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Mar 31 2022

March 31, 2022

**VIA ELECTRONIC FILING**

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

**RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Rate Design Study Roadmap**
**Docket Nos. E-7, Sub 1214 and E-2, Sub 1219**

Dear Ms. Dunston:

Pursuant to the North Carolina Utilities Commission's March 31, 2021 *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* in Docket No. E-7, Sub 1214 and its April 16, 2021 *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* in Docket No. E-2, Sub 1219, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (collectively "Duke Energy") enclose for filing in the above-referenced dockets Duke Energy's Comprehensive Rate Design Study roadmap and timeline for proposing new rate designs and identifying areas for additional study.

If you have any questions, please do not hesitate to contact me. Thank you for your attention to this matter.

Sincerely,

Jack E. Jirak

Enclosure

cc: Parties of Record

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# Comprehensive Rate Design Study Roadmap

## Duke Energy

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# 1 Executive Summary

Rate design modernization options present valuable opportunities for North Carolina, including customers of all classes. Pricing and rate design seek to achieve multiple goals that must be carefully balanced. Rate design must collect the revenue requirements of the Companies in a manner that is not unduly discriminatory while also encouraging beneficial consumption patterns to improve system efficiency and keep costs low for all customers. Accordingly, rate design often involves complicated tradeoffs that must consider both system dynamics and wide-ranging differences across customer classes and individual customers, particularly when considering varying levels of energy technology adoption. Several factors led to the intensive rate design review, including:

- Technology Support – The Companies' investments in smart meters, data analytics capabilities, and a new billing system enable more potential options for creative and tailored rate designs to match increasingly diverse customer expectations. Not only is data more available than ever before, but we can now extract actionable insights and have the sophisticated tools necessary to implement improvements based on the findings.
- Desire for Options – Customers desire and expect more pricing options and more control over energy costs.
- Grid Dynamics – The electric grid is becoming more complex and dynamic with the current energy transition, and solutions must include both supply-side and demand-side considerations, including novel pricing approaches.

Importantly, rate design must be customer-centric. An elegantly designed rate with novel pricing features but with zero participation or interest from customers is worthless – thus, customer ideas and constructive dialogue are necessary to developing and improving rate designs that will achieve the intended purposes. The findings and ideas from the Comprehensive Rate Design Study and included in the following Roadmap are the product of concentrated and collaborative efforts from numerous stakeholders over the past 12 months. While not all ideas can be expected to garner full consensus or support, future filings and applications for rate design changes will flow from the discussions and tradeoff analysis in the Comprehensive Rate Design Study, which included:

- Participation from more than 50 organizations including commercial and industrial (C&I) customers, EV companies and advocates, environmental advocates, government agencies, public advocates, renewable/distributed energy resource (DER) companies, and legal/consulting companies.
- Communication facilitated by a third party (ICF) including two-way dialogue, broad information sharing with focused discussions on particular topics, technology-enabled interactive brainstorming sessions, with directions and priorities informed by stakeholder surveys.
- Investigation into rate design questions and pricing elements using big data techniques on questions pertinent to diverse rate design ideas suggested by the collaborative.

Finally, the effort focused on actionable outcomes with the potential for meaningful impacts. The investigations and analytics demonstrated that Duke Energy's historic rates were well-founded and provided fair apportionment of costs with satisfactory price signals, but which should be updated to address increasing levels of distributed energy technology adoption and use of intermittent resources. Major findings from the study include:

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- Duke Energy's current rate designs demonstrate good alignment to cost-causation for the major customer classes across factors such as size and load factor. Historic rates were well designed, fairly apportioned costs, and reflected historic system dynamics.
- Enabling beneficial growth and economic development, including electric vehicles, and equitable outcomes given increasing levels of energy technology adoption (e.g. solar, storage) requires more sophisticated rate designs that recognize both current and expected system changes.
- Some improvements are possible immediately (some program or rate design tariff filings have occurred during the course of the study), but others will require holistic design considerations and are best addressed in the context of rate case filings.
- The following Roadmap demonstrates the success of the collaborative approach at recognizing, organizing, and prioritizing improvement opportunities for a complex topic, to an extent not possible were such efforts confined to a rate case proceeding. The concerted efforts and substantial commitment of resources from many groups will prove beneficial to all electric consumers in the state of North Carolina as the following concepts are fully prioritized and implemented.

# 2 Purpose and Rationale for Pricing Modernization

Duke Energy Carolinas' (DEC) and Duke Energy Progress' (DEP) (Collectively referred to as Duke Energy, the Company or Companies) existing pricing strategies and rate designs were thoughtfully developed and approved by the Commission and have been effective for many years. Many rate design features have been able to deliver effective price signals even with historical limitations on granular customer usage data and billing system constraints. Indeed, the analyses conducted as part of the Comprehensive Rate Design Study (CRDS) have validated the quality of historic rate designs. Much has changed in the electric industry over the last 20 to 30 years, however, and current conditions both require and enable modernization of pricing and rate design for the benefit of customers. The Companies' deployment of smart meters and the innovative Customer Connect billing system create opportunities to enhance and improve customer pricing and rate designs in ways that simply were not possible just a few years ago. As ordered by the North Carolina Utilities Commission (NCUC) in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219 for DEC and DEP, respectively, the Companies engaged with stakeholders in the CRDS through a process organized by a third-party facilitator, ICF, to develop an informed vision and direction for the Companies' future pricing and rate design options.

As noted by the originating NCUC order, "as the Company and customers adopt new technologies and uses of the electric system change, rate design must evolve in order to maximize the efficiency and effectiveness of these new technologies and ensure usage of the electric system that is consistent with the public interest." Although the list of topics discussed in the CRDS was comprehensive, the major objectives of the CRDS process were essentially two-fold: First, tariffs, both existing and potential, were evaluated for alignment to system costs and their ability to provide fair and equitable pricing to customers. Second, opportunities to reduce complexity and harmonize the rates offered by DEC and DEP were explored. These two overarching goals can be further expanded as follows:

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**Fair, Equitable, and Modernized Pricing:**

- Provide more customer options as customers increasingly desire more control over energy consumption and costs.
- Account for both the costs and benefits of customer-sited resources and new/expanding technologies such as solar, storage, and electric vehicles (EVs).
- Encourage system-beneficial behavior and discourage the wasteful and/or uneconomic use of energy.
- Modernize pricing to better link to specific system costs and address decreasing homogeneity among customer classes.
- Incorporate affordability elements as developed by a parallel collaborative.

**Simplify and Harmonize Tariffs:**

- Evaluate suite of tariffs offered across DEC and DEP for opportunities to increase commonality of tariffs and/or structures within tariffs.
- Seek ways to simplify tariffs while avoiding undue discrimination.

Several factors both call for and enable meaningful changes to rates and pricing structures in North Carolina today. The electricity value chain has changed dramatically since the existing rate structures were developed. Although those designs have proven robust, they have increasingly come under strain to address both changes to the electric system and customer energy usage behaviors. Thankfully, at the same time, grid technology changes have enabled the necessary modernization of rate design structures. The following factors are driving meaningful changes to rate design structures in the Carolinas.

1. **Electric System Dynamics and Distributed Energy:** North Carolina has one of the highest levels of utility-scale solar penetration as compared to any state in the US. In 2021, DEC and DEP had roughly 4,600 MW of utility scale solar capacity that was expected to grow to more than 7,300 MW by 2026 – a 57% increase[1]. Additional solar resulting from the Carolinas' Carbon Plan could be a further catalyst for expanding solar in the Carolinas. In contrast to the electric system from 30 years ago, Duke Energy has new grid reliability challenges to manage, including the advancing "duck-curve,"[2] and new price signals are needed to encourage customer behaviors to align with new electric system realities. The adoption of EVs over the next decade will have a major effect on the electricity system as one of the largest sources of energy demand converts from gasoline to electric.
2. **Distributed Energy Technologies:** Customers are increasingly adopting distributed energy technologies, such as rooftop solar, advanced energy management systems, and energy storage devices – including an expected increase in dual usage of storage for transportation and backup power. Such adoption is reducing the homogeneity across customer groups, calling for more sophisticated pricing to address issues of fairness and clarity. For example, the number of registered EVs in the United States more than

[1] Numbers from the A2 portfolio from the 2020 modified IRP.
[2] The "duck curve" is an industry term describing the broad system impacts from high solar penetration characterized by relatively low net loads during mid-day hours when solar production is high, followed by a sharp increase in net load in the late afternoon as demand increases and solar production declines.

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tripled from 2016-2020.[3] EV sales have only increased since then, with some models having up to a 12-month backlog in orders.[4] Any increase in gas prices would be expected to only increase interest in EVs from both residential and C&I customers, and the number and variety of available models is expanding to meet the growing demand.

3. **Customer Expectations:** Customers and diverse advocacy and interest groups are requesting new rates and pricing structures to reflect usage differences and help mitigate price pressures. Following virtually every other industry and product, customers and interest groups alike are demanding more choice and control in their energy purchases.
4. **Grid Technology Advancement:** The Company has invested in Advanced Metering Infrastructure (AMI) and a new billing system (Customer Connect), providing the capability for greater customer choice, flexibility and transparency in rates. Full deployment of AMI and Customer Connect provides a platform for more data intensive, yet administratively manageable, rate offerings.

Rate design must collect the revenue requirements of the Companies in a manner that is not unduly discriminatory while also encouraging beneficial consumption patterns to improve system efficiency and keep costs low for all customers. Accordingly, rate design often involves complicated tradeoffs that must consider both system dynamics and wide-ranging differences across customer classes and individual customers, particularly when considering varying levels of energy technology adoption. In other words, customers who operate large facilities around-the-clock and those who use energy sparingly or intermittently should receive pricing designed to reflect those differences. Similarly, solar adopters, EV purchasers, or customers with highly flexible loads should receive price signals that reflect the system economics of the decisions, including consideration of impacts on all other customers.

The following Rate Design Roadmap ("Roadmap") outlines the rate design findings, vision, and direction that resulted from the collaborative stakeholder process that transpired over the past year. Additionally, the Roadmap offers a summary of the CRDS process as designed by the third-party facilitator, ICF, including efforts made to ensure opportunities for feedback from all parties involved.

Foremost, the Companies wish to express, again, their gratitude for the active participation from numerous and diverse organizations and individuals throughout the process. Stakeholders shared their original ideas, feedback, and opinions through the various working group sessions, large forums, and topically focused subgroup discussions. The following represents the Companies' views on future pricing structures and designs, as informed by the collaborative process, but does not necessarily represent full consensus from all parties involved in the Comprehensive Rate Design Study process.

# 3 Roadmap Structure

[3] Electric vehicle market growing more slowly in U.S. than China, Europe | Pew Research Center.
[4] Waiting times for electric cars 2022 | Electrifying.

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The following Roadmap envisions changes across the portfolio of tariffs that will impact virtually all DEC and DEP customers and create opportunities for customers to economically use emerging energy technologies. The ideas and options presented throughout this Roadmap have been discussed at varying levels of detail throughout the large forums, working groups, and stakeholder subgroup meetings over the past 12 months. The collaborative stakeholder process has been detailed extensively with the NCUC in prior quarterly filings.[5] The Companies appreciate all the insights and feedback, questions and discussions, and commitments of time and resources from the diverse stakeholders who reviewed current and potential tariff options and elements. Accordingly, the Companies' plans and priorities listed below are the result of two-way dialogue with stakeholders within the facilitated process. The Companies are hopeful that many of the options identified in the Roadmap will be widely supported and implemented as part of future filings focused on rate design improvements in consideration of the goals listed above.

The Companies recognize the potential for improvements in the following areas, as described in more detail in the remaining sections of this Roadmap:

System-wide Foundational Changes

1. Time-of-Use Period Changes
2. Demand Charge Structure Alignment to TOU Periods
3. Electric Vehicle Options

Rate Design Changes for Residential Customers

4. Expanded Options for Residential Customers
5. Residential Net Energy Metering Reform
6. Subscription Pricing Rates

Rate Design Changes for Non-Residential Customers

7. Improved Price Alignment for Non-Residential Rates
8. Simplification of Non-Residential Rates
9. Expanded Hourly Pricing Options for Non-Residential Customers
10. Non-Residential Net Energy Metering Reform
11. Economic Development
12. Renewable and Clean Tariffs and Programs
13. Historic/Closed Tariffs

Importantly, many of the ideas in the list above cannot be considered in isolation. Rather, the ideas and options are often deeply interconnected and to be effective and cohesive should be implemented in conjunction with

[5] See Comprehensive Rate Design Study Quarterly Status Reports filed on July 21, 2021, October 21, 2021 and January 21, 2022 in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219.

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other options. For example, the options should consider customers with different usage profiles, consumption levels, and degrees of advanced energy technology adoption.

While rate design ultimately must recover the revenue requirement, the ideas stemming from the collaborative process can create benefits, ultimately reducing rates for everyone. When rate designs incorporate the proper balance between reflecting system costs and considering operational capabilities of new or existing loads, the result will be lower overall system costs than would have otherwise occurred (and accordingly, lower rates) as well as an important additional cost-effective tool that will support achievement of the planned energy transition in North Carolina.

# 4 System-wide Foundational Changes

Concepts discussed in this section are both wide-ranging and foundational. The following changes will impact customers of all classes, Residential and Non-Residential alike, across both DEC and DEP. Importantly, the pricing improvement opportunities discussed in subsequent sections assume implementation of foundational alignments for both time-of-use periods and demand charge structures. Rate design simplification and modernization ideas discussed elsewhere for specific tariffs or customer classes is predicated upon alignment of all tariffs to the new system realities, including both demand and energy charges.

## 4.1 Time-of-Use Period Changes

Time-of-Use energy rates include a wide variety of pricing and design options, but generally all 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 other supply resources but also 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 customers who can respond to price signals, can do so in an informed manner. Time-of-use pricing with properly defined periods is increasingly necessary for such proper signaling.

Time-of-Use (TOU) periods currently in place for DEC and DEP were established as early as the 1980s. Although the TOU periods have been reviewed more recently, the latest reviews noted that new TOU periods should be considered after the deployment of smart meters, which would allow a more seamless transition to new rate designs. Given the deployment of Advanced Metering Infrastructure (“AMI”) in the Carolinas, metering capabilities are no longer a barrier to changing TOU periods. Furthermore, the desire for this review of 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 energy storage and EVs.

The Companies took a forward-looking approach in designing the new TOU periods discussed below, 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) accurately reflect the benefits of distributed energy technologies such as electric vehicle charging, energy storage, rooftop solar, and other distributed energy technologies; and 3) make it easier for customers to modify energy consumption patterns and create bill savings.

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The Companies analyzed projected load patterns and costs to develop refreshed TOU periods. Historic and forecasted costs were analyzed through six different lenses: gross load, net load after utility-scale solar, retail load, marginal energy cost, marginal capacity cost, and loss of load expectation (LOLE). Gross load, net load, retail load, and marginal energy cost were examined using the Companies' Cost Duration Model (CDM). The CDM is a model for evaluating TOU prices and TOU periods. The CDM displays weighted data in a single chart for ease of analysis. A detailed explanation of this process was shared in Working Group #1 ("Fast Track") and was also included in the Technical Report filed September 30, 2021 in Docket No. E-2, Sub 1280 in a filing that introduced two new rate designs utilizing the new TOU periods. Figures showing historic marginal cost (Figure 1) and LOLE (Figure 5) are also included as a point of comparison and validation of the CDM. The following Figures 2 through 4 display how the CDM showed expected high and low-cost time periods in 2021, 2026, and 2030.

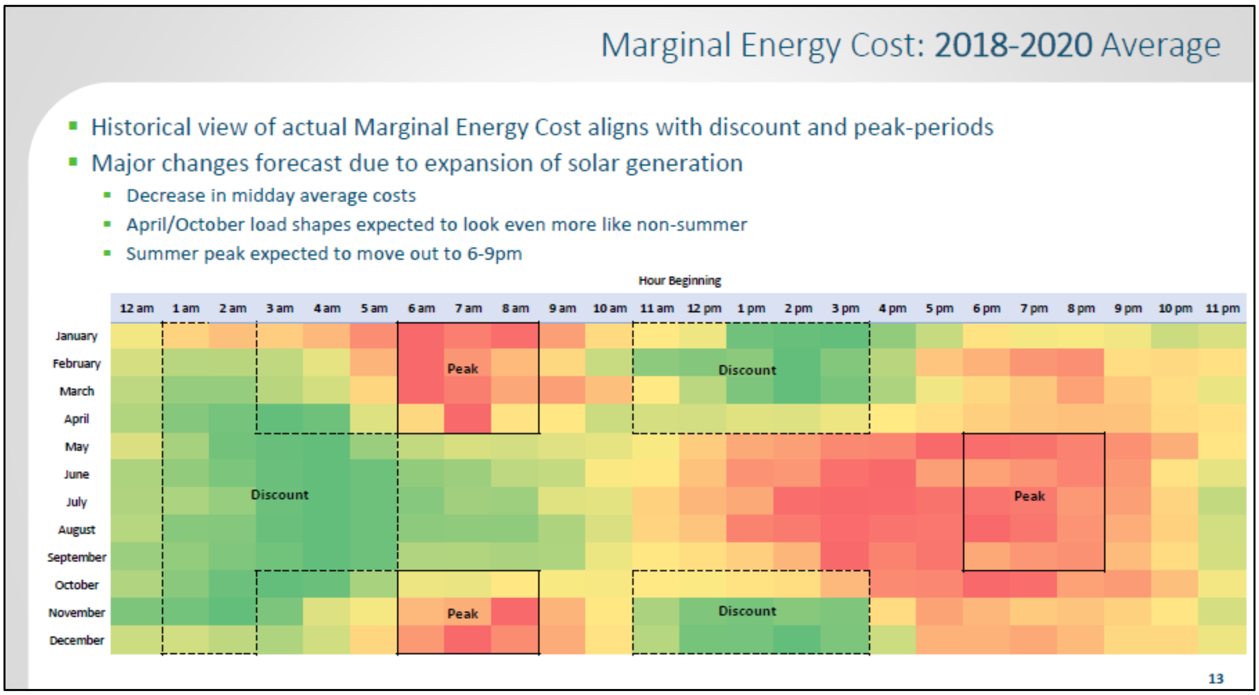


Figure 1: TOU Period Alignment with Recent Marginal Energy Costs

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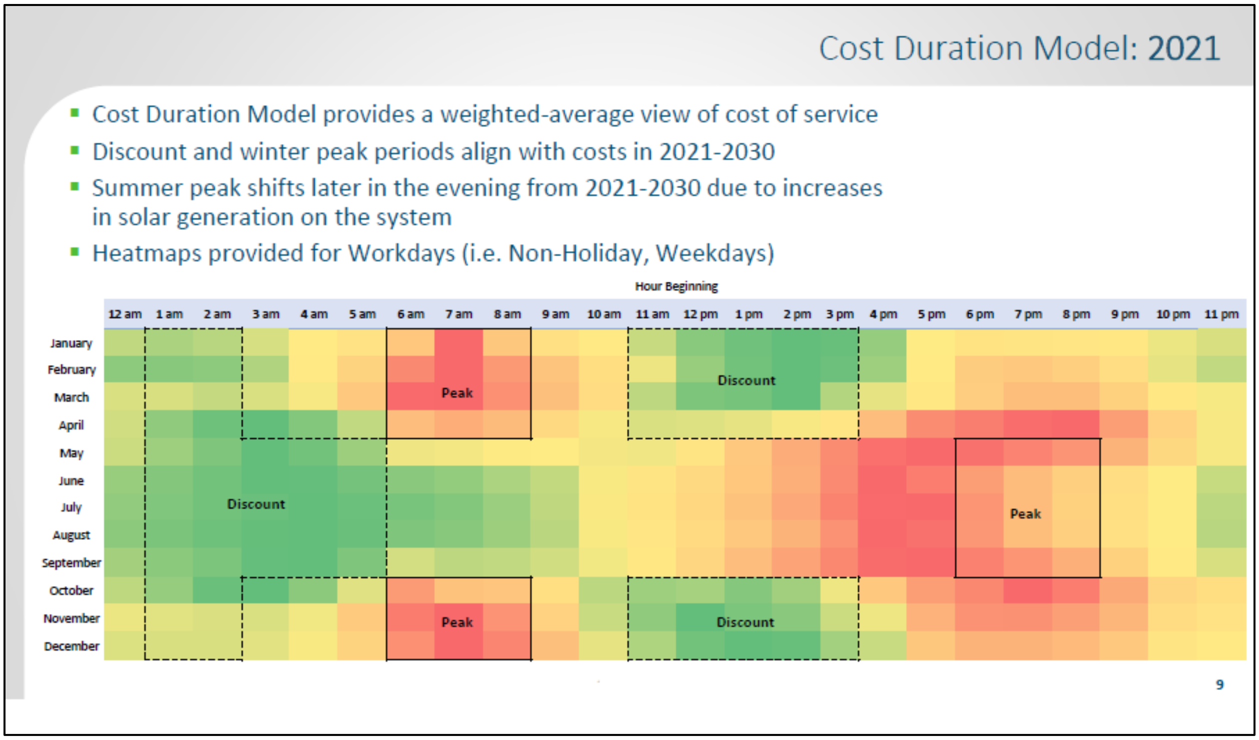


