the highest demand during the preceding 11 months. 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?

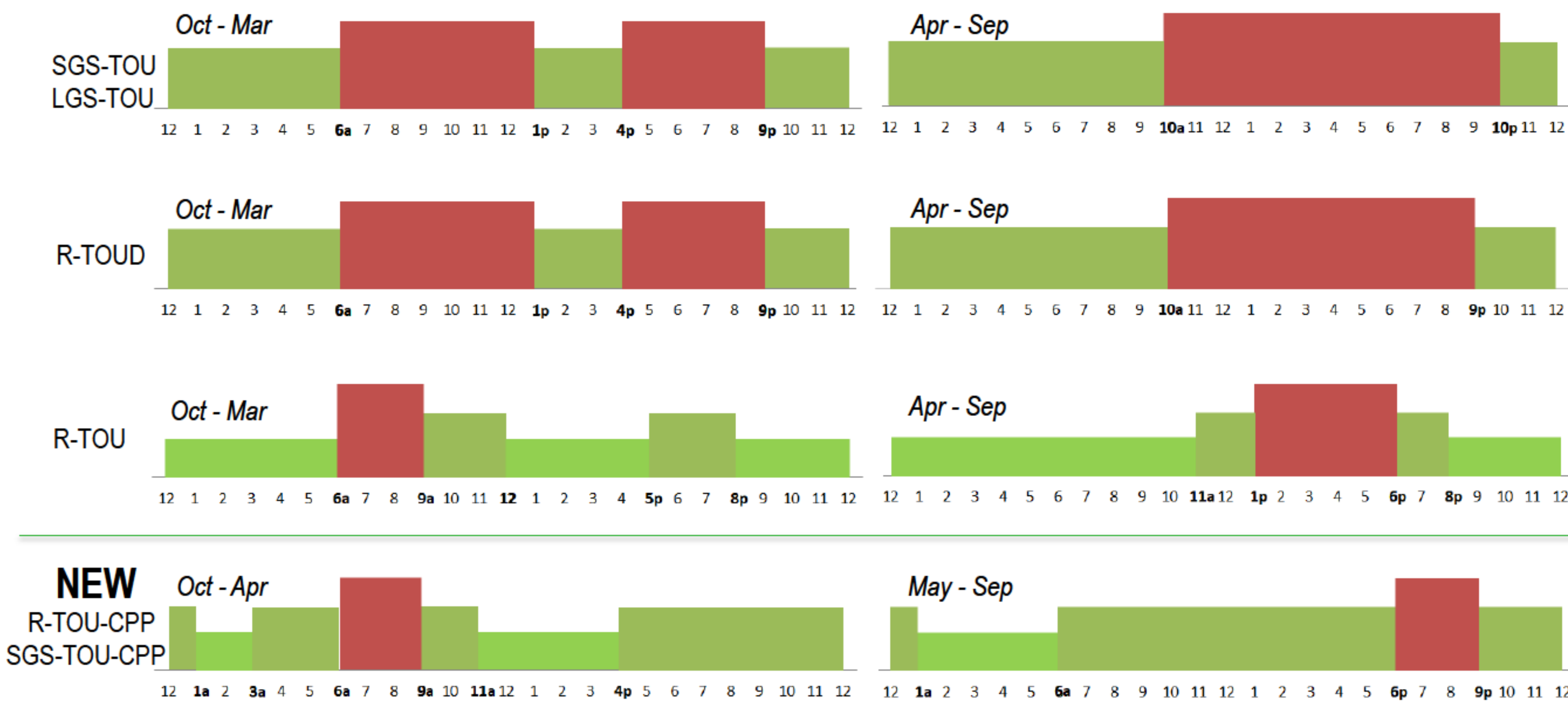
A. No. The rate does not explicitly limit participation to customers with high load factors but rather uses the pricing design to limit the attractiveness of the rate to such customers. In other words, while the rate is generally available to customers who meet the qualifications for LGS tariffs, the 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?

