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December 4, 2020

Via Electronic Filing

Ms. Kim Campbell
Chief Clerk
North Carolina Utilities Commission
430 North Salisbury Street
Dobbs Building
Raleigh, NC 27603-5918

RE: In the Matter of: Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Docket No. E-2, Sub 1219

Dear Ms. Campbell:

Enclosed for filing in the above captioned docket is a Joint Partial Proposed Order submitted on behalf of our clients, the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy (collectively, Justice Center et al.) along with Intervenors North Carolina Sustainable Energy Association (NCSEA) and Vote Solar relating to misallocation of demand-related costs in the Company's Cost of Service Study, reducing the Basic Customer Charge, the Comprehensive Rate Design Study, and Affordability Stakeholder process.

The issues covered in the attached Partial Proposed Order were left unresolved by the Agreements and Stipulations of Settlement entered into between DEP, Justice Center et al., and NCSEA on July 23, 2020 (as amended on August 10) and between DEP and Vote Solar on July 9, 2020 (as amended on August 5). Intervenors support the sections of the Partial Proposed Order relating to the issues covered in our respective Agreements and Stipulations of Settlement submitted in this docket by DEP.

As set forth in more detail in the attached Joint Partial Proposed Order, Justice Center et al., NCSEA, and Vote Solar respectfully ask the Commission to find that the Company's cost of service study (COSS) misallocates distribution plant costs by (1) inappropriately classifying a portion of distribution plant costs as "customer-related" using the minimum system method, and (2) using a non-coincident peak demand allocator that does not take into account the effects of load diversity on equipment sizing and costs.

Correcting these cost-allocation errors would result in a lower overall allocation to the residential class. Justice Center et al., NCSEA, and Vote Solar ask the Commission to correct for this over allocation by ordering that the residential class base revenues increase on the same percentage basis as the system-average increase otherwise allowed by the Commission, if any.

With regard to rate design, Justice enter et al., joined by NCSEA and Vote Solar, ask the Commission to find that removing the distorting effects of the minimum system method from the Company's COSS also removes any justification for maintaining the basic customer charge (BCC) at $14.00. Using the basic customer method (and removing uncollectible expenses as usage-related) results in a cost-justified average BCC of $9.63 for the residential class. Justice Center et al., NCSEA, and Vote Solar ask that the Commission order the Company to recalculate the BCCs for the residential rate class schedules consistent with the basic customer method, with any difference from the current BCC recovered through the volumetric rate. Finally, the Comprehensive Rate Design study should be tasked with making recommendations for how the embrace of the basic customer method in the Company's COSS should translate to modifications of the BCC for non-residential rate classes.

In addition, Justice Center et al., NCSEA, and Vote Solar include in the attached Joint Partial Proposed Order proposed findings and conclusions in support of a Comprehensive Rate Design study and Affordability Stakeholder Group.

Please do not hesitate to contact undersigned if you have any questions.

Sincerely,

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina.	)	**JOINT PARTIAL PROPOSED ORDER OF NORTH CAROLINA JUSTICE CENTER, NORTH CAROLINA HOUSING COALITION, NATURAL RESOURCES DEFENSE COUNCIL, SOUTHERN ALLIANCE FOR CLEAN ENERGY, NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, and VOTE SOLAR**

BY THE COMMISSION: Based on the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

<u>Cost of Service Allocation Methodology</u>

1. The Commission accepts the results of the Company's cost of service study (COSS) as just and reasonable in light of all the evidence presented with the exception of the misallocation of distribution plant costs. The Company misallocated distribution plant costs in two ways: (1) by inappropriately classifying a portion of such costs as customer-related using the minimum system method and (2) using a non-coincident peak demand allocator.

2. The Company shall use the basic customer method instead of the minimum system method to classify distribution plant costs. The basic customer method reflects those costs that are truly customer-related, in other words, those costs that are driven by the number of customers rather than by usage. The customer-related costs captured by the basic customer method include service drops, customer service and billing costs, and metering. The use of the basic customer method is just and reasonable in light of the evidence presented and more accurately reflects principles of cost-causation. The Commission addresses a further consequence of ordering the use of the basic customer method in the section on Rate Design relating to the Basic Customer Charge below.

3. The Company shall allocate demand-related distribution costs to rate classes on the basis of each class's diversified peak demand, which accounts for the effect of load diversity on equipment sizing and cost. Allocating

demand-related distribution costs on the basis of class diversified peak demand is just and reasonable in light of the evidence presented and more accurately reflects principles of cost-causation.

4. The Company's COSS allocated more distribution plant costs to the residential rate classes than would be just and reasonable considering the evidence presented and cost-causation principles. The residential class base revenues shall increase on a percentage basis by no more than the system-average increase otherwise allowed by this Order.