Figure 2: TOU Period Alignment with the Cost Duration Model Output for 2021

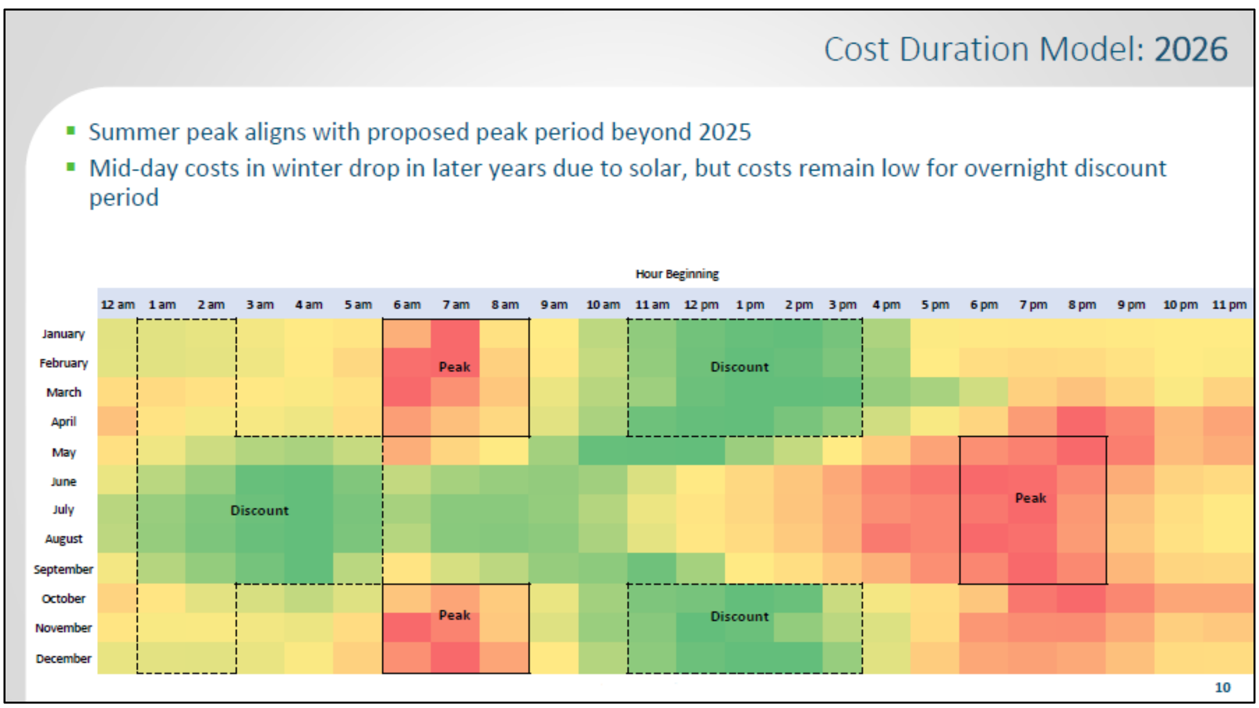


Figure 3: TOU Period Alignment with the Cost Duration Model Output for 2026

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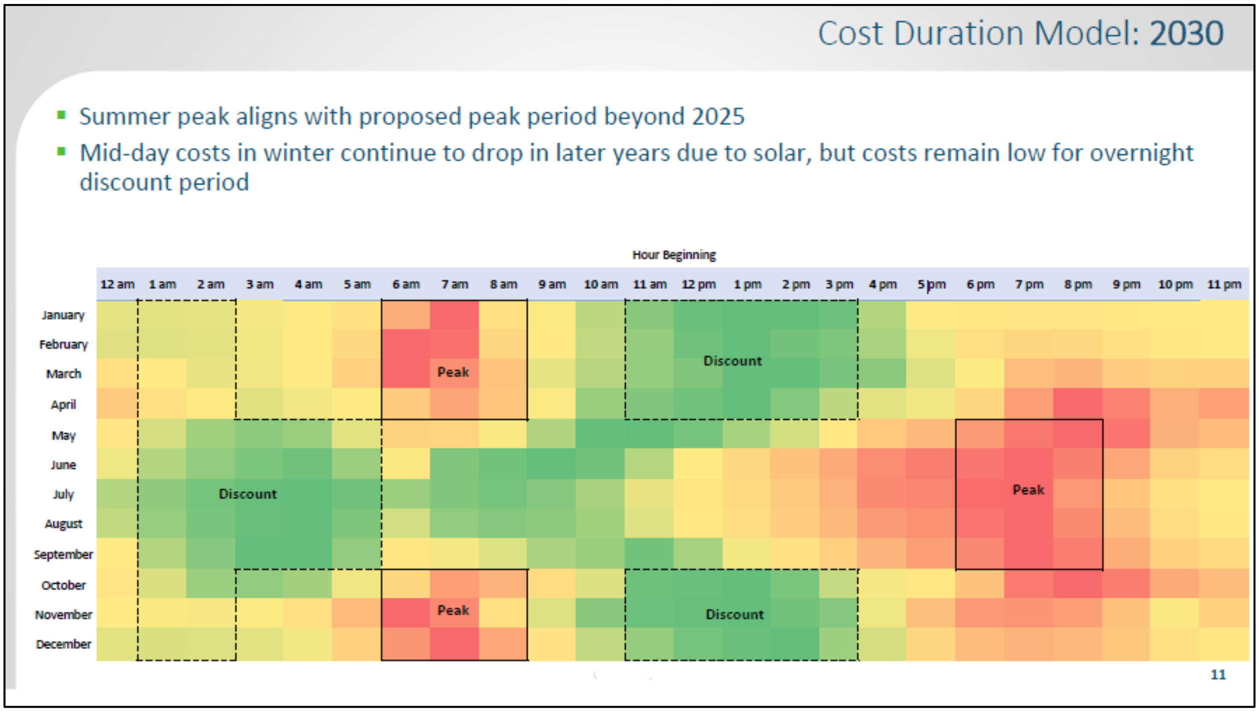


Figure 4: TOU Period Alignment with the Cost Duration Model Output for 2030

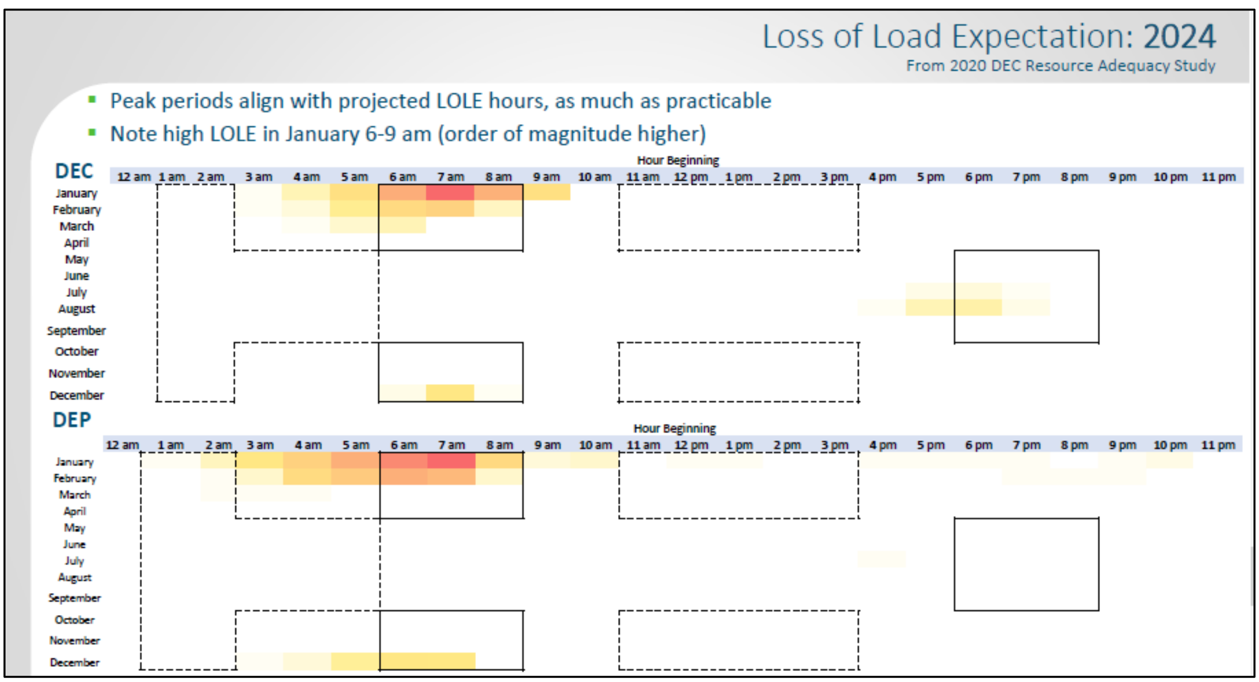


Figure 5: TOU Period Alignment with 2024 Loss of Load Expectation Times

The heat maps above show that the CDM is in alignment with historical marginal energy costs. Since 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 impacts of additional solar energy

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added between 2021 and 2030 are 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 become even lower cost, as these times of high solar generation and relatively low load lead to “duck-curve” situations where solar curtailment could become necessary. 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.

These proposed TOU rate designs will not only offer customers new options to reduce their bills and create system benefits, but also reflect Duke Energy’s commitment to providing customers with innovative rate design choices and program offerings to accommodate differences in how customers consume energy. The Companies expect these designs to be a constructive step forward and to comprise one part of a suite of new rate designs, programs, and customer options resulting, in part, from the collaborative CRDS stakeholder process.

The Companies believe the new TOU periods described below will support accomplishment of the rate design goals listed above. Additional supporting materials and descriptions of how the TOU periods were derived in light of system costs and reliability can be found in the DEP Application for Approval of Two Dynamic Rate Pilots.[6]

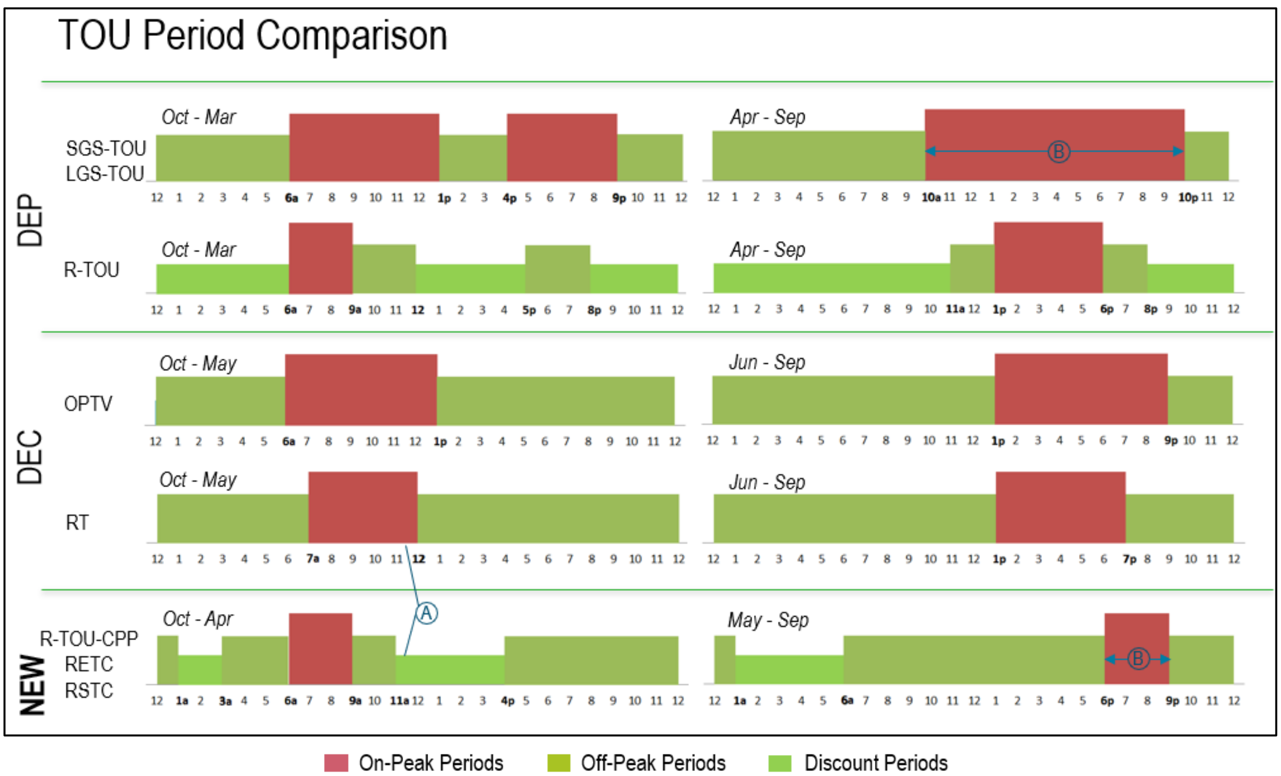


Figure 6: Historic and Modernized TOU Periods

As seen in the “DEP” and “DEC” sections at the top of Figure 6, the Companies’ historic TOU periods vary significantly and do not reflect current system costs and operational realities. Notably, periods present in some of the Companies’ more popular rates (e.g. DEC’s OPT-V) have on-peak periods that are currently low-cost hours for the system, as denoted by letter A in the Figure. Practically, continuation of the existing periods means the

[6] See Application filed in Docket No. E-2, Sub 1280 on September 30, 2021.

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customers would be receiving high price signals that discourage consumption when the system in fact has an abundance of solar energy. Failure to change TOU periods could thus increase 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 current 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. Letter B shows that some present on-peak periods are as long as 12 hours, compared to the 3-hour window for the modernized TOU periods that reflect the system dynamics in the Carolinas today. This new, shorter window creates more opportunities for customers to change their usage patterns or utilize distributed energy storage to reduce their electricity bill.

The modernized periods, shown in the bottom "NEW" section of Figure 1, provide a consistent discount period for owners with flexible loads, for example EVs (whether Residential or Fleet), during overnight hours from 1 a.m. to 3 a.m.[7] While other EV solutions are described below, the discount charging periods provide an important foundation available to all customers with such flexible loads.

During the CRDS, the Company described both the rationale and implications of the new TOU periods to stakeholders for both residential and non-residential classes. Consistent TOU periods across all rates with time-differentiated pricing is desirable and system beneficial. Accordingly, the Companies will prioritize aligning all TOU periods to those present in the CPP tariffs recently approved in both DEC and DEP. With that in mind, DEC recently proposed and was authorized by the NCUC to freeze residential Rate RT[8]. In the future, DEC plans to redesign and reopen the tariff to increase rate optionality for customers.

The Companies recognize new TOU periods may impact customers with different load profiles either favorably or unfavorably. Accordingly, careful consideration will be given to ultimate pricing levels and tariff attributes to mitigate adverse outcomes and rate shock for impacted customers. However, such pricing differences will not be arbitrary, but rather commensurate with how different usage profiles drive system costs, both now and going forward. In addition to TOU rates, the Companies recognize the need for a suite of rate options to provide customers with a choice in available rates. Importantly, TOU rates today are optional, and newly designed periods may result in some customers finding non-TOU rate options more favorable.

## 4.2 Demand Charge Structure Alignment to TOU Periods

The modernized TOU periods described above will also require changes to the demand charge structures for all TOU-D rates, both residential and non-residential, including DEC's recently frozen residential Rate RT and DEP's residential R-TOUD rate.[9] Redesigning these rates will require a thoughtful review of the demand charges, such as

[7] The CRDS discussed the likely need to employ more sophisticated programs in the future to avoid many EVs all starting to charge at the same time to take advantage of TOU periods. A sudden, massive increase in load could lead to ramping issues and distribution circuit or even system peaks that occur suddenly. Some solutions to this issue were discussed in the CRDS, including providing slightly different TOU periods for each EV customers (e.g. some would start at 1 am, others at 1:01 am, still others at 1:02 am, etc. All customers would still get 3 hours of discount electricity prices). While this is an important topic, since this issue is not expected to emerge in the next five years, priority was given to more immediate challenges.

[8] See *Order Approving Closing of Rate Schedule RT*, issued March 4, 2022, Docket No. E-7, Sub 1214.

[9] DEP's R-TOUD rate is currently closed to new customers except Net Energy Metering (NEM) customers.

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the design concept below which was discussed with the Non-Residential Working Group and described in Section 6.2.

As part of the CRDS, the Company discussed demand charge modifications that could support the modernized TOU periods discussed above, including the relatively short on-peak window. As the TOU periods transition to a three time-period structure, the 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 (alignment to cost-causation and actionable price signals) are important and must be held in balance when designing the ultimate rate structure.

One suitable solution is a three-part demand structure that reflects cost causation and promotes customer behavior beneficial to the overall system. The three parts are shown in Figure 7 and described below, including the costs each is conceptually designed to recover.

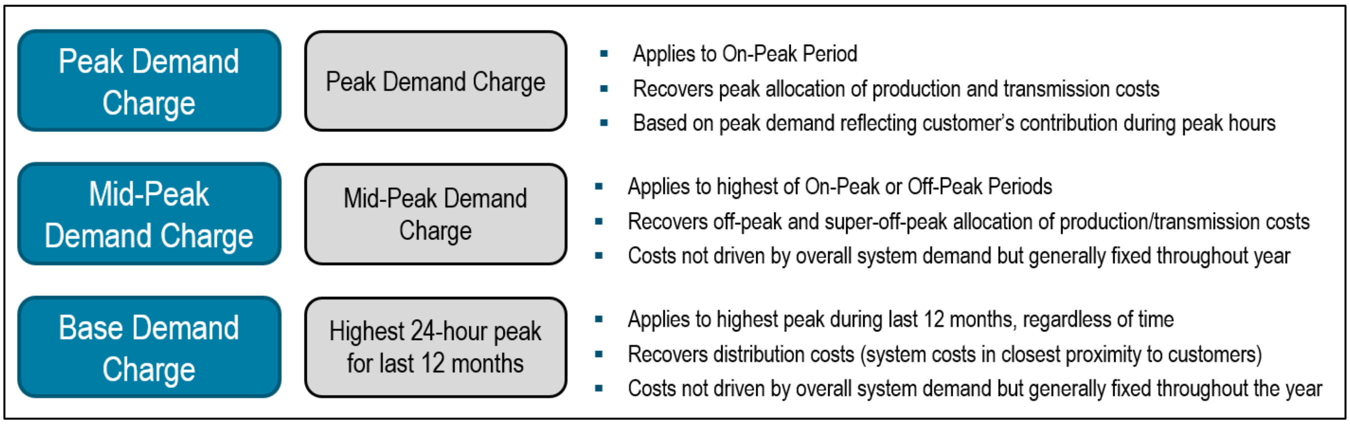


Figure 7: Three-part Demand Structure Overview

**Base Demand Charge:** Recovers 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 customer's highest on-peak, off-peak or super-off-peak demand over the last 12 months.

**Mid-Peak Demand Charge:** Recovers off-peak and super-off-peak 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 peak periods (excludes super-off-peak).

**Peak Demand Charge:** Recovers 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 would improve price transparency and better align with cost causation based on both the size and timing of customer demands. Relative recovery of costs between the three parts of this proposed demand charge structure would be determined through the CDM to maintain cost causation linkage, as well as alignment with the methodologies used to set TOU energy charges. 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

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base demand charge reduces bill volatility for customers, while the Mid-Peak and Peak charges offer opportunities for customers to reduce their peaks and lower their bills.