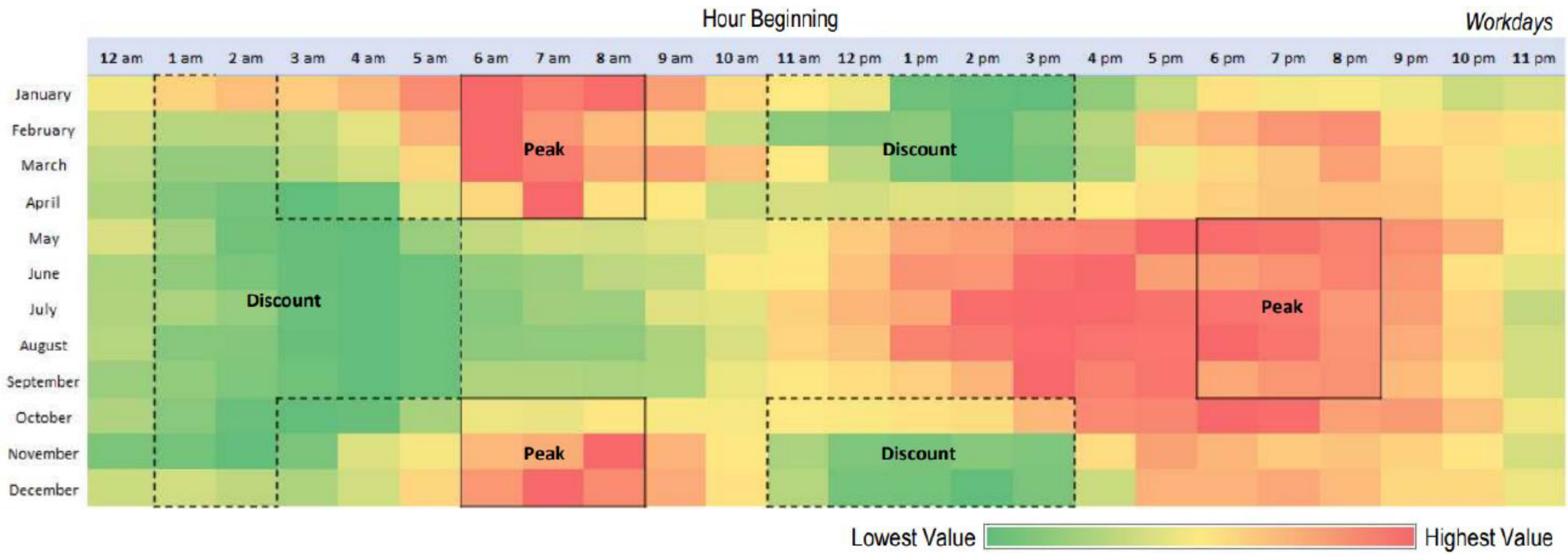
A. Yes.

DEP-NC TOU Period Comparison



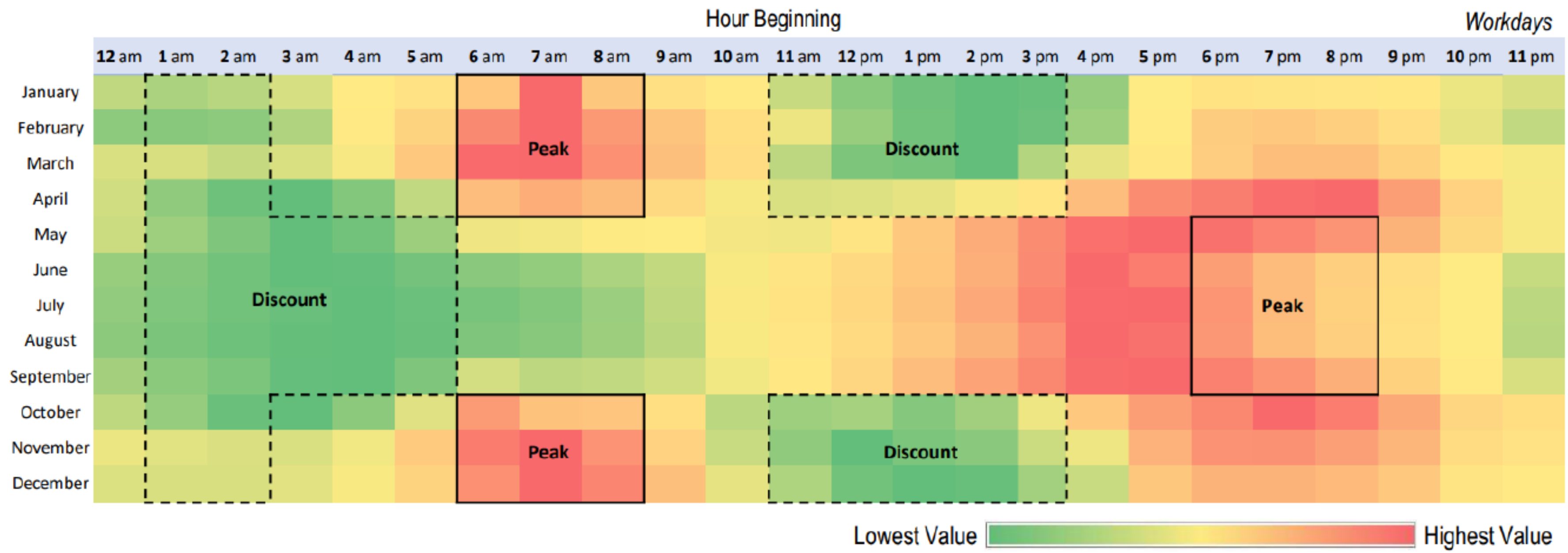
The Company proposes using the pricing periods for the recently approved Critical Peak Pricing rates across the Company's other major tariffs.