For example, consider a customer that has some level of demand constantly, but also has some high-demand, infrequent processes. If this customer can avoid having a spike in demand during the 3-hour peak period, they can avoid an increase in associated peak demand charges. This is appropriate because these high-demand processes are not adding to demand or capacity costs during peak periods. However, these high-demand processes are still adding demand during times with moderately high capacity costs and should contribute to intermediate peaking resources. If this customer could run these high-demand processes exclusively during discount time periods, then they are only increasing demand when there is plenty of excess system capacity in the generation or transmission system. Thus, these processes will not increase production or transmission capacity costs making it appropriate for the customer to not pay any incremental peak or mid-peak demand charges for running these processes. However, these high-demand processes could still lead to a local peak at the distribution circuit level rather than in the whole electric system. Therefore, it is appropriate that the increase in demand from these high-demand processes will increase the customer's base demand charge that recovers distribution costs.

The Company shared this hypothetical framework with customers and stakeholders during CRDS discussions in the Non-Residential Working Group, including a simplified revenue-neutral example with prices, as shown in Figure 8 below. Actual structures proposed in future regulatory proceedings could differ and may include attributes to address potential customer impacts from introducing a new rate design. Figure 8 is a helpful representation of the concept and was presented for discussion purposes only.

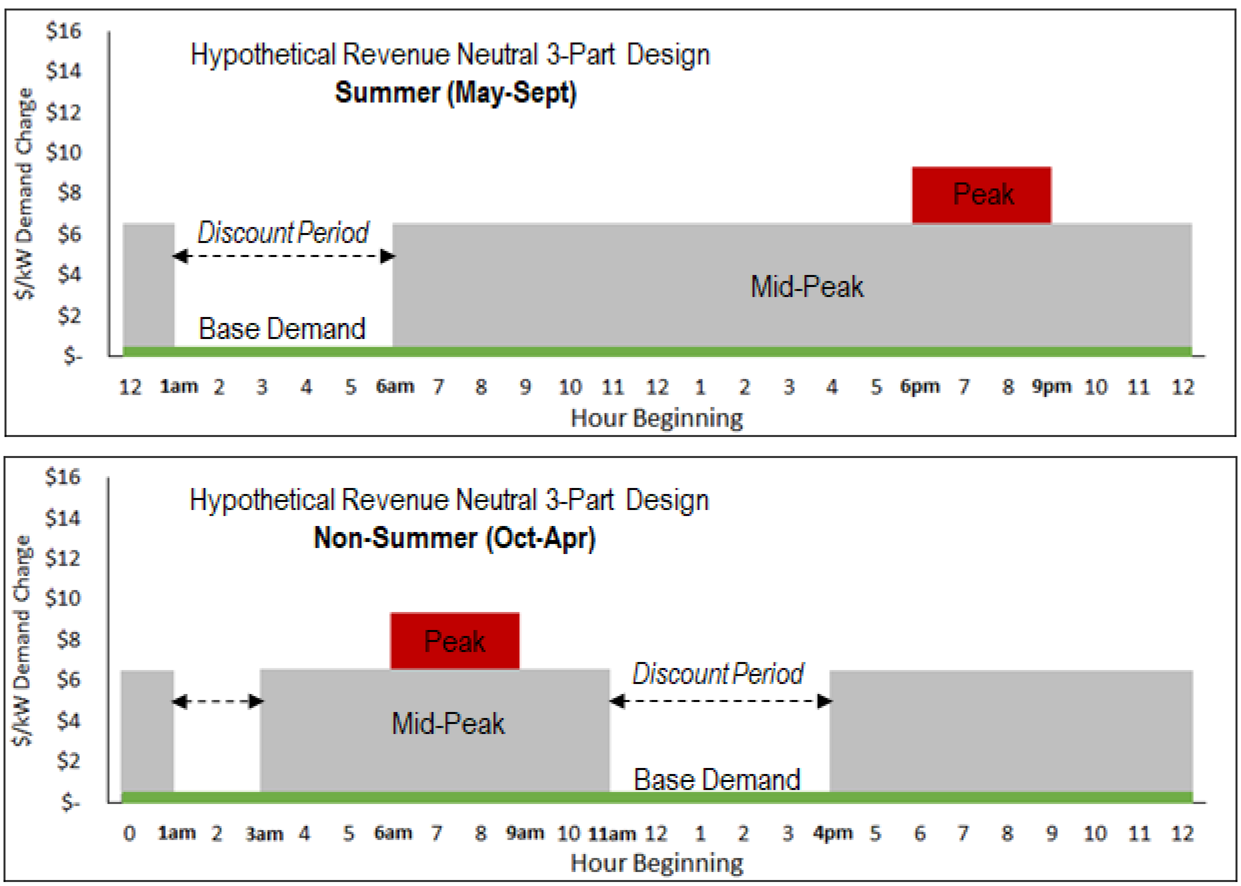

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Figure 8: Three-part Demand Structure Overview

Thoughtfully designed demand charges, along with the new TOU periods, will be foundational to many of the following ideas and potential solutions in this Roadmap. Indeed, sending proper baseline price signals is necessary for constructive and fair expansion of rules governing NEM and other distributed energy technologies (such as storage, microgrids, or other forms of cogeneration) as well as balancing price with cost-causation for customers with beneficial usage patterns (e.g. high load factor customers who make efficient use of system resources). The priorities and opportunities with rate design described elsewhere in this document assume and require redesigned demand charge structures in some fashion to achieve the objectives described.

Customers and customer advocates provided helpful feedback on the new periods during working group sessions, noting the following:

- Impacts to specific customers will depend on the final prices as rate designs are proposed.
- Justified cost shifts could occur between customers who can shift load and those who cannot. *(Note Company comments below.)*
- Allocation of fixed cost recovery to demand charges vs. energy charges should be considered.
- Tiered pricing or other size considerations should be a part of the demand structure design to better align with cost causation.

The Companies will carefully consider and continue exploring these more detailed components of rate design as part of the implementation of new TOU periods and demand structures. Such features would be important to provide rate gradualism and avoid unintentional cost shifts between customers with varying usage patterns, while still supporting the overall goals of improving rate alignment with cost-causation and encouraging system beneficial consumption patterns. The Companies also note that improved alignment between pricing and cost-causation should alleviate some customer concerns, in particular regarding cost shifts. For example, when pricing is aligned appropriately to costs following the CDM approach above, customers who can shift loads away from peak periods would lower overall system costs, thus benefitting themselves and all other customers. In contrast, TOU periods or demand structures that fail to keep up with the changing system cost structure would be more susceptible to adverse cost impacts from load-shifting that provided price signals divorced from system cost realities.

## 4.3 Consistent Price Signal Alignment to System Costs

The Companies analyzed projected load patterns and costs to develop refreshed TOU periods. The Companies used the Cost Duration Model to evaluate TOU periods by examining gross load, net load, retail load, and marginal energy costs. Both historical and forecasted data were used to create robust TOU periods to reflect costs over the next decade and advance the goal of maintaining rate stability over time. It is important to note that the purpose of this analysis is only to set TOU periods. Price ratios and exact prices for any rate schedule will be determined through analyses specific for each utility and jurisdiction. The data sources and lenses were summarized in a presentation shared with the Fast Track Working Group. The full details can be found in the Technical Report filed September 30, 2021 in Docket No. E-2, Sub 1280.

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## 4.4 Electric Vehicle Options

The NCUC explicitly referenced EV rate considerations in its order establishing the CRDS,[10] and several stakeholder participants were focused almost exclusively on improving offerings for this growing customer segment. Furthermore, the NC Governor's recent Executive Order No. 246 set an ambitious goal to increase the total number of registered zero-emissions vehicles in North Carolina to at least 1,250,000 by 2030. The Companies acknowledge the importance of the anticipated growth in EVs and accordingly devoted considerable time to explore options that address EV charging costs and system impacts.

With material and constructive feedback from CRDS participants, the following categories represent ideas that could support the burgeoning EV market in North Carolina. The suite of potential rate designs is intended to provide both favorable pricing and encouragement for system-beneficial charging behaviors, as described. Importantly, beneficial growth of EV load is premised on implementing new TOU periods as discussed elsewhere in this document. Ideas encompass both residential and non-residential EV applications, and some may be considered as pilots prior to broader implementation as this market grows.

Stakeholders generally showed support for EV-only TOU options to encourage Off-peak charging

**TOU Charging:** The easiest approach to regulating timing for EV charging may be providing simple, low-risk incentives to EV owners to charge during off-peak times. One simple approach is EV-only TOU charging, which allows a residential customer to participate in a TOU structure for their EV load alone, leaving the rest of the residence on a non-TOU tariff. Considering the utilization rate of cars is generally low (i.e. they spend much more time parked than driving), it is expected that customers should be able to shift charging across time periods with limited to no effect on convenience. As a result, shifting to a TOU rate design, especially one with shorter 3-hour peak periods, should yield cost-justified savings and a positive customer experience. However, many customers could be reluctant to adopt TOU rate schedules for their entire home due to concerns that regular behaviors for other sources of load may increase bills. This concern is mitigated by allowing customers to be on a TOU design for their EVs while retaining a non-TOU design for the rest of their energy use. EV-only TOU charging received considerable support from stakeholders during the CRDS, with virtually no opposition voiced throughout the process.

**Off-Peak Charging Credits:** Off-peak charging credits provide an upside-only approach where customers can receive a bill credit for months in which there are no instances of on-peak charging, with some allowances. The program could provide a monthly bill savings for average EV drivers, present few challenges in terms of risk or effort, and benefit the system by creating a positive economic incentive for charging during off-peak periods. (Note: Both EV-only TOU and Off-peak charging programs require some technical capabilities to estimate or measure EV usage without a dedicated second meter. Such capabilities are being investigated by the Companies.)

**Subscription Pricing:** EV owners who are concerned about the impact of charging on their monthly bill can benefit from a flat rate subscription program. Many potential EV adopters may not have confidence in how charging their EV will increase electric bills, and a subscription pricing program can provide certainty and eliminate a potential barrier to adoption. Most stakeholders in the CRDS were supportive of managed charging, in which

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[10] See *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* issued March 31, 2021 in Docket No. E-7, Sub 1214 and *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* issued April 16, 2021 in Docket No. E-2, Sub 1219.

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charging would be actively managed by the utility to ensure EV load is brought online in a way that has the lowest costs and environmental impact. Some stakeholders voiced concerns that any fixed price would encourage wasteful usage, and the proposed pilot will study and attempt to address this concern through the following program design considerations. First, the utility would have the ability to call managed charging events that would slow the speed of charging or completely stop charging for a limited period in accordance with program design. Additionally, total allowable energy usage under the subscription program would need to be limited to reasonable levels based on available data concerning EV usage patterns. Based on stakeholder feedback, the Companies filed for pilot Subscription Pricing programs in both DEC and DEP in February 2022.[11] Findings from the pilot could lead to expanded program offerings and a refining of program designs to improve customer experience and enhance grid benefits.

**Economic Development:** Fleet EV owners are typically concerned about demand charges for new/growing fleets that may have low energy consumption and therefore low load factors. One approach is to consider fleet EV adopters in a redesigned Economic Development tariff, to alleviate concerns with demand charges for new or growing EV fleet adopters. In particular, the Company's Economic Development tariffs could be modified to lower availability thresholds and exemptions for the employment requirements for EV fleets. Along with other possible changes to the Economic Development tariffs (see below), such changes would encourage fleet owners to confidently grow into larger fleet sizes with favorable pricing over several years, providing environmental and system utilization benefits. (Notably, such benefits would be compounded when coupled with the new TOU periods and appropriate charging behaviors.)

**Hourly Pricing:** Also, as described in Section 6.3, one stakeholder working group devoted considerable time to evaluating improvements to the Companies' Hourly Pricing tariffs, specifically considering options to introduce a new program with greater availability, including for larger and sophisticated EV fleet owners. The potential design is described in more detail in Section 6.3, but thoughtful consideration was given to the appropriateness of the design for EV fleet customers, particularly fleets expected to growth over 7-10 years or more. In addition, as the Company gains more experience with EV fleets, it may become apparent that the unique characteristics of these customers warrant special application of Hourly Pricing policies to ensure such rate designs work as intended. This may create additional cost-based benefits for these customers.

**Fleet EV Options:** Throughout the CRDS, stakeholders emphasized that EV fleets may have unique needs and capabilities to utilize various rate structures. A few of the ideas presented for consideration include establishing EV fleets as a separate rate class, allowing EV-only TOU for non-residential customers and a non-residential CPP offering. When considered in addition to the potential modifications to Economic Development, Hourly Pricing and TOU pricing, these additional ideas may have limited incremental value for customers.

The suite of possible EV options is presented in summary form below, in Figure 9.

[11] See Application for Approval of Electric Vehicle Managed Charging Pilot, filed February 11, 2022 in Docket Nos. E-7, Sub 1266 and E-2, Sub 1291.

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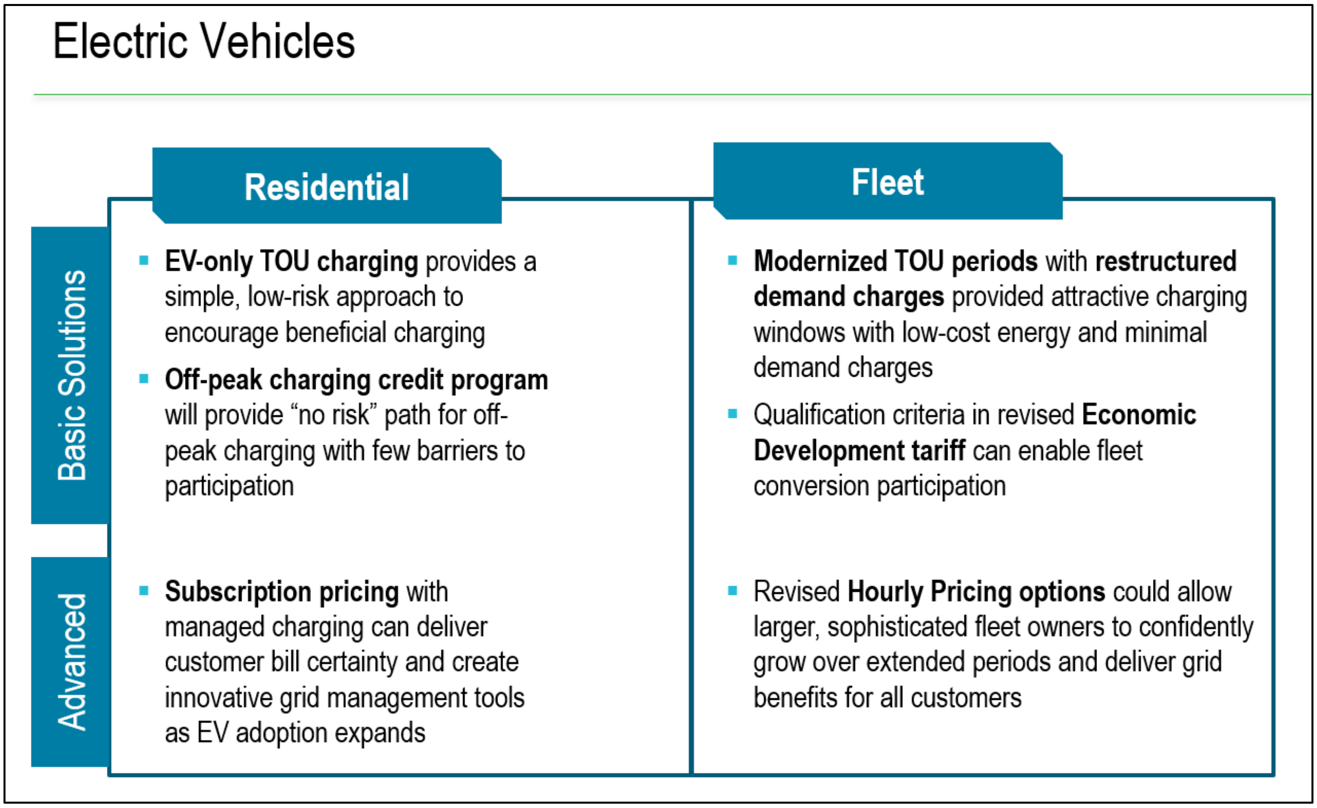
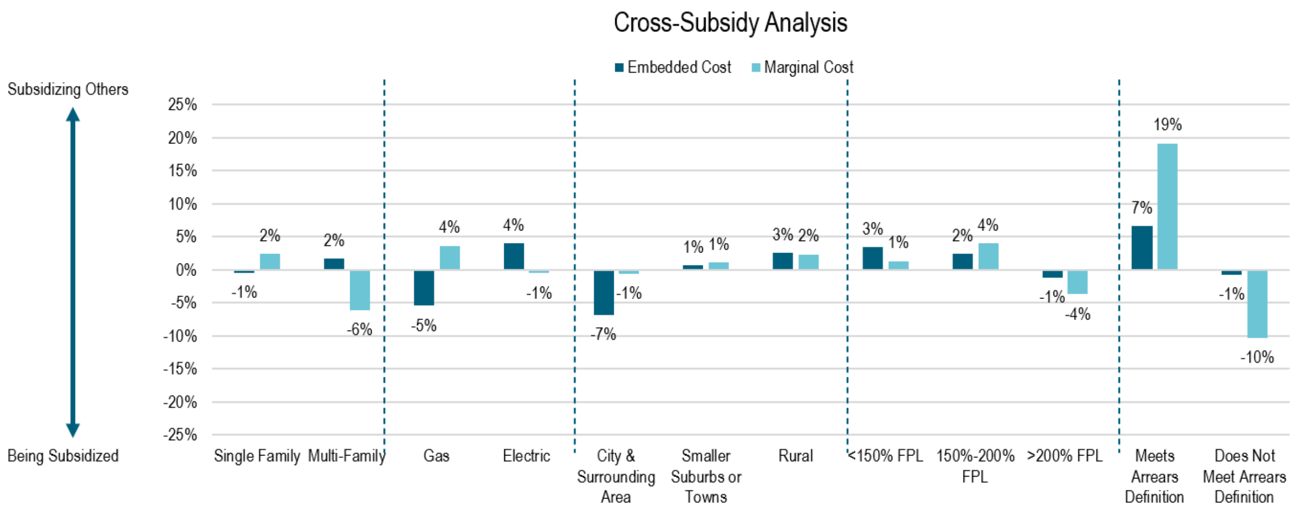



Figure 9: EV Program Options for Residential and Fleet Customers

# 5 Rate Design Vision for Residential Customers

## 5.1 Customer Class Consideration for Residential Customers

Currently, DEC has three residential rate classes – RS (standard service), RE (all-electric service) and RT (Time-of-Use). DEP has one residential rate class. Consideration was given to possible introduction of an all-electric rate schedule or rate class in DEP to provide different rates for this segment of customers. A cross-subsidy analysis of DEP residential customers was conducted across several different categories, some of which are shown below. Please note that both analyses only measure intra-rate class subsidization and have no bearing on potential subsidizations across rate classes (i.e. no conclusions can be drawn from this analysis about subsidizations between residential and non-residential rate classes).




| % Total Customers in Category | 100% | 72% | 8% | 37% | 46% | 18% | 42% | 23% | 66% | 17% | 15% | 85% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|

Figure 10: Cross-Subsidy Analysis for DEP Residential Rate RES (as Presented to Residential WG)

This analysis did not show conclusive evidence of benefits in the creation of an all-electric rate schedule or rate class in DEP. While it appears that electric-heat customers are subsidizing customers with gas heating from an embedded perspective, the reverse is true under a marginal lens. Since both embedded and marginal analyses are important in ratemaking, the overall result is ambiguous. Furthermore, the embedded cost analysis necessarily only utilized the allocation methodologies approved in the most recent rate cases. Any change in the cost of service allocation methodology would impact such intra-class subsidization analyses. Therefore, even though the analysis showed 4% higher bills for electric than the cost to serve those customers under the embedded perspective, on balance a separate all-electric rate schedule does not appear warranted.