TOU Period and Marginal Energy Costs (2018-2020)



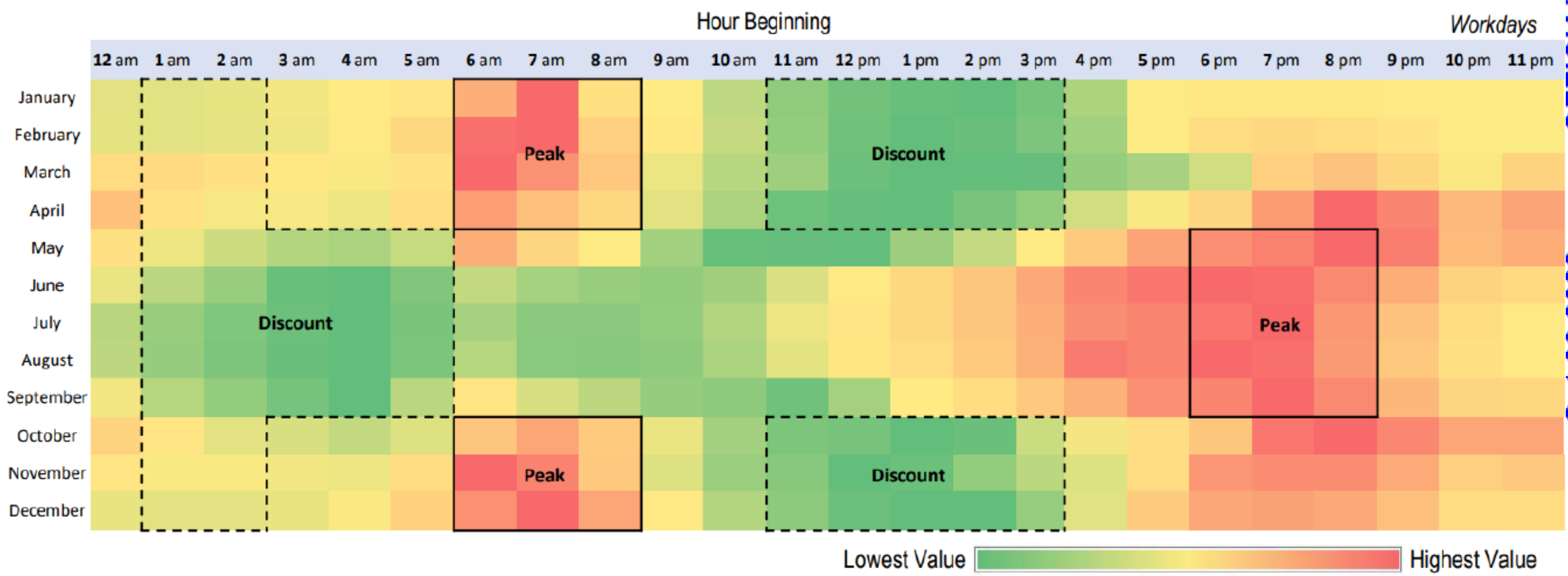
Historical view of actual Marginal Energy Cost aligns with discount and peak-periods

Cost Duration Model: **2021**



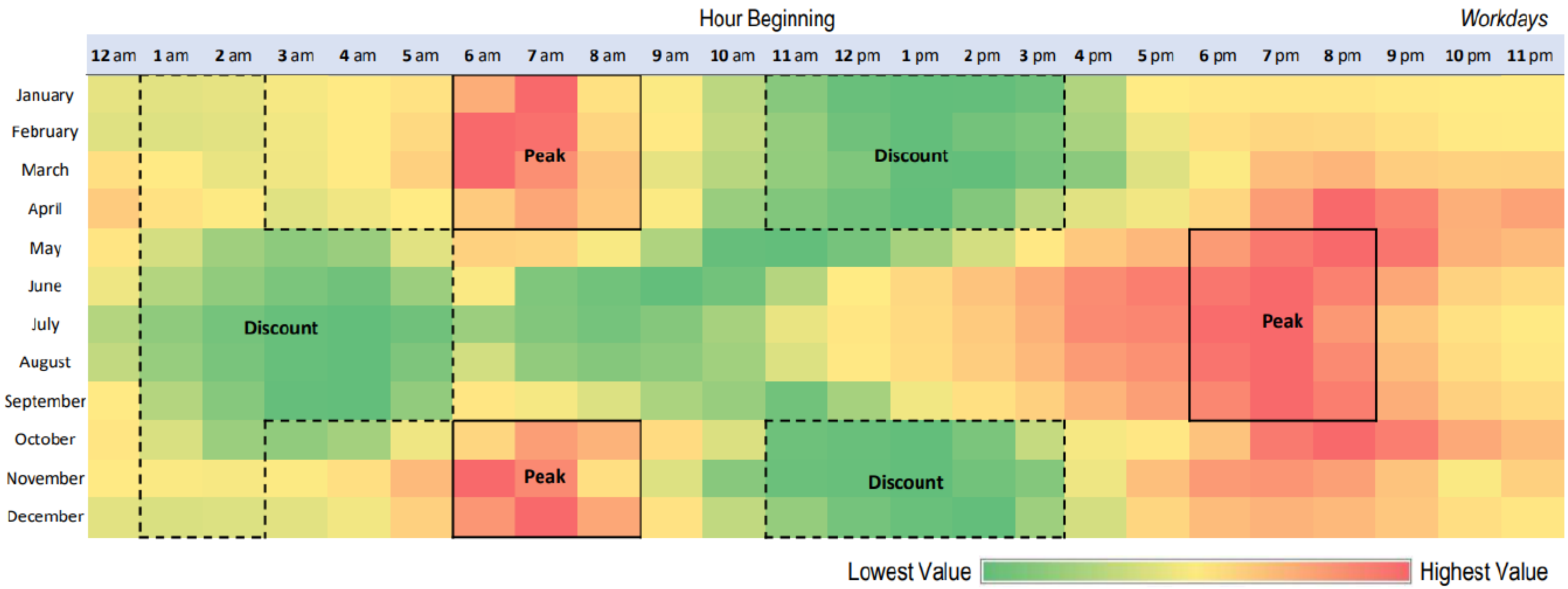
- Relative pricing on an intra-month basis, with hours compared to other hours in that same month only
- Cost Duration Model provides weighted-average view of cost of service
- Discount and winter peak periods align with costs in 2021-2030
- Summer peak shifts later in the evening from 2021-2030 due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