The DEP cross-subsidization analysis included other interesting findings such as that customers who are behind in paying their bill (the "meets arrears definition") appear to be cross-subsidizing those that do not meet that definition.[12] Rural customers also appear to be mildly subsidizing urban customers. This is due to an overall subsidization of low-usage customers by high-usage customers and cost recovery primarily through kWh charges. Additionally, the costs included in the cross-subsidy analysis used the Commission-approved processes and methodologies. Those methodologies do not consider potential differences in serving different residential customers. For example, rural residential customers could have a higher distribution cost than customers living in a downtown apartment building. However, the Commission-approved methodologies treat all residential customers as the same in the cost of service study and such distribution cost differences were not included.

The working group discussed how the low fixed charge compared to the customer unit cost and higher load factors relative to the summer peak for high-usage customers were contributing factors to the high-usage/low-usage subsidization. However, the working group showed little interest in adapting rate schedules or rate classes to address this, especially given public policy goals of encouraging energy efficiency and energy conservation.

[12] The definition is either being late 1x one's average bill for 6 out of the 12 months analyzed (50% of the time) or 2x one's average bill for 2 out of the 12 months analyzed (16.7% of the time).



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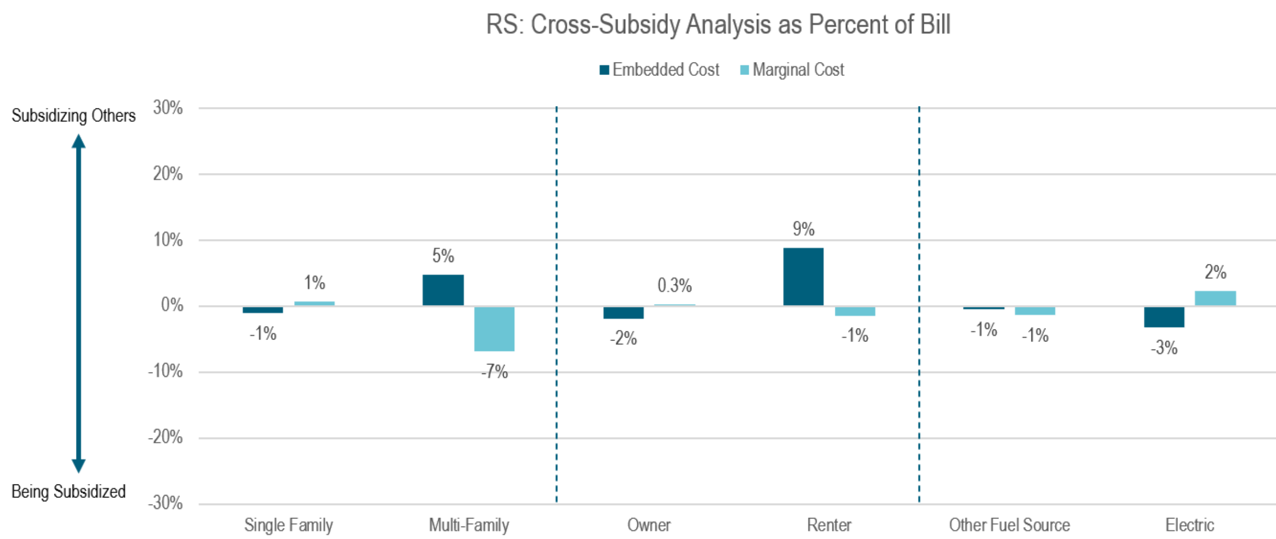
Although this analysis is informative and will be used to inform future rate designs, there was little interest in dividing the DEP residential rate class into multiple groups.

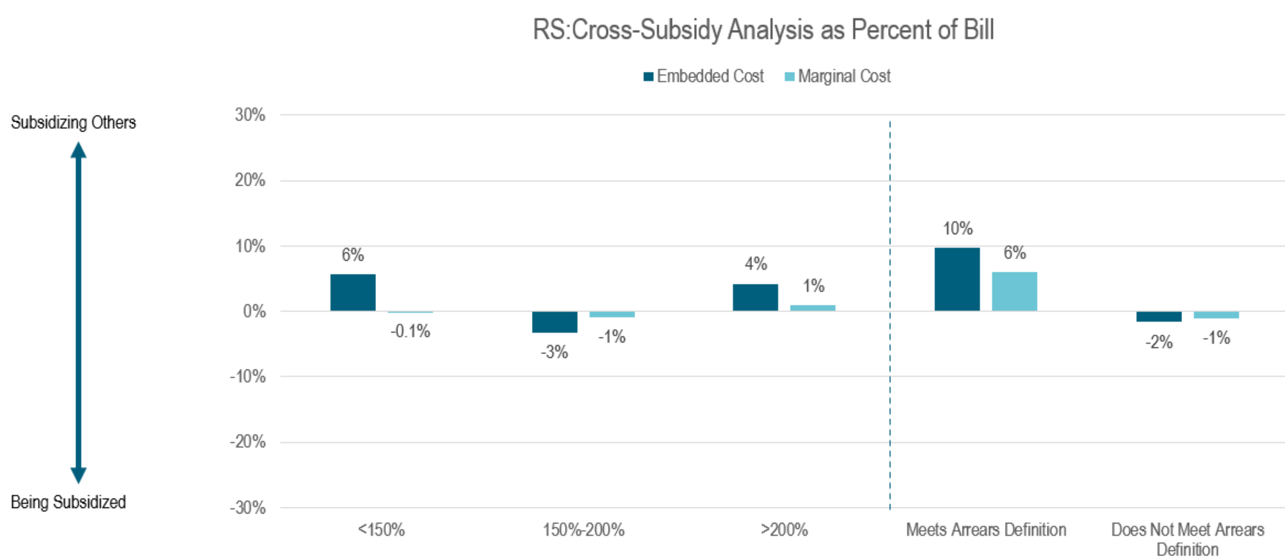
A cross-subsidization analysis was also conducted for DEC, as shown in Figures 11 through 14 below.




| % Total Customers in Category* | 82% | 7% | 78% | 13% | 89% | 0.4% |
|---|---|---|---|---|---|---|

*Not all customers can be categorized, resulting in percentages not necessarily summing to 100%

Figure 11: Cross-Subsidy Analysis for DEC Residential Rate RS (as Presented to Residential WG)




| % Total Customers in Category* | 12% | 9% | 68% | 14% | 86% |
|---|---|---|---|---|---|

*Not all customers can be categorized, resulting in percentages not necessarily summing to 100%

Figure 12: Cross-Subsidy Analysis for DEC Residential Rate RS (as Presented to Residential WG)

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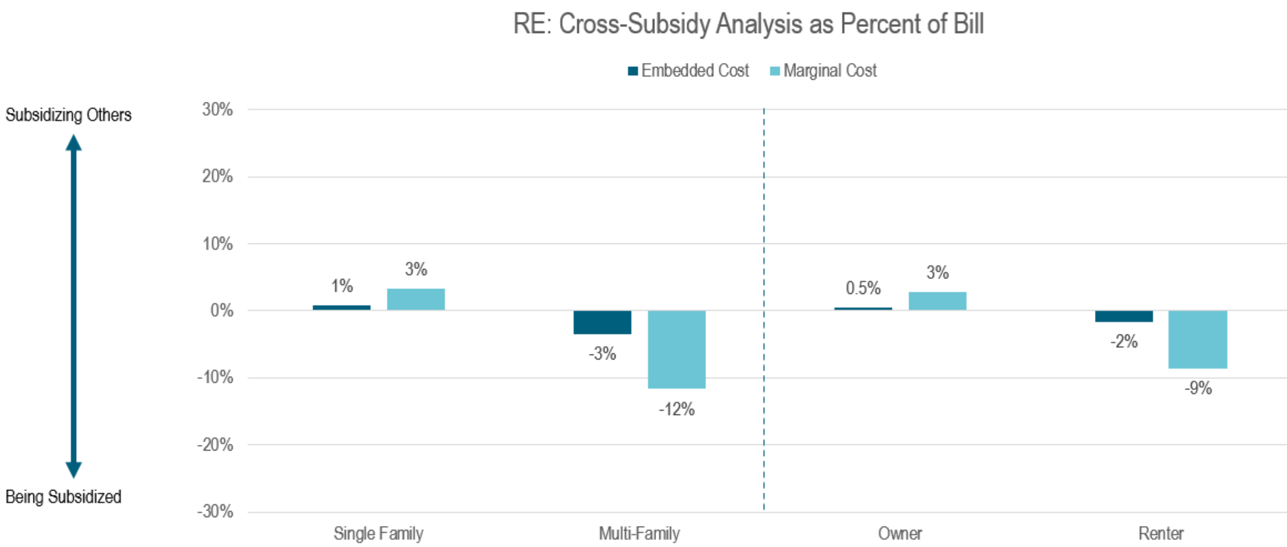
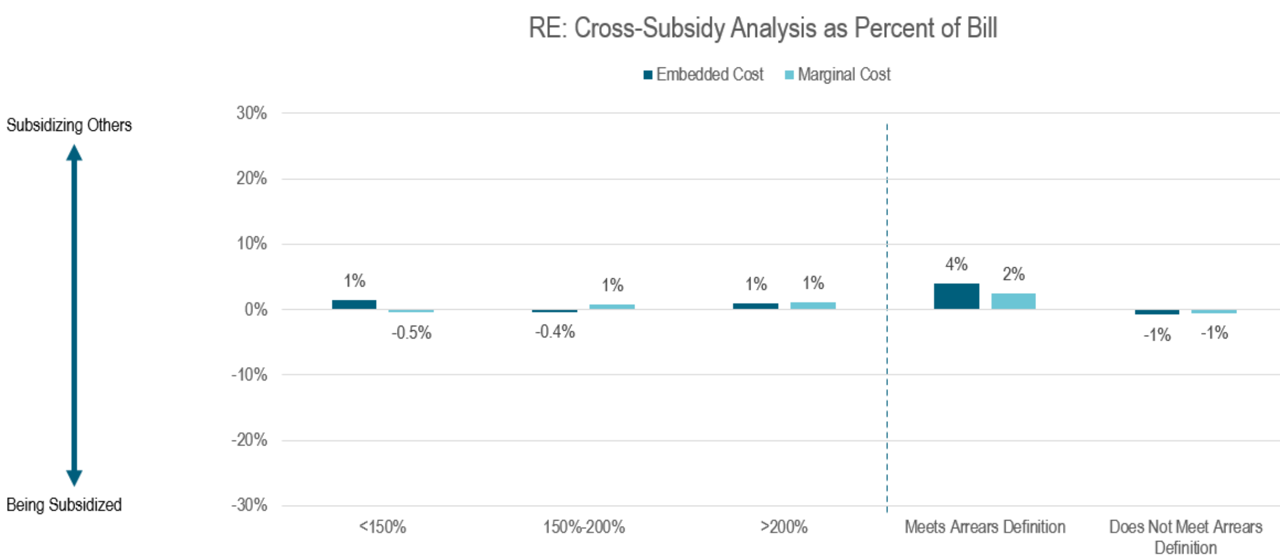



| % Total Customers in Category* | Single Family | Multi-Family | Owner | Renter |
|---|---|---|---|---|
| | 66% | 21% | 67% | 22% |

*Not all customers can be categorized, resulting in percentages not necessarily summing to 100%

Figure 13: Cross-Subsidy Analysis for DEC Residential Rate RE (as Presented to Residential WG)




| % Total Customers in Category* | <150% | 150%-200% | >200% | Meets Arrears Definition | Does Not Meet Arrears Definition |
|---|---|---|---|---|---|
| | 13% | 9% | 64% | 17% | 83% |

*Not all customers can be categorized, resulting in percentages not necessarily summing to 100%

Figure 14: Cross-Subsidy Analysis for DEC Residential Rate RE (as Presented to Residential WG)

As this analysis is focused on intra-class cross-subsidizations and DEC has different rate classes for RS and RE, this analysis does not directly address if the split rate classes are appropriate. DEC has also moved to be winter planning and therefore electric heat customers invariably contribute more to winter peaks than if they had gas heat. If the allocation methodology for production and transmission costs changes, it is possible that customers

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that are part of the RE rate class would face rates that are equal or even greater than the rates under RS. If this occurs, DEC may want to consider creating one residential rate class, creating alignment with DEP.

## 5.2 Expanded Options for Residential Customers

At present, the Companies essentially have four types of core residential tariffs between DEC and DEP. While adoption rates for the various TOU options remain low at present, customer appeal may increase with more customer-friendly TOU periods alongside customer adoption of distributed energy technologies. These four rate structure types were considered as part of the CRDS and are outlined below, including a summary in Figure 5. At a high level, the Company favors as much consistency and commonality between DEC and DEP across the suite of Residential rate offerings as practicable.

1. **Rate RES/RS/RE (Non-TOU Rates)** – DEP's standard volumetric rate and the tariff chosen presently by ~98% of residential customers. The rate consists of a fixed customer charge and volumetric energy charges, with some pricing features to address seasonality and expected higher load factors from customers with electric heating. For example, DEP-RES currently prices winter energy consumption lower, while DEC-RE is reserved for all-electric customers and provides a lower price for higher consumption levels during winter months. The appropriateness of such features was discussed in the CRDS given DEC and DEP's winter planning status. The Company will continue to review cost of service differences for these customers and design tariff attributes to fairly represent usage behaviors. Also, the Company's new data capabilities and billing system will help interested customers understand their potential to save by switching to TOU rates, which can provide actionable alternatives to customers, who today have limited tools to evaluate the merits of TOU options.
2. **Rate R-TOU (Time-of-Use Rate)** – DEP's TOU rate serves only a fraction of customers at present. As described above, the TOU periods for this rate need to be modernized to provide actionable price signals and more opportunities for customers to save. Some customers interested in TOU options may be wary of Critical Peak Pricing (CPP) or demand charges and may find a static TOU rate attractive, but in most cases the TOU-CPP rate and TOU-Demand options provide customer choice with a manageable number of options.
3. **Rates R-TOUD/RT (Time-of-Use Demand Rates)** – The Companies each have residential tariffs that include TOU and demand features. DEP's TOU-D rate is currently closed to new customers except those taking service on the net metering Rider, and DEC's RT rate will be closed to new customers as of April 1st, 2022. The Companies plan to modernize and reopen these tariffs to residential customers in the next rate case for each utility. While demand rates are more complex and likely only desired by a fraction of customers, expanding customer choice to include a relevant and appropriately priced demand rate is desirable. Importantly, the demand structure for this rate option will need to be modified using similar considerations described for the non-residential demand charge structure changes outlined elsewhere, although with less complexity. Customers with peak shaving capabilities (e.g. battery storage) would be the most likely candidates to benefit from a rate schedule with a demand charge. Conversely, customers with an EV or

Stakeholders noted concern for residential demand rate complexity but also a desire for options

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rooftop solar may not benefit from a demand charge. A modernized demand charge structure is necessary to ensure appropriate recovery of fixed distribution costs given the potential capability of a 4-hour battery to avoid peak demand charges, which as described in the non-residential discussion would only avoid the on-peak related transmission and generation embedded costs.

Stakeholders in the CRDS process expressed concern about such demand rates, and the Companies agree that such rates are more complex and generally not the most appropriate structure for residential customers. However, maintaining a well-designed rate with a demand feature could meet the needs of a possibly growing subset of residential customers.

4. **Rate R-TOU-CPP/RSTC/RETC (Critical Peak Pricing Rates)** – The Companies have both filed and received approval for new TOU-CPP rates over the past 2 years. DEC's new rates stemmed from information gleaned from a suite of CPP options tested in pilot form. DEP's new rate similarly benefitted from the pilots as well as the CRDS process. These rates were described in detail in their respective dockets and include the modernized TOU periods the Company believes are appropriate to reflect in all other TOU rates. Namely, the new periods provide customers the ability to save through both load-shifting to off-peak and discount periods. The CPP aspect of the rates provides an opportunity for the customer to respond to up to 20 critical-peak events per calendar year, called on a day-ahead basis. Importantly, these rates are foundational to the Companies recent residential NEM reform applications, if approved, because all future residential NEM customers would be required to take service under these base tariffs.

The Companies will also investigate the need for any continuing cost differential in the Fixed Customer Charge between TOU and non-TOU rates, given the potential for such differences to create a barrier, however small, to adoption. At present, DEP's TOU and TOU-D tariffs have fixed customer charges that are higher than the purely volumetric tariff. The Companies are investigating the cost differences with the efficiencies and capabilities from AMI metering to determine if such price differentials are still necessary. Future study may also include the extent to which Fixed Customer Charges for non-TOU rates should be higher than TOU or TOU-D rates given the improved alignment to fixed costs for such pricing structures.

Figure 15 below outlines the current suite of Residential rate offering for both DEC and DEP, including existing features and potential attributes for interested customers.

| | RES / RS / RE | R-TOU | R-TOUD / RT | R-TOU-CPP / RSTC / RETC |
|---|---|---|---|---|
| Direction | Largely Remain the Same (may change seasonal pricing and tiering) | Modify *(TOU Periods)* | Modify *(TOU Periods)* | Remain Same |
| Basic Customer Charge | Existing feature | Existing feature; consider continuing need for differences vs. volumetric rate | | Existing feature |
| Energy Charges | Volumetric with some seasonal and tiering features | Energy pricing will align to new TOU periods and include on-peak, off-peak, and discount pricing for each TOU option | | |

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| | | | | |
|---|---|---|---|---|
| Demand Charges | N/A | N/A | Conform to new TOU periods, accommodate storage | N/A |
| Dynamic Price | N/A | N/A | N/A | Up to 20 Critical Peak events per year |
| Interested Customers | At present, majority of customers | Customers adopting smart t-stats or EVs | Customers adopting storage technology | NEM Customers or those with smart t-stats or EVs |

Figure 15: Suite of Current Residential Tariff Options Across DEC and DEP

For Comparison, Figure 16 below shows a stylized view of the differences in energy rates by time period for the non-demand options described above. (Riders have been excluded for simplicity.) Energy charges for RES-TOU-D would be lower as some costs would be recovered through demand charges. Customers willing to accept higher prices during peak periods and during Critical Peak Periods can enjoy the lowest prices during off-peak and discount periods, which can benefit flexible loads such as EV charging. While the addition of on-peak pricing in the TOU rate allows for considerable differences between on-peak and off-peak/discount pricing, the addition of CPP events only modestly adjusts the off-peak pricing benefits (due to the limited number of CPP events annually).

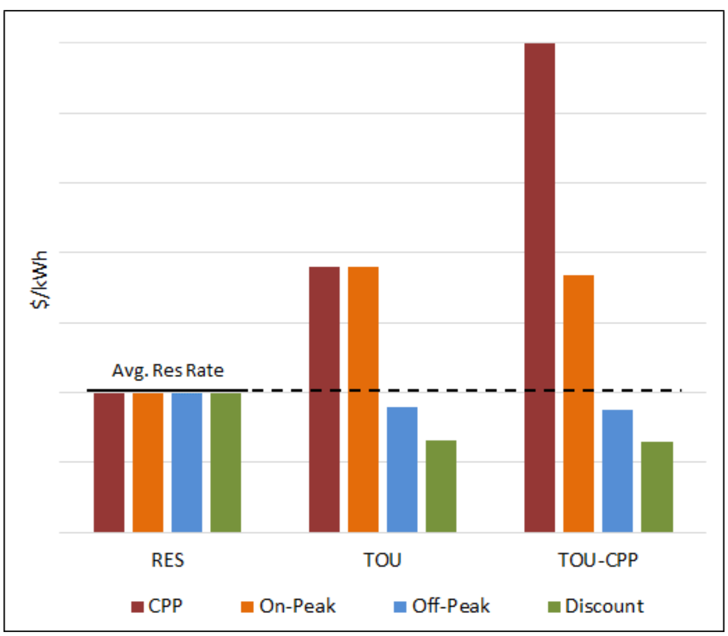


Figure 16: Stylized Pricing Comparison for Potential Suite of Residential Tariffs

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Finally, the Companies' note that Residential participation on TOU rates remains low, certainly in comparison to non-residential customers. There is an interest to get more participation as TOU rates better reflect cost causation even though variable pricing may be intimidating to many customers who have concerns about bill uncertainty. Accordingly, the Companies recognize the potential need to bundle behavioral demand response programs, such as Peak Time Rebates, or other load management tools with rate design options to encourage adoption and enable additional responsiveness. As availability and customer interest in distributed energy technologies increase, the Companies will seek ways to harness the usefulness of these various devices through product offerings that work with well-designed rate structures to provide value to both the customer and the overall system. These devices would potentially include in-home storage, EVs, load control technology, smart thermostats and behind the meter solar systems. The potential for EVs to provide Vehicle to Home (V2H) or Vehicle to Grid (V2G) could also create opportunities. The overlay of subscription concepts to these devices in a bundled offering can lead to managed use in product offerings that provide cost certainty for the customer while seamlessly providing system benefits that flow to all customers.