Cost Duration Model: **2026**



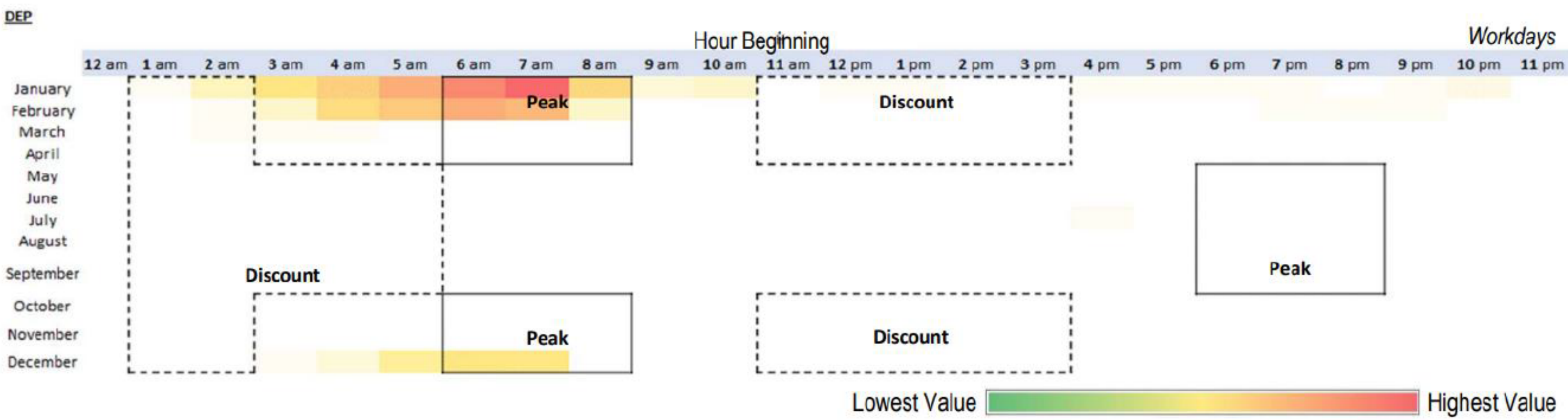
- Summer peak aligns with proposed peak period beyond 2025
- Winter mid-day costs decline on a relative basis, while costs remain low for overnight discount period

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

HOURLY PRICING
SCHEDULE HP

AVAILABILITY

This Schedule is available, at the Company's option, for electric service to non-residential customers with a Contract Demand that equals or exceeds 1,000 kW. Customer must be eligible for service under Schedule LGS or LGS-TOU for their baseline load.

This Schedule is not available: (1) for short-term or temporary service; (2) for electric service in conjunction with Incremental Power Service Rider IPS and Dispatched Power Rider No. 68; (3) for electric service in conjunction with Large Load Curtailable Rider LLC, or Economic Development Rider EC, except as provided for in the Baseline Charge; (4) to a customer who had discontinued receiving service under this Schedule, or its predecessor, during the previous 12 months; or (5) for any new customer with a Contract Demand in excess of 50,000 kW. 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 Company, except at the option of Company, under special terms and conditions expressed in writing in the contract with Customer. Customer shall be required to furnish and maintain a communication link and equipment suitable to support remote reading of Company's meter serving Customer and to support daily receipt of Hourly Prices.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, three-phase 3 or 4 wires, at Company's standard voltages of 480 volts or higher. When Customer desires two or more types of service, which types can be supplied from a three-phase 4 wire type, without voltage transformation, only the type of service necessary for Customer's requirements will be supplied under this Schedule.

MONTHLY RATE

The monthly rate 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 = $2.84 per kW of Incremental Demand for Distribution Service
= $1.87 per kW of Incremental Demand for Transmission Service

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 minus Reduced Load.

Incremental Demand: Incremental Demand (kW) is the amount by which actual kW (maximum integrated 15-minute demand during the month for which the bill is rendered) exceeds CBL kW for the same 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 calendar 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.

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 LGS-HP or LGS-RTP. 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.

VII. 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.

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.

VIII. Rider Adjustments

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. 601	Rider BA**
Leaf No. 602	Rider JAA*
Leaf No. 603	Rider EDIT-3*
Leaf No. 604	Rider EDIT-4*
Leaf No. 605	Rider CPRE

*Riders JAA, EDIT-3, and EDIT-4 are not applicable to the Net New Load kWh usage.
**The DSM/EE component of Rider BA is applicable to incremental kWh usage if the customer is opted-in to the DSM/EE charges. The base fuel, fuel adjustment, and EMF rates are not applicable to the incremental kWh usage.