## 5.3 Residential Net Energy Metering Reform

The Companies recently filed a Residential Net Energy Metering reform application with the NCUC in Docket No. E-100, Sub 180. The filing resulted from discussions within the CRDS and subsequent agreements on reform with a broad group of stakeholders. The Companies' joint application represents an important and early outcome from the CRDS that provides benefits to all customers, as described in the application documents. Additionally, the Companies noted details of the discussions leading to the application in the CRDS quarterly reports.

## 5.4 Subscription Pricing Rates

The Companies recently filed a Residential EV Managed Charging pilot application with the NCUC in Docket No. E-7, Sub 1266 for DEC and Docket No. E-2, Sub 1291 for DEP. The pilot will consist of up to 200 participants (up to 100 participants in DEC and DEP each) and last for 12 months. The price is a flat, subscription rate of $19.99 (DEC) or $24.99 (DEP) for participants to charge their EV at their home, with few limits on the amount that vehicle can charge.[13] In return, the Companies will actively manage charging of the vehicle and schedule up to three managed charging events per month. The Companies discussed with the CRDS how managed charging can be beneficial for EV owners and non-EV owners.

> Managed charging assuaged some stakeholder concerns regarding subscription rate energy usage

The Residential EV Managed Charging Pilot eliminates a barrier for customers with respect to EV adoption and cost uncertainty, but also affords the Companies a powerful grid management tool that would not exist or exist only partially with self-managed charging. This is because subscription rates offer possibilities for improved grid management from customers who may lack either the capabilities or sufficient financial incentive to manage consumption independently. Absent the subscription program, EV owners may default to initiating charging whenever they arrive home, quite possibly yielding poor or detrimental charging patterns for

[13] As filed, a participant will receive a warning for using more than 800 kWh in one month for charging. Any participant that uses more than 800 kWhs for three months, or more than 1,200 kWhs in any month, may be removed from the pilot at the Company's discretion.

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the grid (e.g. 6 pm on a summer afternoon). Even a customer using a timer to charge during only off-peak periods when on a TOU rate falls short of the value creation from utility management – specifically, the ability to space out charging across the window to avoid coincident charging peaks and respond to critical grid events as necessary – including events affecting specific grid locations, which cannot be addressed fully through a TOU price signal alone. Indeed, broader price responsiveness, including on a locational basis, from the residential customer class is likely to factor heavily in the Companies' Carbon Plan for the Carolinas.

Subscription Rates may also be worthy of consideration beyond EVs. Customers have historically shown a strong preference for the bill certainty associated with Fixed Bill products, as demonstrated by high annual renewal rates, and managed components can help ensure grid benefits for consumption beyond just EVs. Utility-managed solutions paired with Subscription Rates also has the potential to reach an entirely new set of customers that otherwise may not choose to go on TOU rates. Customers who might not naturally save money by switching to a TOU rate may not migrate to TOU rates and would thus not have the ability to take advantage of savings through improved consumption management. Subscription Rates, however, enable the utility to design a price specific to an individual customer's profile and leverage management tools to benefit the customer and the grid. Given the significant opportunity to address system needs as shown in the Companies' Winter Peak Study filed in Docket No. E-100, Sub 165, the Companies may consider future subscription options beyond EVs.

Results from a recent survey of customers regarding subscription pricing were shared with the Residential Working Group. The survey found that there was customer interest in such a program, especially among low-income customers who appreciate bill certainty. Stakeholders mentioned concerns regarding how fixed prices could result in higher energy use, which the company promised to carefully consider in any potential future programs or filings.

# 6 Rate Design Vision for Non-Residential Customers

## 6.1 Evaluation of Present Rates' Alignment to Costs

Based on questions and feedback from stakeholders during the CRDS, as well as the initial directives provided by the NCUC, the Companies explored the extent to which present rate designs reflected cost causation, primarily evaluating embedded costs[14] based on the unit costs developed as part of the cost of service in the Companies' most recent rate cases.[15] Importantly, such investigations were enabled by advances made in the Companies'

[14] The Companies also verified that current rates are above marginal cost. Embedded costs are historical and relate to the cost of existing production, transmission, and distribution assets, etc. Marginal costs are forward-looking and include the incremental cost of additional energy or capacity. Both are important measures used to determine proper rate designs.

[15] NCUC Docket No. E-7, Sub 1214 – In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina; and NCUC Docket No. E-2, Sub 1219 - In the Matter of Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina.

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capabilities and approaches to data analytics. The following elements constituted the Companies' advanced analytic approach.

- Population level analysis – Rather than relying upon a sampling approach to understand bill impacts for various customer classes, near-population level data sets were used to eliminate concerns with sampling errors. As customers classes become less homogenous, greater levels of granularity are helpful in understand the full impacts of rate design changes.
- Interval data – The Company used hourly, 15-minute, or 30-minute consumption data to evaluate tariff pricing effectiveness and new TOU period considerations. Billing determinants based on prior TOU periods are inadequate for designing and pricing new TOU periods, including determining the impacts across the range of customer usage profiles.
- Embedded and marginal costs – The Companies leveraged both the unit cost analysis from the prior rate case and marginal cost histories to evaluate the effectiveness of pricing approaches through both important lenses.
- Customer Segmentation Data – The Companies used customer segmentation data where appropriate to evaluation price and cost causation alignment within customer classes, particularly within the residential classes. The Companies also discussed Non-Residential classes within the Non-Residential Working Group and implications to rate design. Ultimately, focus on improving cost-causation alignment with pricing across existing tariffs and rate classes through TOU period changes and demand charge restructuring was prioritized over restructured classes. Making substantial changes to both the tariffs and rate classes at the same time would be more complex, therefore revisiting the classes subsequent to TOU modernization is appropriate.

The most relevant question pertaining to existing rate design is whether pricing reflects the differences in embedded costs across customers with varying load factors within a particular tariff. The Company considered several tariffs in the CRDS, and presents example results here for context.

**DEP – Small General Service Time-of-Use (SGS-TOU) and Medium General Service (MGS)**

SGS-TOU is available for customers with demands between 30kW and 1,000kW. The following analysis considers the present tariff design, which is comprised of a two-tier TOU structure (on and off peak) with on-peak and economy demand charges. Demand charges currently contain a seasonality feature, with lower pricing during non-summer months. Also, as seen in Figure 17 below, SGS-TOU becomes the preferred rate for customers in this demand range once load factors exceed 35-40%. Customers with load factors below 40% are more likely to be on Rate MGS, the non-TOU option for customers with demands ranging from 30kW to 1,000kW. (Load Factor is the ratio of average demand to peak demand, with higher load factor indicating that a customer operates at/near their peak demand more often, consuming more units of energy per unit of demand.)

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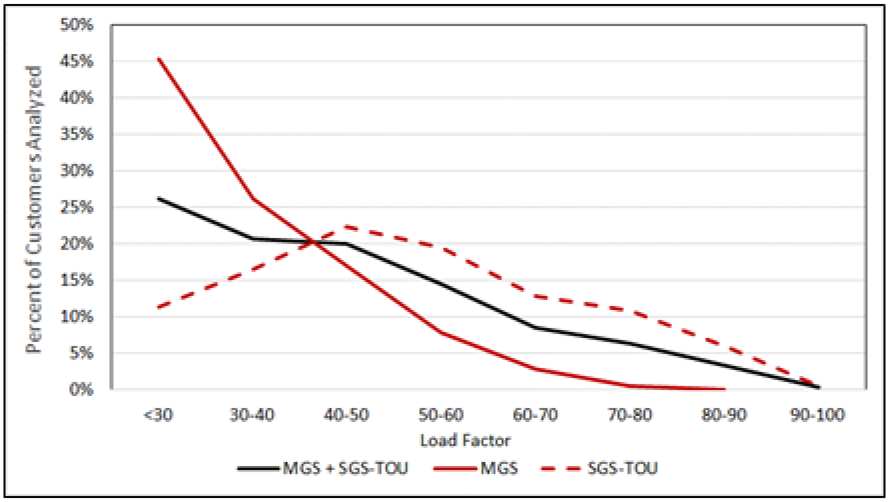


Figure 17: Customer Load Factors on DEP's NC Medium General Service Tariffs

The Company then evaluated the embedded cost contribution for each customer in the load factor ranges shown in Figure 17 using the unit costs developed for DEP's last rate case. In parallel, the Company calculated the bills for a majority of customers on the current tariffs using the same interval data for comparison. As the relationship between embedded cost and pricing is a function of inter-class recovery resulting from the rate cases, the Company normalized the data using the 40-50% load factor range as a baseline (effectively controlling for inter-class differences and allowing isolated focus on differences across the tariff based solely on load factor). The results for the price and embedded cost analysis are in Figures 18 and 19 below.

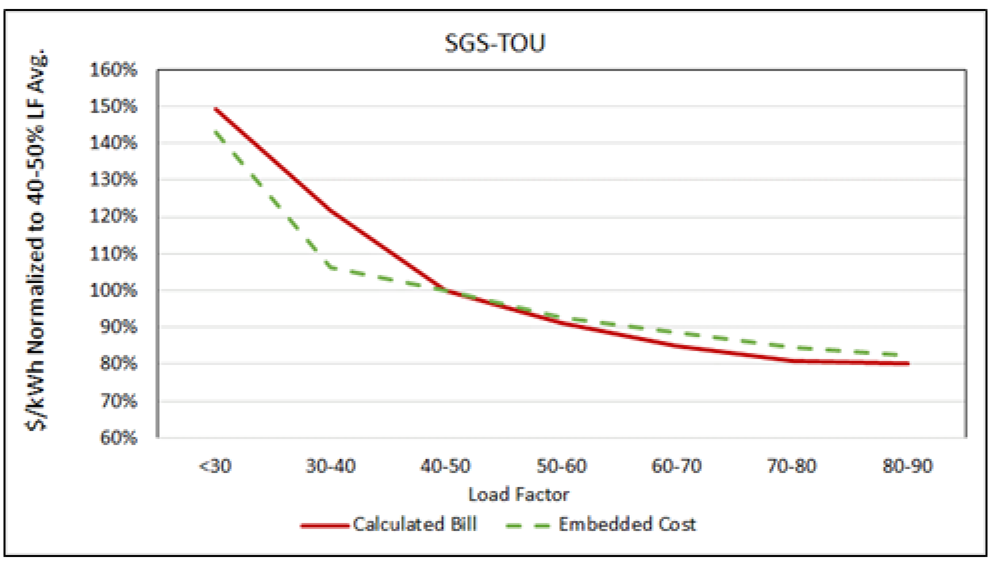


Figure 18: Relationship of Price to Embedded Cost for DEP's Current NC Medium General Service TOU Rate

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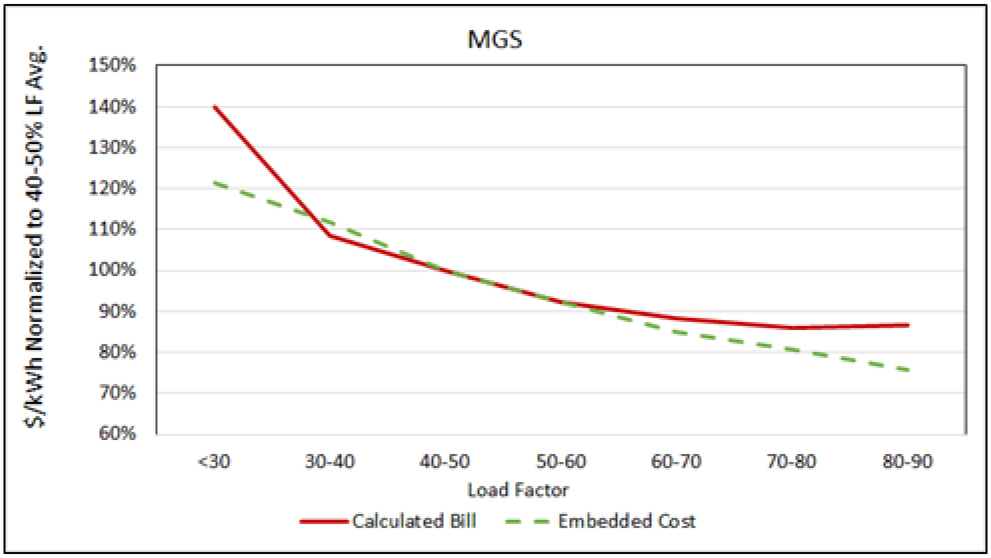


Figure 19: Relationship of Price to Embedded Cost for DEP's Current NC Medium General Service Rate

As seen in the graphs above, SGS-TOU yields a declining cost per unit of energy ($/kWh) with increasing load factor, which is expected and desired given the more efficient use of resources by high load factor customers (the cost of providing capacity for service is covered by more kWh, thus lowering the unit cost per kWh). Notably, for the range of load factors typically taking service under SGS-TOU (i.e. >40% load factor), the price curves matched with the embedded cost curves quite well. Note that embedded cost per unit of energy for customers with 80-90% load factor is around 80% of the per unit of energy cost for customers with 40-50% load factors. Similarly, prices paid by these high load factor customers is about 80% of the per unit price paid for customers with 40-50% load factors. In short, SGS-TOU is working quite well in providing a pricing signal across load factors that reflects embedded costs.

MGS shows some opportunity to improve price/cost alignment, particularly for customers with very low load factors. Such outcomes can be investigated in subsequent rate cases to determine if pricing adjustments in demand vs. energy charges or other rate design features can improve alignment.

**DEP – Large General Service Time-of-Use (LGS-TOU)**

Similar to the analysis above for SGS and MGS customers, the Company evaluated the alignment of price with embedded costs within LGS-TOU, normalized to the 50-60% load factor range. Customers tend to favor LGS-TOU when their load factors exceed 70%, which is higher than was typical for MGS and reflective of the class overall. Figure 20 below demonstrates that LGS-TOU pricing declines generally commensurate with embedded costs as load factors increase within the class.

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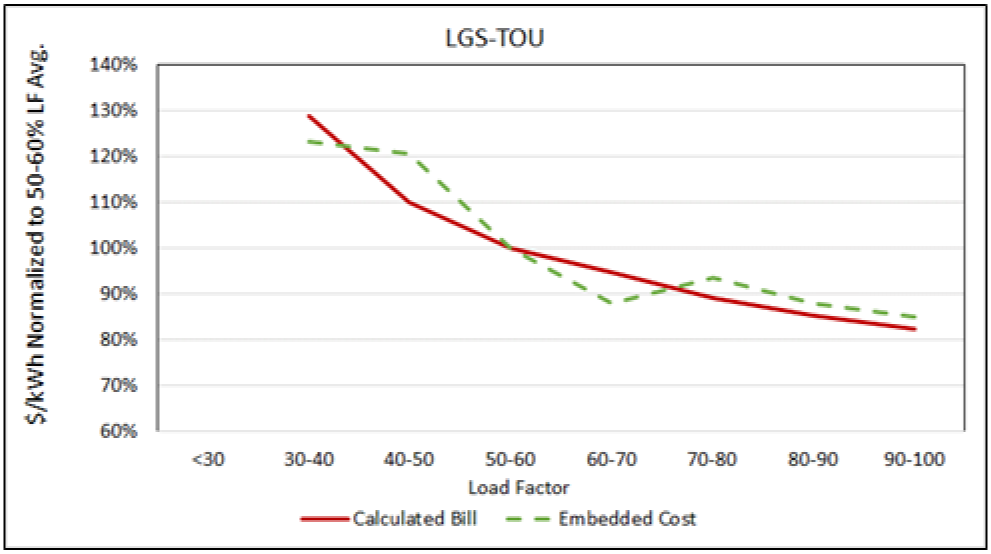


Figure 20: Relationship of Price to Embedded Cost for DEP's Current NC Large General Service TOU Rate

The Company followed the same process in the evaluation of DEC's OPT-V tariffs, with Primary and Secondary delivery for Large and Medium customers shown in Figures 21 and 22 below. In contrast to the DEP analysis above, the Company notes opportunities to improve in a few areas.

1. OPT-V Primary Large embedded costs drop considerably with rising load factors, consistent with SGS-TOU as described in the prior section. However, per unit of energy prices do not decline commensurately, leaving some opportunity for rate design improvements. Increasing the extent to which fixed costs are recovered through demand charges is one option to improving price/cost alignment. (OPT-V Primary Medium, in contrast, shows pricing aligned quite well with embedded costs across the range of load factors.)
2. OPT-V Secondary presents similar opportunities to improve as OPT-V Primary. Customers with higher load factors pay less per unit of energy than customers with lower load factors, but not as much as might be justified based on embedded cost differences. Rate designs in future rate cases could work to address these pricing differences through the mix of cost recovery via demand vs. energy or other rate design features.

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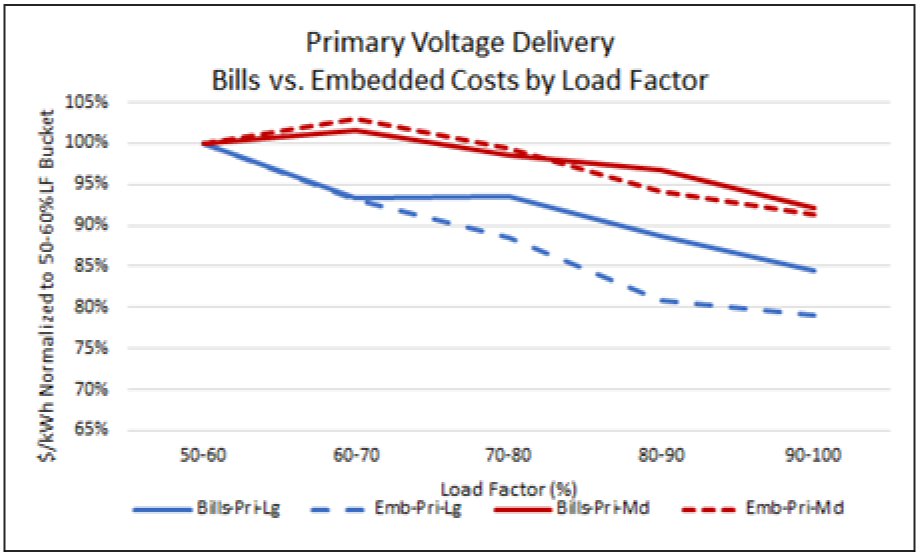


Figure 21: Relationship of Price to Embedded Cost for DEC's Current NC OPT-V Primary Medium and Large General Service Rates

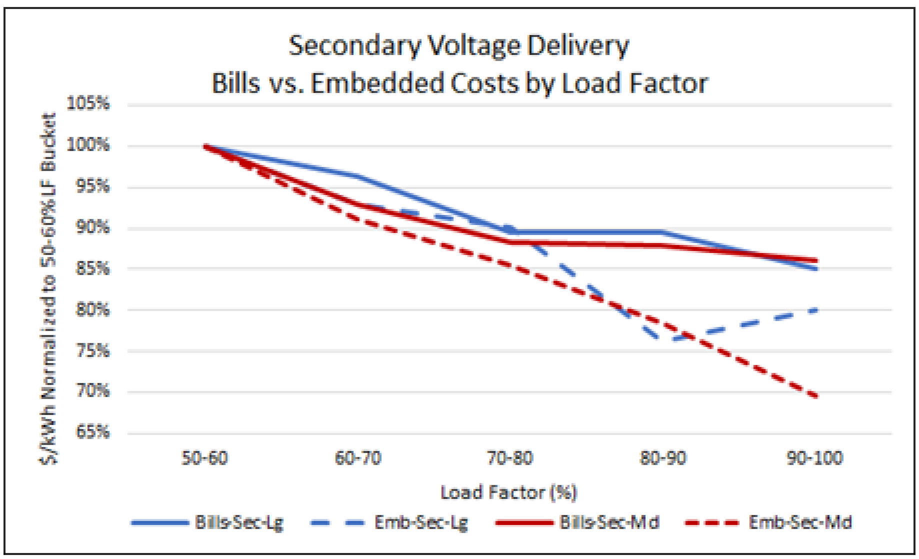


Figure 22: Relationship of Price to Embedded Cost for DEC's Current NC OPT-V Primary and Secondary Medium and Large General Service Rates

Importantly, as described elsewhere, the TOU periods and demand charge structure for these non-residential rates should be modernized to reflect today's electric system realities. Such improvements should better align embedded costs and pricing for individual customers based on differences in usage profiles. While the graphs above show some opportunity to improve for groups of customers, new TOU periods would begin to better distinguish between usage profiles and price. The Company will continue evaluating and consider improving such alignment over successive rate cases.