IX. Customer Affordability Rider (CAR)

The monthly bill shall include a CAR Adjustment (Leaf No. 611) to fund the Customer Affordability Program Credit Program for residential customers that qualify for the Low Income Energy Assistance Program (LIEAP) or Crisis Intervention Program (CIP) as is further explained in Leaf No. 718.

X. Storm Securitization Charge:

A Storm Securitization charge will be added to the monthly bill based on the currently approved cents/kWh incremental rate as shown in the Storm Securitization Rider (Leaf No. 607 Rider STS).

XI. Renewable Energy Portfolio Standard (REPS) Adjustment:

The monthly bill shall include a REPS Adjustment based upon the revenue classification. Upon written request, only one REPS Adjustment shall apply to premises serving the same customer for all accounts of the same revenue classification. If a customer has accounts which serve in an auxiliary role to a main account on the same premises, no REPS charge should apply to the auxiliary accounts regardless of their revenue classification (see Leaf No. 601 Annual Billing Adjustments Rider BA).

PROVISION OF STANDBY SERVICE

If service is received under a standby service tariff prior to service under this Schedule, the use of standby service shall be excluded from initial determination and update of the CBL. The Baseline Charge, as set forth in the Monthly Rate section above, shall include billing of Supplementary Service but shall not include any charges related to reservation or use of Standby Service. The Monthly Rate provisions of the applicable standby service tariff shall be calculated assuming no standby service was used. Any use of Standby Service will be billed pursuant to the Energy Charge provisions of this Schedule. All other provisions of the applicable standby service tariff apply.

SALES TAX

To the above charges will be added any applicable North Carolina Sales Tax.

PAYMENT

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, the Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Term shall be monthly and will be automatically renewed unless terminated by either party by giving not less than thirty (30) days written notice of termination.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations and any changes therein, substitutions therefore, or additions thereto lawfully made.

Where Customer's other source of power is connected electrically or mechanically to equipment which may be operated concurrently with service supplied by Company, Customer shall install and maintain at his expense such devices as may be necessary to protect his equipment and service and to automatically disconnect his generating equipment, which is operated in parallel with Company, when service used by Customer is affected by electrical disturbances on Company's or Customer's systems. Should Company determine that Customer's facilities are not adequate to protect Company's facilities, Company may install the necessary facilities and Customer shall pay for the extra facilities in accordance with Company's Service Regulations.

Company makes no representation regarding the benefits of Customer subscribing to this Schedule. Customer, in its sole discretion, shall determine the feasibility and benefits of Customer subscribing to this Schedule.

LARGE GENERAL SERVICE
(HIGH LOAD FACTOR)
SCHEDULE LGS-HLF

AVAILABILITY

This Schedule is available for electric service used by a nonresidential customer with either a Contract Demand that equals or exceeds 1,000 kW or whenever the registered or computed demand equals or exceeds 1,000 kW in the preceding 12 months.

This Schedule is not available: (1) for breakdown, standby, or supplementary service unless used in conjunction with the applicable standby or generation service rider for a continuous period of not less than one year; (2) for resale service; (3) for electric service in conjunction with Incremental Power Service Rider IPS, Dispatched Power Rider No. 68, Standby & Supplementary Service Rider No. 7, or Supplementary & Interruptible Standby Service Rider No. 57; (4) for electric service in conjunction with Large General Service (Real Time Pricing) Schedule LGS-RTP; or (5) for any new customer with a Contract Demand in excess of 100,000 kW.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, three-phase 3 or 4 wires, at Company's standard voltages of 480 volts or higher or the voltage at which Customer was being served on September 24, 1982. When Customer desires two or more types of service, which types can be supplied from a three-phase 4 wire type, without voltage transformation, only the one of these two types necessary for Customer's requirements will be supplied.

CONTRACT DEMAND

The Contract Demand shall be the kW of demand specified in the Service Agreement.

MONTHLY RATE

I. Basic Customer Charge:

$210.00

II. kW Demand Charge:

$26.95 per kW of Billing Demand

III. kWh Energy Charge:

2.513¢ per kWh

IV. Riders

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. 601	Rider BA
Leaf No. 602	Rider JAA
Leaf No. 603	Rider EDIT-3
Leaf No. 604	Rider EDIT-4
Leaf No. 605	Rider CPRE

V. Renewable Energy Portfolio Standard (REPS) Adjustment:

The monthly bill shall include a REPS Adjustment based upon the revenue classification. Upon written request, only one REPS Adjustment shall apply to premises serving the same customer for all accounts of the same revenue classification. If a customer has accounts which serve in an auxiliary role to a main account on the same premises, no REPS charge should apply to the auxiliary accounts regardless of their revenue classification (see Leaf No. 601 Annual Billing Adjustments Rider BA).

VI. Transformation Discounts:

When Customer owns the step-down transformation and all other facilities beyond the transformation which Company would normally own, except Company's metering equipment, the charge per kW of Billing Demand and per kWh will be reduced in accordance with the following:

Transmission Service Transformation Discount	Distribution Service Transformation Discount
\$0.98/kW	\$0.64/kW
\$0.00017/kWh	\$0.00007/kWh

Transmission: For Customer to qualify for the Transmission Service Transformation Discount, Customer must own the step-down transformation and all other facilities beyond the transformation which Company would normally own, except Company's metering equipment, necessary to take service at the voltage of the 69 kV, 115 kV, or 230 kV transmission line from which Customer received service.

Distribution: For Customer to qualify for the Distribution Service Transformation Discount, Customer must own the step-down transformation and all other facilities beyond the transformation which Company would normally own, except Company's metering equipment, necessary to take service from the distribution line of 12.47 kV or higher from which Customer receives service. The distribution service source must be from a general distribution line and must be from other than a transmission-to-distribution substation built primarily for Customer's use in order to qualify for the Distribution Service Transformation Discount. A general distribution line is a 12.47 kV or higher voltage distribution line built to serve the general area and not built primarily to serve a specific customer.

Company shall have the option to install high-side metering equipment or low-side metering equipment compensated for Customer-owned transformer and line losses.

Any facilities which Company provides above those which Company would normally have utilized to service Customer's Contract Demand shall be considered as Extra Facilities. Any Company-owned protection system installed when service is directly from Company's 69 kV, 115 kV, or 230 kV transmission system or a distribution line of 12.47 kV or higher shall be considered Extra Facilities.

If changing conditions on Company's electrical system make continuation of the current delivery voltage impractical, Customer shall be responsible for all costs for the conversion beyond the point of delivery except any Company-owned metering equipment. At the time of the conversion, Company reserves the right to provide service at one of its available voltages.

If subsequent changes in the use of Company's facilities occur which cause the reclassification of either transformers or lines, Customer's entitlement to the discount may be changed.

VII. Minimum Bill:

The minimum monthly charge shall be the Basic Customer Charge plus the REPS Adjustment plus a charge for 1,000 kW.

VIII. Customer Affordability Rider (CAR)

The monthly bill shall include a CAR Adjustment (Leaf No. 611) to fund the Customer Affordability Program Credit Program for residential customers that qualify for the Low Income Energy Assistance Program (LIEAP) or Crisis Intervention Program (CIP) as is further explained in Leaf No. 718.

IX. Storm Securitization Charge:

A Storm Securitization charge will be added to the monthly bill based on the currently approved cents/kWh incremental rate as shown in the Storm Securitization Rider (Leaf No. 607 Rider STS).

DETERMINATION OF BILLING DEMAND

The Billing Demand shall be the maximum kW registered or computed, by or from Company's metering facilities, during any 15-minute interval within the current billing month. However, the Billing Demand shall not be less than the greater of: (1) 90% of the maximum monthly 15-minute demand during the preceding 11 billing months, or (2) 75% of the Contract Demand until such time as the Billing Demand first equals or exceeds the effective Contract Demand, or (3) 1,000 kW.

POWER FACTOR ADJUSTMENT

When the power factor in the current billing month is less than 85%, the monthly bill will be increased by a sum equal to $0.32 multiplied by the difference between the maximum reactive kilovolt-amperes (kVAr) registered by a demand meter suitable for measuring the demands used during a 15-minute interval and 62% of the maximum kW demand registered in the current billing month.