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## 6.2 Opportunities to Improve Alignment of Cost-Causation with Price

Rate designs should adjust to recognize changes coming from two fundamental factors – the upending of historic system operational norms and the increasing desire from customers to align price signals with usage behavior, particularly with respect to adoption of distributed energy technologies. Accordingly, non-residential rates should also be modernized to properly align pricing with cost-causation, thus ensuring energy investment and consumption decisions receive the appropriate economic signals with respect to system costs and potential impacts to other customers. The following areas require critical advancements and modifications to update the Companies' historic suite of rate offerings for these new realities.

Stakeholders expressed concern that TOU changes might increase bills for customers with inflexible loads

**TOU Period Modernization:** As mentioned above, TOU modernization forms the foundation for many rate design opportunities discussed in this Roadmap, in particular advancing the goals of better alignment between price signals (and bills paid) with cost-causation. The Companies reviewed the potential changes to non-residential rates with CRDS participants in the non-residential working group, including the implications that modernizing TOU periods will have for most of the other rate design ideas presented in this Roadmap. CRDS participants expressed concerns regarding the impacts across the spectrum of customer usage profiles. Accordingly, in creating prices for the new periods, the Companies will need to consider the disparate potential impacts between customers with flexible loads vs. those with operational challenges that do not permit load shifting, as well differences across varying load factors. The Companies discussed options for mitigating those concerns with customers and stakeholders and recognize that ultimate rate designs proposed in future regulatory proceedings must carefully weigh rate gradualism and concerns about unintended consequences, as well as maintaining non-TOU rate options for customers that would not benefit from being on a TOU rate. The Companies will use migration studies and near-population level analyses based on interval data to better understand how new revenue neutral rate design changes might result in a range of impacts across specific customers in some rate classes.

Notwithstanding important transition considerations, TOU period reform requires significant design changes across several of the Companies' tariffs that include time-differentiated pricing. Figure 23 lists the non-residential tariffs that would need to accommodate the new TOU periods.

| **DEC-NC** | **DEP-NC** |
|---|---|
| OPT-V | SGS-TOU, SGS-TOUE |
| PG | SGS-TOU-CPP *(modernized periods already)* |
| SGSTC *(modernized periods already)* | LGS-TOU, LGS-RTP-TOU |
| | CH-TOUE, SGS-TES, APH-TES |

Figure 23: Tariffs that would be updated through Time-of-Use Period Modernization

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**Demand Charges Restructuring:** As described in Section 4.2, demand charges must be reimagined to create cost-based price signals that match the new TOU periods. The three-part demand charge structure described in this Roadmap is an example of improved alignment to cost causation and equitable pricing for customers, for both those who adopt distributed energy technologies and those who do not. Stakeholders in the CRDS have shown significant interest in aligning capacity costs with demand charges as well as improving the alignment of cost-causation with pricing, particularly for high load factor customers. Implementing a new demand charge structure for TOU rates, such as the three-part demand charge structure, will be foundational to align costs with new TOU periods and better align time-period price signals with specific electric system asset utilization and, accordingly, costs. Increasingly, intermittent resources are reshaping grid cost profiles such that load factor is only one lens through which to view the efficient use of system resources. As an example, consider flexible loads, such as a fleet EV charging customer who constrains charging activities to only the Companies' proposed discount charging periods. Such a customer would have a very low load factor, but costs for production and transmission would be much lower than for a customer with a comparable load factor but with on-peak demands. As a result, even a low-load factor customer with certain usage profiles should receive appropriate system-reflective price signals. The three-part demand structure creates the framework by which price and system cost alignment can be maintained or improved gradually over time.

**Adjustment of Demand Tiers:** LGS-TOU and OPT-V Primary Large both currently have demand tiering features with lower $/kW charges for demand above certain kW thresholds. Such features account for cost differences associated with system use efficiency, but as described in the previous section, such pricing features may overlap with the restructured demand charges. The Companies explored one approach to retaining and adapting demand tiers to the new TOU periods during the CRDS, and further consideration will be needed, including considerations of rate gradualism, as the demand structures are evaluated in future regulatory proceedings.

**Capacity Related Costs in Demand Charges:** Several stakeholders suggested recovering more capacity-related costs in demand charges rather than energy charges, to better reflect cost drivers within the electric system. Importantly, the Companies believe such recovery should reflect the extent to which those capacity costs are driven by peak or non-peak costs, with recovery flowing through peak or mid-peak demand charges as appropriate. As noted above, expanding cost recovery through demand charges would help with price and cost alignment for DEC's OPT-V rates, and should be considered in future regulatory proceedings. Such changes would improve structural harmonization between DEC and DEP tariffs but must consider the potential for unintended consequences on customers across a variety of usage profiles. Thus, the Company would consider gradualism and perform detailed analysis across the rate class to support such modifications.

**Voltage Differentiated Rates:** While DEC's OPT-V tariff is divided up based on customer delivery voltage and load size, DEP uses load size to delineate between Small, Medium, and Large General Service classes. LGS-TOU provides a price differential for customer-supplied transformation as well as demand tiers, reflecting a typical correlation between size and delivery voltage. Size, delivery voltage, and load factor are all important considerations in creating customer classes, but the overarching objective is to align price with cost causation

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using a simple approach. Voltage-differentiated rates may be considered long-term for DEP, but at present the Company sees decent alignment between price and embedded cost across varying load factors (see Section 6.1). The benefits and complexities of additional pricing differentiation, including based on voltage delivery, will be evaluated and considered over successive regulatory proceedings.

**High Load Factor Rates:** Finally, some stakeholders in the CRDS advocated for rates designed for customers with higher load factors. The Company explored this idea in Working Group sessions and in several conversations with interested stakeholders and is continuing to evaluate the opportunity for possible inclusion in future regulatory proceedings, in addition to the adjustments referenced above with respect to load factors. While one approach may be to adjust demand charges and the mix of recovery between demand and energy to better align with cost-causation, another approach may be an entirely different tariff designed with demand charge structures suitable for high load factor customers.

The preceding ideas are interrelated and overlapping and cannot be considered in isolation. Indeed, good rate design requires consideration of the full set of changes together, considering the impacts to revenue requirements for the full class as well as individual customers within a particular tariff. The analytics capabilities the Company has developed will help ensure balanced and intentional outcomes for customers considering the balance of benefits from more precise pricing, rate design simplicity, and rate gradualism.

**Emergency Interruptible Rates:** The Company discussed an option for an additional interruptible rate to be used during system emergency conditions, possibly when response times are more rapid than current demand response programs. Additional program attribute design and valuation would need to be developed looking specifically at the unique characteristics of the Companies' system. In addition, potential overlap between other dynamic pricing options (Critical Peak Pricing and Hourly Pricing) would need to be considered.

**Peak Demand Rates:** A minority of stakeholders also put forward alternative approaches to demand structures in new rates, such as a non-residential Critical Peak Pricing rate or a Coincident Peak Pricing rate. Broad support for such structures was not expressed, with generally stronger preference for other alternatives (e.g. new Hourly Pricing Rate concepts discussed below). The Company will consider the alternatives with stakeholder preferences in mind, as well as considering how the characteristics of the Companies' system have evolved over the last several decades.

**Load Aggregation:** One stakeholder presented and advocated for Load Aggregation as a potential option to recognize the volume purchases made by customers with facilities located across the Companies' system. The Company discussed options to address such a design considering the modernized demand charge approach outlined above. The concept suggested by the stakeholder would allocate generation and transmission costs based on the aggregated load shape, which would reflect any load diversity, and would allocate distribution costs using the non-aggregated load.

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The preceding rate design concepts are interrelated and cannot be considered in isolation. Indeed, good rate design requires a holistic view, considering the impacts to revenue requirements for the full class as well as individual customers within a particular tariff. The analytics capabilities the Company has developed will help ensure balanced and intentional outcomes for customers considering precise pricing, rate design simplicity, and rate gradualism.

## 6.3 Expanded Hourly Pricing Options for Non-Residential Customers

The Companies' current hourly pricing programs provide hourly prices for incremental loads based on the Companies' marginal cost of generation. Both DEC's Hourly Pricing tariff and DEP's Real Time Pricing tariff are capped based on the number of participants. Customers and Stakeholders in the CRDS process have requested an increase in availability for these tariffs, as well as certain other options for flexibility with respect to the setting of Customer Baseline Loads (CBL). CBL's determine the amount of a customer's load that is priced at the marginal rate, with the core tariff being applied to the CBL for each customer's bill, and marginal energy prices either being charged or credited to the customer based on usage above or below the CBL, respectively. Importantly, an expanded hourly price tariff with significant levels of price-responsive load could be an important enabler for the Companies' Carolinas Carbon Plan, in addition to its other merits.

Stakeholder suggestions to modify the hourly pricing offerings discussed in the CRDS included the following:

- Expanded availability to more customers
- Allow existing load to take advantage of hourly (marginal) pricing
- Reduced complexity for setting and adjusting the CBL (simple, less restrictive, more frequent)
- Transparency in pricing and cost drivers
- Hourly pricing rates that considered EV charging and smaller customer participation

The Company provided an overview and responded to questions on hourly price derivation during the CRDS working sessions with stakeholders, providing increased transparency as to the derivation and basis for hourly prices. The remaining stakeholder suggestions were discussed in the context of a possible new hourly price offering. Importantly, the Company made clear that participants in a marginal price rate should not be able to avoid paying embedded cost-based rates if participating load was not truly incremental; in other words, if the load contributes to construction of new peak production and transmission resources. Accordingly, the discussion stressed the tradeoff between CBL flexibility and price responsiveness during times of grid constraints. As a result of those customer discussions, the Company suggested a possible new tariff that balanced customer desires for broader access to marginal pricing with consideration for possible impacts to the system and non-participating customers. This is particularly acute as it relates to recovery of embedded capacity costs and the needed alignment to the cost to provide service. The attributes of a potential new offer were generally described as follows:

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- **Availability:** Consider lower demand thresholds as compared to the current 1MW. Such broad expansion was proposed by a minority of stakeholders and should be balanced against the complexity and administrative burden of hourly pricing tariffs, as well as the availability of similarly beneficial options for many customers, such as Economic Development tariffs or core tariffs with revised TOU periods. Additionally, possible interest for smaller commercial and industrial customers would need to be evaluated given the complexity and price-responsive design elements described below.
- **Participation Limits:** Evaluate participation limits, currently set at 85 customers for LGS-RTP (DEP-NC) and 150 customers for HP (DEC-NC).
- **CBL Establishment:** Include a process for reestablishing the CBL every 4 years and adjustments based on the customer's 12-month usage history. Under the current tariffs and practices, CBL adjustments are not required on any set frequency. Importantly, the approach discussed would have the following implications for CBL establishment:
  - Growing loads with an inability to be price-responsive would receive marginal pricing for the incremental loads for only a limited time. Without the benefits of responsiveness to times of grid constraints, new capacity resources would ultimately need to be constructed for such loads, thus the CBL would be adjusted accordingly.
  - For loads that responded during periods of grid constraints, the CBL could be maintained lower based on the extent to which a customer reduced such loads during times of constraint.
  - The specific methodology for adjusting the CBL for price-responsiveness would need to be established in detailed program design.
  - The structure enables existing/historic loads to take advantage of marginal pricing provided such loads cease contributing to peak system demands during times of transmission and generation constraints, demonstrated by actual price-responsiveness over a period of time. Price-responsive behavior is system beneficial and reduces the extent to which such loads contribute to long-run marginal costs. In contrast, CBLs would increase to cover loads that are not price-responsive.
- **CBL Management:** DEC's process for CBL management is simpler and less administratively burdensome than DEP. Any new hourly pricing program would need to reflect a simpler approach in order to increase availability.
- **Energy Marginal Pricing:** The Company presented several variants of Hourly Pricing rates that would continue to enable embedded cost recovery but expand participation, including putting some margin as an adder to the energy prices. Stakeholders generally preferred to maintain the current approach of keeping the energy margin adder very small and recovering embedded costs through demand charges.
- **Existing and Incremental Loads:** As described above, stakeholders wanted the Company to consider allowing participation from both existing loads and incremental loads, which would require the CBL adjustment considerations outlined above.

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## 6.4 Simplification of Non-Residential Rates

For historical reasons, DEC and DEP have different approaches to Non-Residential rate designs and rate classes, with DEP generally using broad customer classes separated by size, and DEC using more narrowly defined customer classes separated by size, delivery voltage, and other factors. Both approaches are valid and indeed both often result in similar outcomes and impacts to customers; nevertheless, improvements and changes are appropriate to both simplify and modernize the tariffs as well as harmonize differences between the Companies. Figures 24 and 25 below provide considerations for specific improvements across the Companies' suite of non-residential rates.

Figure 24: Duke Energy Progress NC Non-Residential Tariff and Future Design Considerations

| Existing Tariff | Preferred Direction | Review Considerations |
|---|---|---|
| **Small General Service Class:** | | |
| SGS | Remain same | No change |
| SGS-TOU-CPP | Remain same | No change (newly available tariff with modernized TOU periods) |
| SGS-TOUE | Modify | Redesign TOU periods (no demand charges in tariff) |
| SGS-TOU-CLR | Remain same | No Change; consider need to remain separate from SGS |
| **Medium General Service Class:** | | |
| MGS | Remain same | No Change |
| SGS-TOU | Modify | Modernize TOU periods and demand charge structure |
| CSE | Modify | Modify price to encourage migration, per prior settlements |
| CSG | Modify | Modify price to encourage migration, per prior settlements |
| CH-TOUE | Modify | Modernize TOU periods |
| GS-TES | Modify or Replace | Replace with modernized TOU periods and demand charge structure, *or* Replace with modernized SGS-TOU and LGS-TOU |
| APH-TES | Modify or Replace | Replace with modernized TOU periods and demand charge structure, *or* Replace with modernized SGS-TOU and LGS-TOU |
| **Large General Service Class:** | | |
| LGS | Remain same | No Change |
| LGS-TOU | Modify | Modernize TOU periods and demand charge structure |
| LGS-RTP | Replace | Replace with new Hourly Pricing Option with greater availability |
| LGS-RTP-TOU | Replace | Replace with new Hourly Pricing Option with greater availability |

Figure 25: Duke Energy Carolinas NC Non-Residential Tariff and Future Design Considerations

| Current Rate Schedule | Direction | Review Considerations |
|---|---|---|
| **General Service Tariffs:** | | |
| SGS | Modify | Simplify Energy Block structure |
| SGSTC | Remain same | No change (newly available tariff with modernized TOU periods) |

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| | | |
|---|---|---|
| BC | Remain same | No change |
| I | Modify | Evaluate Block structures for simplification |
| LGS | Modify | Evaluate Block structures for simplification |
| OPT-V | Modify | Modernize TOU periods and demand charge structure |
| PG | Modify | Modernize TOU periods and demand charge structure |
| HP | Replace | Replace with new Hourly Pricing Option with greater availability |

## 6.5 Non-Residential Net Energy Metering Reform

As described above, the Companies recently filed a proposed NEM reform for residential customers in NC based on collaborative outcomes in the CRDS.[16] The Company also discussed possible changes and improvements for non-residential NEM policies with stakeholders during the CRDS. The following NEM elements were discussed with stakeholders and could be considered in the context of future regulatory proceedings.

- **Expand Capacity Limits:** Currently, for DEP customers, NEM systems are limited to "the lesser of Customer's estimated maximum annual kilowatt demand or 1,000 kilowatts." DEC presently limits non-residential system sizes to the lesser of the Customer's Contract Demand or 1,000 kW.[17] Consideration should be given to harmonizing the approach between the utilities. Stakeholders have requested the 1MW limit be raised. As mentioned above, the Companies note that restructuring demand charges to a 3-tier approach as described above could provide cost alignment sufficient to consider raising the limits as requested by stakeholders. Additionally, the new TOU periods could similarly address cost recovery concerns stemming from differing energy values across time periods.
- **Review Standby Charges for Solar Facilities:** Stakeholders have expressed interest in having the standby charge practices of the Companies reviewed, and such changes would impact both solar and non-solar resources. Indeed, HB951 requires the review of such charges. The Company is undertaking such a review at present, in light of the changes related to fixed-cost recovery associated with the demand charge structure modernization described above.
- **TOU Rate Participation:** The Company's proposed residential NEM reform included a requirement that residential NEM customers take service under a TOU-CPP tariff. Similarly, the Company could consider a requirement for non-residential NEM customers to take service under a TOU demand rate with the view toward achieving appropriate economic consideration for the value of the solar resource.
- **Revise Netting Periods:** Consideration should be given to following the netting approach proposed in the Companies' residential NEM reform application, which nets energy within each TOU period.
- **Renewable Energy Certificate (REC) Retention:** NEM Customers taking service under one of the Company's TOU tariffs will retain ownership of all RECs generated by their system. *[The Companies will*

[16]See Joint Petition for Approval of Revised Net Energy Metering Tariffs, filed on November 29, 2021 in Docket Nos. E-7, Sub 1214; E-2, Sub 1219 and E-2, Sub 1076 but subsequently transferred by the Commission to Docket No. E-100, Sub 180.
[17] The 1,000kW limit applies to NEM customers. Customers wishing to install more than 1,000kW must do so under an alternate tariff, for example DEC-HP or DEC-PG.

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*work to align REC ownership rules across NC and SC, including consistency with outcomes from the NEM reform activities.]*

- **Accommodate Energy Storage:**
  - Some stakeholders would like to see a program that incorporates energy storage for demand response or grid service credits.
  - NEM needs to clarify whether batteries count as part of the generation system or load, and the answer may depend on where in the system the battery is electrically located.
  - Clarity here is needed for customers wish to be "net-zero." The Companies' Large Account Managers (LAM) and Rates teams increasingly encounter such requests and more clarity is needed on what is allowed.
- **Minimum Bill:** The Companies will evaluate the extent to which a minimum bill is needed for customers on a non-demand rate, such as DEP-SGS and DEP-SGS-TOUE.

## 6.6 Economic Development

The Companies received meaningful and helpful proposals and feedback from stakeholders in reviewing current Economic Development tariffs and potential improvements. Figure 26 below shows the differences in the current DEC and DEP Economic Development tariff options. Considerations for improvement are provided below, including many recommendations from stakeholders on specific elements to include and/or adjust. Overall, the suggestions provide more flexibility to offer credits based on the merits of specific growth opportunities. Ultimately, expanded load through economic development can reduce the prices paid by all customers, through contribution to fixed cost recovery, and promotes the prosperity of the citizens and businesses in the Companies' territories. Some combination of the improvements discussed would assist the State of North Carolina and local communities in competing for projects.