SALES TAX

To the above charges will be added any applicable North Carolina Sales Tax.

PAYMENTS

Bills are due when rendered and are payable within 25 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year; except for short-term, construction or temporary service, the Contract Period may be for the period requested by Customer and in such event Customer agrees:

1. That the service supplied shall be for a continuous period until disconnected; and

2. That where it is necessary for Company to extend lines, erect transformers, or do any work necessary to supply service, Customer shall pay for the line extension in accordance with Line Extension Plan E.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

ECONOMIC DEVELOPMENT
RIDER EC

AVAILABILITY

Available, only at Company's option, to nonresidential establishments receiving service under Company's Large General Service or Large General Service (Time-of-Use) Schedules provided that the establishment is not classified as Retail Trade or Public Administration by the Standard Industrial Classification (SIC) Manual published by the United States Government. This Rider is not available for Large General Service (Real Time Pricing).

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 Rider ED 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; (3) electrical load that results from the shutdown or reduction of generation facilities; or (4) service in conjunction with Transition Rider TR-1.

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, standby, dispatched power, or incremental power 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 thirty-six (36) months after the Delivery Date.

Month

The term "month" as used in this Rider means the period intervening between readings for the purpose of monthly billings. Readings will be collected each month at intervals of approximately thirty (30) days.

QUALIFYING CRITERIA

To participate in this Rider, the customers 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 1,000kW at 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. See New Load section above.
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 fifty (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 five hundred thousand dollars ($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.
D. The two (2) new FTE employees in item B.2) and the minimum load factor of 40% requirements in item A above are waived for EV Fleet Customers, where 80% of expected energy usage is related to EV charging. Additionally, the minimum qualifying New Load Requirement of 1,000kW is lowered to 500kW for EV Fleet. 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 full-time equivalent employees (FTE) 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 Large General Service and Large General Service (Time-of-Use)

Schedules applicable to the individual customer 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 otherwise applicable General Service Tariff 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 or expanded load:

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

The third criterion, Company's incremental costs to serve the New Load, 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 Operational Date as an effective date of this rider which is no more than thirty-six (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 following the customer's effective date, with the bill reductions being available for a maximum period of ten (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 the otherwise applicable General Service Tariff. 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 the 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:
Months 1-End of Credit Month	100%
First 12 Months after credit 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-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.

NON-RESIDENTIAL SOLAR CHOICE
RIDER NSC

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 includes 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 existing approved general service rate schedule that includes time-of-use periods.

If Customer receives electric service under a schedule other than a time-of-use 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, Customers must be served on an approved general service rate schedule, but must not be served on Schedules GS-TES, APH-TES, TSS, TFS, LGS-RTP, LGS-HLF, HP, CSE, SFLS, SGS-TOU-CLR, or another parallel generation 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 kilowatt-hours (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.
8. Standby Service provisions shall not be required when service is used in conjunction with this Rider for generation capacities of 100 kW or less.

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 $0.0340

METERING REQUIREMENTS

Company will furnish, install, own and maintain a billing meter to measure the kilowatt demand delivered by Company to Customer, and to measure the net kWh purchased by Customer or delivered to 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 15-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 renewable generation systems and equipment that complies with and meets all safety, performance, interconnection, and reliability standards established by the Commission, the National Electric Code, the National Electrical Safety Code, the Institute of Electrical and Electronic Engineers, Underwriter's Laboratories, the Federal Energy Regulatory Commission and any local governing authorities. Customer must comply with all liability insurance requirements of the Interconnection Standard.

POWER FACTOR

The Customer's renewable generation must be operated to maintain a 100% power factor, unless otherwise specified by Company. When the average monthly power factor of the power supplied by the Customer to the Company is other than 100%, the Low Power Factor Adjustment stated in the Company's Service Regulations may be applicable. The Company reserves the right to install facilities necessary for the measurement of power factor. The Company will not install such equipment, nor charge a Low Power Factor Adjustment if the renewable generation system is less than 20 kW AC 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 sixty (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 South Carolina Service Regulations.