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| Rider Attribute | Econ Dev. (DEC – EC) | Econ Re-Dev. (DEC – ER) | Econ Dev. (DEP – ED) | Econ. Re-Dev. (DEP – ERD) |
|---|---|---|---|---|
| Availability | • 1,000 kW min.<br>• LGS, I, OPT-V<br>• Excl. Retail, Pub. Admin. | • 500 kW min.<br>• LGS, I, OPT-V<br>• Excl. Retail, Pub. Admin. | • 1,000 kW min.<br>• LGS & LGS TOU<br>• Excl. Retail, Pub. Admin. | • 500 kW min.<br>• MGS, SGS-TOU, LGS, LGS-TOU<br>• Excl. Retail, Pub. Admin. |
| Qualification | 75 FTEs or $400k capital invested per 1,000kW | 35 FTEs or $200k capital invested per 500kW | 75 FTEs or 1FTE + $400k capital invested | 35 FTEs or 1FTE + $200k capital invested |
| Location | New or existing building | Existing building | New or existing building | Existing building |
| Discount | 4-yr. declining discount from 20%→5% | 50% for 12 months | • 5-yr. declining $/kW<br>• Scales w/ LF (>40%) | • 1-yr.; 25% if <1MW, 50% if >1MW<br>• LF >40% only |
| Ramp Period | 18 months | 12 months | 18 months | 12 months |
| Contract Term | 10 years | 5 years | 5 years | 5 years |
| Termination Penalty | Lower of NPV of remaining Min Bills or LDER + difference between Credits and Marginal costs | Lower of NPV of remaining Min Bills or LDER + difference between Credits and Marginal costs | Return all discounts | Return all discounts |

Figure 26: Key Attributes of DEC and DEP Current Economic Development Tariffs

- **Availability:** Availability criteria regarding size, load factor, and other considerations were discussed. As mentioned above the Company's Economic Development tariffs could be modified to lower availability thresholds and exemptions for the employment requirements for EV fleets. Stakeholders also proposed possible expansion of participation availability to include customers where retention of load and employment is at risk, such as efforts to modernize or reinvest in plant or equipment where such investment could be competitively relocated outside the Companies' service territories. The Company may explore ways to address such situations where NC may otherwise be placed at a competitive disadvantage, recognizing that additional qualification criteria may be required for such circumstances (e.g. capital investment levels, etc.).
- **Qualifications:** Qualifications are important to ensure the incremental loads are system-beneficial for an extended period and will ultimately provide benefits to all customers. Stakeholders offered a variety of suggestions regarding employment, investment levels and participation in renewable or green programs. The Company will consider these criteria, as well as possible changes to the discount structure outlined below. To the extent credit levels become flexible with respect to project-specific attributes, the importance of qualifications as threshold barriers decline. In addition, the North Carolina Department of Commerce offers Job Development Investment Grants (JDIGs) for High Yield Project (HYP) status for creation of 1,750 jobs and $500M investment in NC and Transformational Project (TP) status for creation

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of 3,000 jobs and $1B investment in NC. The Company will consider the merits of additional support for Economic Development projects meeting these Department of Commerce criteria.

- **Discount Credit Level:** DEC's present credit approach is essentially one-size-fits-all, while DEP's approach scales with load factor under the assumption that system benefits of new projects increase given the more efficient asset utilization. Similarly, other project attributes also warrant consideration for determining the scale of credit levels. During the CRDS, the Company presented the example of Duke Energy Indiana's economic development tariff which scales the credit based on several factors, similar to those in the list below. Additionally, the credits can be tailored across the duration of the incentive period to reflect specific needs or attributes of each project. As such, the Companies may consider proposing credit levels that could vary by year and reflect the following value factors for each project:
  - Peak monthly demand
  - Average monthly load factor
  - The Company's incremental costs to serve
  - Number of new FTEs
  - Economic multiplier (e.g. supply chain impacts upstream for OEM)
  - Total new capital investment of the customer
  - Others as appropriate
- **Ramp Period:** The Ramp Period allows a customer who elects to participate in the Economic Development program to defer initiation of the credits for a time during the startup operational phase. Some industries have significant startup periods that extend beyond the currently allowed 18-month window. CRDS participants discussed the possibility of a 36-month ramp period, which would provide a more meaningful credit to customers with extended start-up timeframes, which usually correlates to significant customer investment (and thus worthy of extra consideration). Without such expansion, some customers may effectively lose the entire first year or more of the benefit from the ED rider.
- **Contract and Termination:** DEC's current contract term of 10 years is longer than DEP's 5-year term. Given the increase in flexibility and potentially flattening of credits across the term, the Company will consider lengthening the contract term to 10 years, further yielding consistency between DEC and DEP. Similarly, the early termination penalty could be simplified and made consistent across DEC and DEP. Finally, the Company will consider provisions for longer duration credits and contract terms for projects that may merit such consideration.
- **EVs:** During the CRDS, stakeholders expressed an interest in Duke Energy working directly with non-residential EV customers – both EV fleets and owners of charging stations – to address their needs. As mentioned above, one concept considered removing possible barriers for such loads to participate on economic development tariffs. The Company may consider changes to qualification criteria specific for such incremental loads, for example, reducing the employment thresholds. Additionally, any economic development benefit to these customers will need to consider possibly overlapping benefits from Make-Ready or marginal-cost-based pricing options to ensure that these policies do not enable "double-dipping" (i.e. giving multiple benefits for the same system benefit).

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## 6.7 Renewable and Clean Tariffs and Programs

Throughout the course of the CRDS, the Company engaged with several interested customers and advocacy groups to explore possible new or expanded renewable or clean energy programs and offers. In accordance with HB951, the Company would pursue such programs to the extent non-participants are held harmless and supporting resources are developed in accordance with state policy. While the Company recognizes some elements of bill credits and recovery may need to be addressed for the program designs being considered, the Company sees the following desirable program attributes:

- Participating customers are able to own/purchase RECs for desired renewable energy levels
- Customers could have optional access to storage resources as part of the program to time-align consumption of renewable or clean energy
- Flexibility to adjust for the diverse sustainability goals within Duke Energy's current customer base as well as prospective Economic Development opportunities

The Company will continue conversations with interested customers in order to ensure future programs are sufficiently flexible and durable, meeting the needs of a broad mix of interested customers as well as complying with HB 951 requirements.

## 6.8 Historic/Closed Tariffs

The Company reviewed a few historic rates that have low participation or are currently frozen to new participants. Additionally, new program offerings such as modernized TOU offerings and an expanded and revised hourly pricing option create opportunities to close and/or freeze existing tariffs, such as the following:

- **Real Time Pricing (DEC-HP, DEP-LGS-RTP and DEP-LGS-RTP-TOU)** – To the extent the Company moves forward with the new hourly pricing option as described above in future regulatory proceedings, the existing DEC-HP and DEP-RT hourly pricing options should be evaluated for freezing to new customers. As such, noted administrative challenges and program limitations would be addressed.
- **Small General Service Constant Load (DEP-SGS-TOU-CLR)** – The Company may consider the need to retain tariffs, such as the Constant Load tariff, in light of the capabilities now present with AMI metering and also the planned modernization of TOU periods and demand charge structures.
- **Church and School Service Tariffs (CSE and CSG)** – These two tariffs have been closed to new customers since 1977 and have a dwindling number of participants. To the extent the modernized tariffs with new TOU periods present savings opportunities to CSE and CSG customers, the Company may move customers to the new rates (per the terms of the tariffs), providing the opportunity to close these historic tariffs.
- **Church Service TOU (CH-TOUE)** – The Company will need to consider either redesigning this tariff with the new TOU periods or closing the tariff to new customers. Consideration would likely include an analysis of the extent to which the redesigned SGS-TOU rate might be a favorable alternative for customers presently taking service on CH-TOUE.

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- **Thermal Energy Storage Tariffs (SGS-TES and APH-TES)** – These tariffs were designed for customers using thermal energy storage systems. As the modernized demand structures and TOU periods described should address economic use of other forms of storage, the Company should evaluate the ongoing need for these tariffs given the redesigned core tariffs in upcoming regulatory proceedings.

For the rates listed above, customers could migrate to another alternative core rate, as appropriate (for example, SGS-TOU or OPT-V). Overall, the Companies prefer a simplification for the overall suite of rate offerings, but with meaningful options remaining based on the customers interest in TOU, demand, or dynamic pricing schedules – all of which would have improved price signals with the changes envisioned in this document.

# 7 Timeline for Implementation of Rate Design Changes

## 7.1 Timeline for Changes and Improvements

Throughout the CRDS, the Company stressed a bias for action, specifically preferring to advance the changes that improved options and addressed issues for the most customer as soon as possible. Many of the items discussed will need to be addressed in the context of a rate case, but others are able to be advanced more quickly or in other proceedings. The following areas presented opportunities to pursue improvement more quickly.

**DEP TOU-Critical Peak Pricing (R-TOU-CPP) Rate:** Filing in September 2021 consistent with the new TOU periods and in an effort to increase customer options for dynamic rate structures.

**Net Energy Metering:** As a result of the CRDS process, on November 29, 2021, DEC and DEP jointly filed a Petition for Approval of Revised Net Energy Metering Tariffs (Docket Nos. E-7, Sub 1214; E-2, Sub 1219 and E-2, Sub 1076). The proposed reforms will align solar adopter compensation to utility system benefits and create long-term stability for the residential solar industry in North Carolina. The agreement was crafted by Duke Energy and NCSEA; the SELC on behalf of Vote Solar and SACE; Sunrun Inc. and the Solar Energy Industries Association and must be approved by the NCUC.

**Residential Tariff Availability:** As a result of the CRDS process and customer feedback, on December 16, 2021, DEC filed Proposed Revisions to Service Regulations and Rate Schedules (Docket No. E-7, 1214). The proposed changes to the Availability provisions of certain residential tariffs removes the requirement that facilities be permanent, thus reflecting a more liberal application of residential rate provisions as part of the resolution of the "tiny homes" issue. The Company proposed revisions to its Service Regulations to allow eligible tiny homes to be billed on a residential schedule, which DEP Service Regulations currently allow. The proposed changes must be approved by the NCUC.

**Freezing DEC Rate RT:** The Company proposed and has received approval to freeze DEC Rate RT to new participants as of April 1, 2022 in an effort to improve TOU period alignment across the suite of tariff offerings and reduce customer impacts for customers on TOU based rates when such transitions occur.

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**EV Managed Charging Pilot:** As described in Section 4.4 above, The Companies recently filed a Residential EV Managed Charging pilot application with the NCUC in Docket No. E-7, Sub 1266 for DEC and Docket No. E-2, Sub 1291 for DEP.

In the medium to long term, the Companies will pursue opportunities through rate case proceedings in North Carolina to propose rate design changes in alignment with the vision laid out in this Roadmap and allow for further stakeholder consideration and vetting of the proposed impacts prior to implementation.

# 8 Comprehensive Rate Design Study (CRDS)

## 8.1 Background and Initiating Orders

On March 31, 2021, the North Carolina Utilities Commission (NCUC) issued an Order directing DEC to conduct a comprehensive Rate Design Study and Roadmap to maximize the efficiency and effectiveness of new utility and customer technologies and their impact on the electric system.[18] The Order established specific topics, considerations, and timing for the rate design study (12 months), such as:

> *"The Commission finds that the Rate Design Study should: (1) include an analysis of each rate schedule to determine whether the schedule remains pertinent to current utility service, including whether the schedule should remain the same, be modified, or be replaced; (2) address the potential for new schedules to address the changes affecting utility service; (3) provide more rate design choices for customers; and (4) explore the feasibility of consolidating the rates offered by DEC and DEP." (p. 181)*

On April 14, 2021, the NCUC issued another Order addressing DEP rate case stipulations and including more details regarding Rate Design Study scope, for example, noting that cost of service allocation methods discussions with stakeholders were out of scope.[19] Finally, the Order directed Duke Energy to engage an independent third-party facilitator for the stakeholder portion of the CRDS. As such, Duke Energy contracted with ICF to facilitate the CRDS stakeholder engagement process and prepare quarterly status reports. Together, Duke Energy and ICF developed an overall project plan, timeline, and stakeholder engagement approach. The project plan and timeline can be seen in Figure 27 below, which shows key milestones such as filed quarterly reports, interviews, and forums for all participating stakeholders. The stakeholder collaboration and vetting of rate design concepts primarily occurred in topically focused working groups (WGs), as described below.

[18] NCUC Docket No. E-7, Sub 1214 – In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulations, Granting Partial Rate Increase, And Requiring Customer Notice* (DEC Order) (March 31, 2021).

[19] NCUC Docket No. E-2, Sub 1219 - In the Matter of Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulations, Granting Partial Rate Increase, And Requiring Customer Notice* (DEP Order) (April 16, 2021), p. 182.

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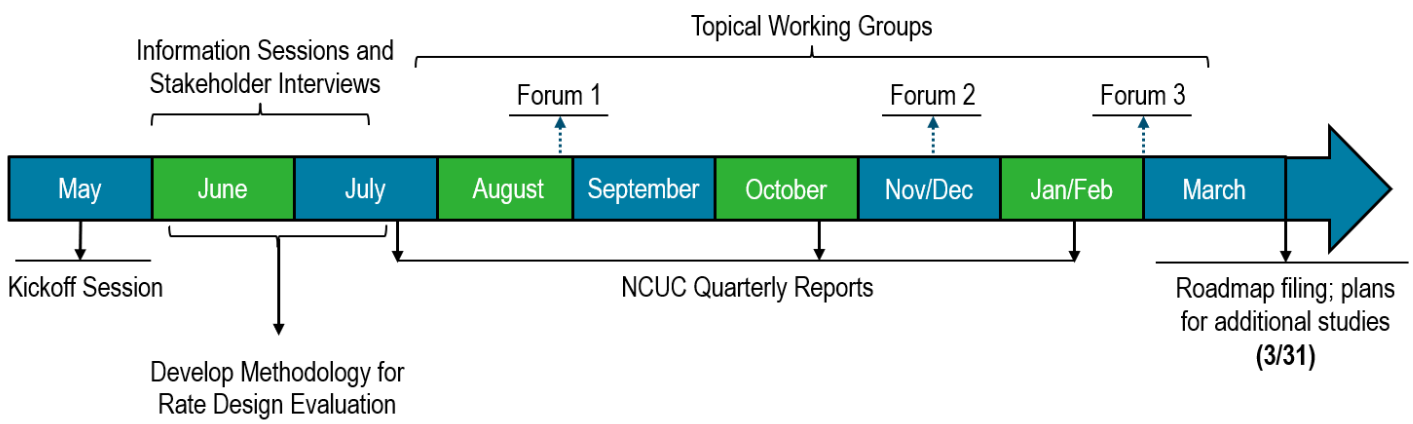


Figure 27: Comprehensive Rate Design Study High Level Timeline

Over the 12-month CRDS process, Duke Energy and stakeholders explored a list of rate design topics proposed in the NCUC Order and by stakeholders through interviews, surveys, and specific working group (WG) participation. This Roadmap Section describes the stakeholder engagement framework, CRDS participants, and activities.

## 8.2 Stakeholder Participation

ICF conducted extensive outreach at the beginning of the CRDS process to ensure that a broad range of stakeholder perspectives would be included. The stakeholders who participated in the CRDS spanned several sectors, such as commercial and industrial (C&I) customers, EV companies and advocates, environmental advocates, government agencies, public advocates, renewable/distributed energy resource (DER) companies, and legal/consulting companies. The list of stakeholders included the intervenors in the proceeding, per the NCUC Order; Duke Energy also extended participation to other interested parties not formally part of the proceeding. A full list of participating organizations by WG can be found in Appendix B.

The stakeholders had opportunities to participate in the process through WG discussions, forums, interviews, surveys, and individual outreach at their convenience. Some stakeholders offered to present on specific topics or case studies during their WG meetings (see Figure 28).

| Working Group | Stakeholder Speaker | Topic |
|---|---|---|
| **WG 1 - Fast Track Topics** | Environmental Defense Fund | Rate design for medium and heavy-duty electric vehicles |
| | Sunrun and Southern Environmental Law Center (SELC) | Historical context surrounding NEM reform |
| | NC WARN, Appalachian Voices, Advance Carolina, and The Center for Biological Diversity | NEM reform and perceived issues, including accessibility to clean energy economy for disadvantaged communities |

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| | | |
|---|---|---|
| **WG 2 - Hourly Pricing & Economic Development** | Carolina Industrial Group for Fair Utility Rates (CIGFUR) | Proposals for new economic development and jobs retention riders |
| | Utility Management Services | Case study on Virginia Electric and Power Company's Schedule 10 Large General Service rate |
| **W4 - Non-Residential Rates** | Kroger | Concept of load aggregation (also referred to as conjunctive billing) and potential benefits to customers with load at multiple locations through reduced generation and transmission charges. |
| | CIGFUR and NCSEA | Recent non-residential NEM changes in South Carolina |

Figure 28: Stakeholder presentations in CRDS Working Groups

In addition, during the three CRDS Study Forums, assigned stakeholders delivered activity updates for each WG. Figure 29 lists the stakeholders who reported out on behalf of their WG during the three stakeholder Forums.

| | **Stakeholder Speakers** | | |
|---|---|---|---|
| **Working Group** | **Forum 1 - Speakers** | **Forum 2 - Speakers** | **Forum 3 – Speakers** |
| **WG 1 - Fast Track Topics** | Thad Culley (Sunrun) | David Neal (SELC) | Elizabeth Stein (EDF) |
| **WG 2 - Hourly Pricing & Economic Development** | Justin Bieber (Energy Strategies, LLC, on behalf of Harris Teeter and Kroger) | Christina Cress (Bailey & Dixon, on behalf of CIGFUR) | N/A |
| **WG 3 - Residential Rates** | N/A | Benjamin Smith (NCSEA) | N/A |
| **W4 - Non-Residential Rates** | Christina Cress (Bailey & Dixon, on behalf of CIGFUR) | Justin Bieber (Energy Strategies, LLC, on behalf of Kroger) | N/A |

Figure 29: Stakeholder Speakers at CRDS Forums

## 8.3 Stakeholder Engagement Framework

The CRDS process systematically addressed rate design topics over the year-long effort to allow stakeholder engagement on each topic, dedicating additional time to topics as needed based on stakeholder's requests. Stakeholders were able to share their opinion through WG discussions, large group forums and were kept informed by receiving periodic email updates and quarterly status reports. Stakeholder engagement was central to developing the CRDS Roadmap. On April 30, 2021, Duke Energy initiated a process to engage parties across North Carolina and South Carolina in a comprehensive rate review process.[20] ICF and Duke Energy coordinated outreach and communication approaches to engage stakeholders participating in the CRDS. Initial surveys and

[20] NCUC Docket Nos. E-7, Sub 1214 and E-2, Sub 1219, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Notice of Rate Design Study Initiation (April 30, 2021).

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interviews informed the structure of each WG, its participants, and topics to cover. Figure 30 shows the four CRDS WGs and topics covered.

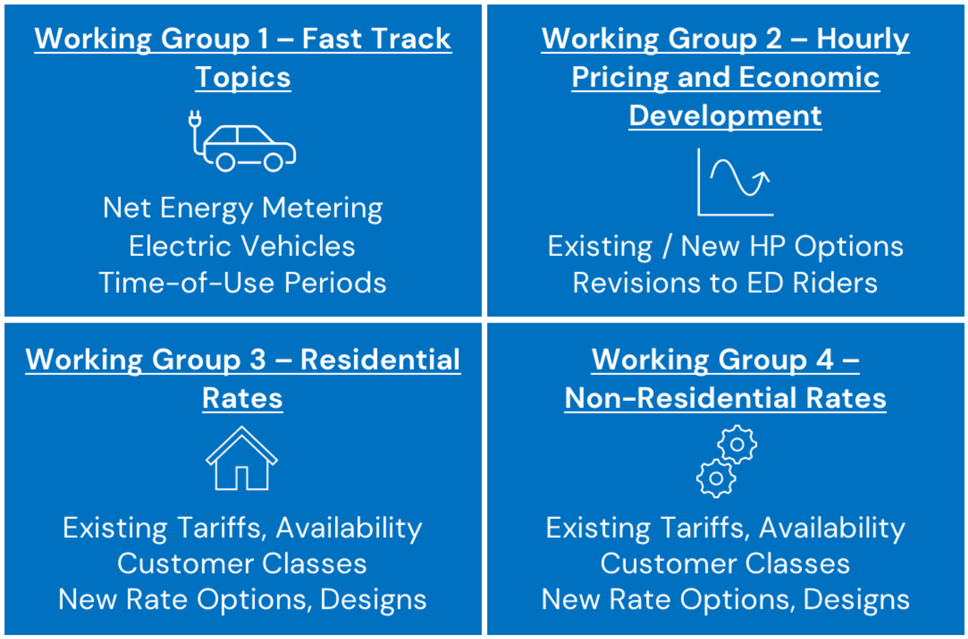


Figure 30: Four Working Groups Organized for Comprehensive Rate Review

The stakeholder process prioritized collaboration and opportunities to discuss the merits of rates and rate design options, including potential effects on all Duke Energy customers, seeking consensus where possible on rate design ideas to consider.

ICF served as the independent third-party facilitator for the stakeholder portion of the CRDS to coordinate stakeholder meetings and communications, and to ensure the process provided opportunities for all voices to be heard. Over the past 12 months, stakeholders were invited to participate through interviews, surveys, Working Group meetings, and forums.

Figure 31 provides an overview of how stakeholders were able to engage throughout the process.

| Method | Benefit |
|---|---|
| **Initial Interviews** | ICF Interviews with individual stakeholders to set expectations and prioritize ideas for consideration. |
| **Rate Design 101 Training Sessions** | Virtual informational sessions covering the ratemaking process, including fundamental principles of revenue requirements, cost allocation, and rate design. Sessions provided an overview of how cost of service relates to rate design as well as guiding principles for rate design. |

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| | |
|---|---|
| **Stakeholder Forums** | Three collaborative-wide meetings covering Working Group progress, items discussed, and considerations around ideas. Forums occurred on August 25, 2021, November 16, 2021, and February 10, 2022. |
| **Working Group Sessions** | Topically focused meetings with smaller numbers of participants that were often interactive and with agendas that varied based on stakeholder feedback. Many sessions included presentations by stakeholders on topics of interest. |
| **MURAL Boards** | Interactive collaboration tool used to gather stakeholder positions and feedback on rate design ideas. Boards were used during meetings for interactive Q&A and also as documentation of topics discussed. |
| **Subgroup Discussions** | Smaller sessions to discuss details or narrow design elements, typically between Duke Energy and 1-2 stakeholders, as requested by stakeholders or for topics not covered in larger Working Group Sessions. |
| **Duke Energy / Stakeholder 1:1 Discussions** | As requested by stakeholders, time to discuss particular ideas or understand potential implications to customers from rate design topics. |
| **ICF / Stakeholder 1:1 Discussions** | As initiated by stakeholders, opportunity to voice concerns over the process, ask questions about priorities, or seek additional means of communications. |
| **Rate Review Email Address** | Duke Energy-monitored email address used for material distribution and broad stakeholder communications. Stakeholders could request to be on the distribution list. |
| **Rate Review Information Portal** | Duke Energy website providing an overview of the process and access to materials distributed to the entire stakeholder group. |
| **Materials Distributions** | Forum presentations, Working Group slides, case studies, etc., were distributed for each session to allow for consideration and further questions by stakeholders. |
| **Periodic Stakeholder Digests** | At the suggestion of a CRDS participant, ICF and Duke Energy began issuing email digests during months when NCUC quarterly reports were not filed, providing short summarized updates on activities and progress made. |
| **Quarterly Reports** | Status reports of progress made and upcoming activities for the CRDS were filed with the NCUC on July 21, 2021, October 21, 2021, and January 21, 2022. |

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|---|---|
| **Working Group Surveys** | ICF leveraged surveys at initiation of Working Groups to determine priority of topics for discussion as well as at the conclusion to ascertain the extent to which topics were covered and identify potential gaps. |

Figure 31: Description of CRDS Engagement Channels

## 8.4 Summary of Engagement Activities

Stakeholder participation in the overall process was broad and included very engaged organizations. The Companies recognize and appreciate the level of effort, resource commitment, and constructive engagement from the many organizations and individuals interested in advancing rate design for the benefit of North Carolina's electric customers. Stakeholders participated consistently throughout the 12-month process, offering feedback, ideas, and questions throughout. Stakeholders were also flexible as calendars were stretched with other energy related activities and events, working with Duke Energy and ICF to ensure meeting times and communication channels that facilitated ongoing broad participation. Figure 32 summarizes the levels of engagement across the communication channels referenced previously.

| Engagement Channel | Engagement Statistics |
|---|---|
| **Rate Review Email Address** | Approximately 300 individuals registered to receive email notifications and updates on progress |
| **Initial Interviews** | 9 key stakeholders interviewed to understand priorities for topic focus and shape the engagement process |
| **Working Group Sessions** | 18 Sessions held across four Working Groups |
| **Subgroup Discussions** | 22 Subgroup Discussions held across four Working Groups |
| **Stakeholder Presentations at Working Group Sessions** | 7 Stakeholder presenters (non-Duke Energy and non-ICF) across the Working Group Sessions |
| **Stakeholder Presentations at Stakeholder Forums** | 8 Stakeholder presenters (non-Duke Energy and non-ICF) during the 3 Stakeholder Forums |
| **Surveys** | 8 Surveys issued across the Working Groups |
| **Periodic Stakeholder Digests** | 3 summaries of CRR activities distributed to stakeholders via email |
| **Mural Boards** | 20 Mural boards created to gather stakeholder feedback during WG sessions |

Figure 32: Summary of Completed CRDS Engagement Activities

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## 8.5 Working Group Sessions

ICF facilitated four working groups which included kick off sessions and between two and five rate design discussion sessions for each working group. In addition to the regular WG sessions, a total of 22 subgroup meetings were added during the process, based on requests for additional information, to dive deeper into specific topics, design attributes, or analytics. Figures 33-36 show the sessions and subgroup meetings for the four WGs. Also, 1:1 stakeholder discussions were held as needed or requested throughout the process.

| Date | Fast Track Sessions |
|---|---|
| 7/9/2021 | Kick-Off |
| 7/22/2021 | Subgroup A: Duke Energy TOU Period Proposal and Supporting Analytics |
| 7/29/2021 | Subgroup B: Stakeholder NEM Presentations |
| 8/5/2021 | Subgroup C: Duke Energy NEM Mechanics Proposal |
| 8/12/2021 | Session 1: TOU Rates and NEM Discussion |
| 8/19/2021 | Subgroup D: NEM Design Embedded and Marginal Costs Studies |
| 9/2/2021 | Subgroup E (NDA Only): Duke Energy Forecast Data Review |
| 9/14/2021 | Subgroup F: Final Discussion on TOU and NEM Proposals |
| 9/29/2021 | Session 2: EV Rates Discussion |
| 10/27/2021 | Subgroup A: Residential EV Rates |
| 11/4/2021 | Subgroup B: Non-Residential EV Rates |
| 11/10/2021 | Subgroup C: Residential EV Rates |
| 11/17/2021 | Subgroup D: Non-Residential EV Rates |
| 1/28/2022 | Subgroup E: Non-Residential EV Rates |

Figure 33: Fast Track Working Group Meetings

| Date | Hourly Pricing / Economic Development Sessions |
|---|---|
| 7/21/2021 | Kickoff |
| 9/15/2021 | Session 1: Existing Duke Energy RTP/HP rates and national case studies |
| 9/21/2021 | Subgroup A: Duke Energy presentation on marginal cost pricing analysis |
| 9/28/2021 | Subgroup B: Stakeholder Presentations<br>• Carolina Industrial Group for Fair Utility Rates (CIGFUR) presented their proposals for new Economic Development and Jobs Retention Riders.<br>• Utility Management Services (UMS) presented a case study on Virginia Electric and Power Company's Schedule 10 Large General Service rate, highlighting beneficial rate design elements and customer benefits. |
| 10/12/2021 | Subgroup C: Modified Economic Development Rider, Dynamic Pricing for Large Businesses, Expansion of HP rates |
| 10/19/2021 | Subgroup D: Duke Energy conducted a working session to solicit stakeholder feedback for HP rate solutions and CBL setting process. |

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|---|---|
| 11/2/2021 | Subgroup E: Duke Energy summarized the stakeholder objectives heard to date through the CRR and presented three rate design concepts: an expanded HP option, a new dynamic pricing rate option, and new Economic Development Rider. |
| 12/7/2021 | Session 2: ICF summarized the topics covered over the course of the 8 WG meetings. Duke Energy provided a requested overview of the current price derivation process for HP and RTP rates, and how the CBL impacts fixed cost recovery. |

Figure 34: Hourly Pricing and Economic Development Working Group

| Date | Residential Rates Sessions |
|---|---|
| 8/4/2021 | Kick-Off |
| 9/20/2021 | Residential Rate Overview |
| 9/27/2021 | Session 1: Existing Rates and TOU Proposal Review |
| 10/20/2021 | Session 2: HB 951, Permanent Foundation, Schedule RT, Fixed Charges and Analytics |
| 11/3/2021 | Session 3: DEP Analytics |
| 12/12/2021 | Session 4: Marginal cost details, minimum bill analysis, declining block rate, seasonal price difference, all electric option, demand charge TOU options |
| 3/11/2022 | Session 5: DEC Analytics and Whole Home Subscription concept |

Figure 35: Residential Rates Working Group

| Date | Non-Residential Sessions |
|---|---|
| 7/14/2021 | Kick-Off Session |
| 8/11/2021 | Session 1: Load factor-based rates and demand charges |
| 9/8/2021 | Session 2: Demand charges and demand response |
| 9/14/2021 | Subgroup A: Non-residential NEM policies |
| 9/15/2021 | Subgroup B: Aggregation of loads / conjunctive billing |
| 10/13/2021 | Session 3: Continuation of demand charge design issues and interruptible/curtailable rates |
| 12/1/2021 | Subgroup C: Case studies on load aggregation |
| 1/11/2022 | Subgroup D: Load factor rates |
| 1/27/2022 | Subgroup E: Review merit of current rates and customer class appropriateness; DEP marginal cost analysis |
| 2/15/2022 | Subgroup F: Demand charges; TOU rating periods impacts |
| 3/2/2022 | Session 4: TOU rates and Wrap up |

Figure 36: Non-Residential Rates Working Group

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## 8.6 Alignment with Other Duke Energy Stakeholder Collaboratives

While the CRDS was focused on rate design items in particular, thoughtful alignment and information sharing occurred between the CRDS and other collaborative stakeholder efforts focused on affordability and electric transportation. Rate design considerations from both parallel efforts were included in CRDS Working Groups as appropriate, and in some cases joint meetings occurred to ensure alignment and clarity for participating stakeholders. Notably, significant overlap existed between CRDS participants and those in other collaboratives.

**Low-Income Collaborative ("LIAC"):** The Commission recognized that the CRDS and the LIAC are separate but parallel efforts and encouraged parties to share low-income rate design recommendations with the CRDS participants for consideration.[21]

Duke Energy kicked off the LIAC on July 29, 2021. The LIAC has several tasks including 1) assessing affordability challenges, 2) defining affordability, 3) investigating the current state of programs that can help low-income or vulnerable customers, and 4) developing recommendations for both existing and new programs. While developing rate schedules is not a core function for the LIAC, efforts were made to keep this group informed of rate design considerations from the CRDS Residential Working Group that could impact low-income and vulnerable customers. On the other hand, any low-income discounts or programs would be considered in the LIAC rather than the CRDS, as these typically are layered on top of, rather than replace, the base rate schedule. Duke Energy held a joint meeting in January 2022 with the CRDS Residential Working Group, the LIAC and Demand Side management (DSM)/Energy Efficiency (EE) Collaborative to increase awareness across the initiatives and share LMI rate design ideas.

**Electric Transportation Collaborative:** Through the Electric Transportation (ET) Collaborative, Duke Energy engages in a collaborative stakeholder process to provide input and feedback on future EV programs and pilots. The ET Collaborative process was ordered by the NCUC in November 2020,[22] along with the partial approval of Phase I pilot programs designed to help North Carolina increase the number of registered, zero-emission vehicles to 80,000 by 2025 as directed by Governor Roy Cooper's Executive Order 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy. With the support of the ET Collaborative, Phase II pilot programs were filed in May 2021. The Phase II pilot programs will, among other objectives, increase EV charging options along state highways, expand EV options in low- to moderate-income communities, and provide support to school systems to purchase up to 60 electric school buses. The ET collaborative meets quarterly to allow stakeholders to receive updates on Phase I pilots and the status of the Phase II pilot application.

[21] NCUC March 31, 2021 Order, p. 182.

[22] See *Order Approving Electric Transportation Pilot, in Part,* issued November 24, 2020, Docket Nos. E-7, Sub 1195 and E-2, Sub 1197.

# 9 Appendices

## A. CRDS Working Group Timeline

LEGEND
WG 1: GREEN
WG 2: GOLD
WG 3: BLUE
WG 4: GREY

**JUL 2021**

**July 9** – Kickoff Session
**July 14** – Kickoff Session
**July 21** – Kickoff Session
**July 22** – **Subgroup A**: Duke OU Period Proposal and Supporting Analytics
**July 29** – **Subgroup B**: Stakeholder NEM presentations

**AUG 2021**

**August 4** – Kick-off
**August 5** – **Subgroup C**: Duke NEM Mechanics Proposal
**August 11** – Session 1: Load factor-based rates and demand changes
**August 12** – Session 1: TOU rates and NEM discussion
**August 19** – **Subgroup D**: NEM Design Embedded and Marginal Cost

**SEP 2021**

**September 2** – **Subgroup E** (NDA Only): Duke Forecast Data Review
**September 8** – Session 2: Demand charges and demand response
**September 14** – **Subgroup F**: Final Discussion on TOU and NEM Proposals
**September 14** – **Subgroup** A: Non-residential NEM policies
**September 15** – **Subgroup** B: Aggregation of loads / conjunctive billing
**September 15** – Session 1: Existing Duke RTP / HP rates and national case studies
**September 20** – Residential Rate Overview
**September 21** – **Subgroup A**: Duke presentation on marginal cost pricing analysis
**September 27** – Session 1: Existing Rates and TOU Proposal
**September 28** – **Subgroup B** Stakeholder Presentations
**September 29** – Session 2: EV Rates Discussion

**OCT 2021**

**October 12** – **Subgroup C**: Modified Economic Development Rider, Dynamic Pricing for Large Businesses, Expansion of HP Rates
**October 13** – Session 3: Continuation of demand charge design issues and interruptible/curtailable rates
**October 19** – **Subgroup D**: Duke conducted a working session to solicit stakeholder feedback for HP rate solutions and CBL setting process
**October 20** – Session 2: HB 951, Permanent foundation, Schedule RT, Fixed Charges and Analysis
**October 27** – **Subgroup A**: Residential EV Rates

**NOV 2021**

**November 2** – **Subgroup E**: Duke summarized the stakeholder objectives heard to date through the CRR, and presented three rate design concepts: an expanded HP option, a new dynamic pricing rate option and new Economic Development Rider
**November 3** – Session 3: DEP Analytics
**November 4** – **Subgroup B**: Non-Residential EV Rates
**November 10** – **Subgroup C**: Residential EV Rates
**November 17** – **Subgroup D**: Non-Residential EV Rates

**DEC 2021**

**December 1** – **Subgroup C**: Case studies on load aggregation
**December 7** – Session 2: ICF summarized the topics covered over the course of the 8 WG meetings. Duke provided a requested overview of the current price derivation process for HP and RTP rates and how the CBL impacts fixed cost recovery
**December 12** – Session 4: Marginal cost details, minimum bill analysis, declining block rate, seasonal price difference, all electric option, demand charge TOU

**JAN 2022**

**January 11** – **Subgroup D**: Load Factor Rates
**January 27** – **Subgroup E**: Review merit of current rates and customer class appropriateness. DEP marginal cost analysis
**January 28** – **Subgroup E**: Non-Residential EV Rates

**FEB 2022**

**February 15** – **Subgroup F**: Demand charges. TOU rating periods impact

**MAR 2022**

**March 2** – Session 4: Wrap up
**March 11** – Session 5: Wrap up

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## B. CRDS Stakeholders by Working Group

| Organization | WG 1 | WG 2 | WG 3 | WG 4 |
|---|---|---|---|---|
| AARP South Carolina | | | ✓ | |
| Alliance for Transportation Electrification | ✓ | | | |
| Appalachian Voices | ✓ | | ✓ | |
| Archer Daniels Midland (ADM) | | ✓ | | ✓ |
| Bailey & Dixon, LLP (Counsel for CIGFUR) | ✓ | ✓ | ✓ | ✓ |
| Brooks Pierce | | ✓ | | ✓ |
| Calstart | ✓ | | | ✓ |
| Center for Biological Diversity | ✓ | | | |
| ChargePoint | ✓ | | ✓ | ✓ |
| CIGFUR (Representative) | | ✓ | | ✓ |
| City of Winston-Salem | | | | ✓ |
| Clean Air Carolina | ✓ | ✓ | ✓ | ✓ |
| Coastal Conservation League | ✓ | ✓ | ✓ | ✓ |
| Corning | | ✓ | | ✓ |
| Department of the Army, Army Legal Services | | ✓ | ✓ | ✓ |
| Environmental Defense Fund | ✓ | | | ✓ |
| Duke University | | | | ✓ |
| EVgo | ✓ | | | ✓ |
| Facebook | | ✓ | | ✓ |
| FreeWire Tech | ✓ | | | |
| Google | | ✓ | | ✓ |
| Greenlots | ✓ | | | |
| ICF | ✓ | ✓ | ✓ | ✓ |
| Kroger Co. and Harris Teeter | ✓ | ✓ | | ✓ |
| Linde | | ✓ | | |
| Lion Electric | ✓ | | | ✓ |
| Lockhart Power Company | ✓ | ✓ | ✓ | ✓ |
| Messer North America | | ✓ | | ✓ |
| NC Commerce Public Staff Energy Division | ✓ | ✓ | ✓ | ✓ |
| NC Conservation Network | | | ✓ | |
| NC Department of Justice | ✓ | ✓ | ✓ | ✓ |
| NC Electric Cooperatives | ✓ | ✓ | | |
| NC Justice Center | ✓ | | | |
| NC Sustainable Energy Association | ✓ | ✓ | ✓ | ✓ |
| NC Utilities Commission Public Staff | ✓ | ✓ | ✓ | ✓ |
| NC WARN | ✓ | | | |

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| Organization | WG 1 | WG 2 | WG 3 | WG 4 |
|---|---|---|---|---|
| North Carolina Electric Membership Commission (NCEMC) | ✓ | ✓ | ✓ | ✓ |
| North Carolina Department of Transportation | ✓ | | | |
| Nova Energy Consultants (representing CUCA) | | ✓ | | ✓ |
| Parkdale Mills | | ✓ | | ✓ |
| Southern Alliance for Clean Energy (SACE) | ✓ | ✓ | ✓ | ✓ |
| South Carolina Office of Regulatory Staff | ✓ | ✓ | ✓ | ✓ |
| Solar Energy Industries Association (SEIA) | ✓ | | | |
| Sierra Club | ✓ | ✓ | ✓ | |
| Solar United Neighbors | ✓ | | | |
| Southern Environmental Law Center | ✓ | | ✓ | |
| St. Paul's Christian Church | ✓ | | ✓ | ✓ |
| Sunrun | ✓ | | ✓ | |
| United States Department of Defense | | ✓ | | ✓ |
| Utility Management Services Inc. | ✓ | ✓ | | ✓ |
| Vote Solar | ✓ | | ✓ | |



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A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury St.
Dobbs Building
5th Floor
Raleigh, NC 27603

31 March 2022

Dear Chief Clerk Dunston:

In accordance with Orders in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219, Duke Energy (Duke) retained ICF Resources, LLC (ICF) in May 2021 to serve as a third-party independent facilitator for the stakeholder portion of its Comprehensive Rate Design Study (CRDS).

In the above referenced Orders, the Commission stated that it was "persuaded that in depth evaluation, debate, and discussion by and among stakeholders regarding cost to serve, rate design, and making the most efficient use of the electric system is necessary to achieve results that are in the public interest[.]" The Commission further required that "[a]ll parties to the rate case proceeding be afforded the opportunity to participate as stakeholders in the Rate Design Study."

This letter confirms that ICF and Duke coordinated engagement with stakeholders in accordance with the above requirements of the Commission Orders. All parties to the relevant NCUC rate proceedings were given the opportunity to participate in the stakeholder working groups, as were additional groups based on targeted outreach, and those who requested to participate at any point in the process.

Further detail regarding the stakeholder engagement process has been submitted to the Commission in Duke's quarterly status reports.

We firmly believe these stakeholder discussions have thus informed Duke's approach to rate modernization as described in its Rate Design Roadmap. This letter is not an official endorsement by ICF of the Rate Design Roadmap, but rather is meant to certify and underscore the inclusiveness and effectiveness of the CRDS stakeholder process only.

Sincerely,

Maureen Quinlan
Manager, Distributed Grid Strategy
ICF

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ICF

OFFICIAL COPY

Mar 31 2022

**CERTIFICATE OF SERVICE**

I certify that a copy of Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Rate Design Study Roadmap, in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record.

This the 31st day of March, 2022.

Jack E. Jirak
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