Rate Design – Residential Basic Customer Charge

5. The Company shall decrease the monthly Basic Customer Charge (BCC) for residential rate class from $14.00 to an average of $9.63, consistent with the adoption of the basic customer method in the Company's COSS and the removal of uncollectible expenses from the BCC. The Company shall recalculate the BCCs for the residential rate class schedules consistent with the basic customer method, with any difference from the current BCC recovered through the volumetric rate. The reduction in the BCC is just and reasonable in light of all of the evidence and consistent with cost-causation principles.

Comprehensive Rate Design Study

6. The Public Staff and Company shall jointly initiate a Comprehensive Rate Design Study (Study), overseen by the Commission, independently facilitated, and with the participation of other interested stakeholders. Any parties to this general rate case will be considered stakeholders for the Study. The Study shall commence within thirty days of entry of this Order, shall be guided by the rate design principles set forth by Public Staff witness Floyd, take into consideration the conclusions and recommendations of the Affordability Stakeholder Group, and shall include quarterly reports to the Commission, and conclude with a report to the Commission no later than one year from the entry of this Order filed in this rate case docket.

Affordability Stakeholder Process

7. Within 30 days of entry of this Order, Commission staff shall initiate and oversee an Affordability Stakeholder Group with the participation of the Company, Public Staff, and organizations representing the interests of customers of the Company who are low-income, on fixed-income, live at or below 150% of the Federal Poverty Line, or who reside in subsidized affordable housing or

public housing, or have knowledge or experience with bill-payment assistance programs or low-income energy efficiency or weatherization programs.

8. The Affordability Stakeholder Group shall review data from the Company relating to affordability, energy burdens, and energy security, including but not limited to disconnections for nonpayment, arrearages, late fees, usage data and energy intensity data by income levels and geography. The Affordability Stakeholder Group shall consider potential affordability rate designs, including a Percentage of Income Payment Plan (PIPP), a flat percentage discount for qualified customers, and a tiered percentage discount that are at a scale commensurate with the need identified.

9. Within 180 days of entry of this Order, the Affordability Stakeholder Group shall generate recommendations for new affordability programs, including affordable rate designs, arrearage management, and energy efficiency for low-income households that are at a scale commensurate with the need identified. The affordable rate designs, arrearage management, and funding mechanisms that the Affordability Stakeholder Group recommends for adoption shall be forwarded for consideration by the Comprehensive Rate Design Study. The Affordability Stakeholder Group shall reconvene annually, review relevant data, and file with the Commission a report on whether the enacted changes have been effective in addressing affordability challenges.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 4

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Minimum System

Company witness Hager provided testimony regarding the Company's COSS, including the use of its version of a minimum system analysis to allocate distribution costs. Justice Center et al. witness Wallach provided testimony regarding the misallocation of distribution costs in the Company's COSS. CIGFUR witness Phillips provided additional testimony relating to the Company's use of the minimum system method. The Company also relied on the Public Staff's Minimum System Report (MSM Report), issued in Docket No. E-100, Sub 162 (Official Exhibits, vol. 11, 1303 (Hager DEP Redirect Ex. 1)).

a. Company’s Classification of a Portion of Distribution Plant Expenses as Customer-Related by Use of Minimum System Method

The following expenses that are classified as customer-related by the Company in its COSS were not disputed by any party: meter reading, billing and collection, and customer information and services (operating expenses in FERC Accounts 901-917); service drop and meter (FERC Accounts 369-370). Tr. vol. 11, 1040. These categories are the costs that are classified as customer-related by the basic customer method for cost-allocation purposes. Tr. vol. 11, 1040; vol. 14, 420.

In addition to those billing, customer service, meter, and service drop costs, however, the Company used a modified version of the so-called minimum system method in its COSS to allocate a portion of distribution plant costs as customer-related. The minimum system method estimates what it might have cost the Company to build a distribution grid with “minimum” sized equipment. Specifically, DEP applies minimum-system to the costs recorded in FERC Accounts 364 (poles, towers, and fixtures), 365 (overhead conductors and devices), 366 (underground conduit), 367 (underground conductors and devices), and 368 (line transformers). Tr. vol. 11, 1040; Tr. vol. 11, 1037-40; Tr. vol. 14, 414, FN 8. Under the basic customer method, costs recorded in FERC Accounts 364 to 368 are classified as demand-related for cost-allocation purposes. Tr. vol. 11, 1040; vol. 14, 420.

As used by the Company, the minimum system calculation is based not on the costs of the minimum-sized distribution equipment that is commercially available, but instead based on the smallest sized equipment currently used on the Company’s grid. Tr. vol. 11, 1223; Tr. vol. 14, 415. The Company’s modified minimum system approach involves a calculation to estimate the cost of such minimum-sized equipment and discounts those costs to simulate the historical embedded costs of the hypothetical minimum system based on the average age of distribution equipment. Official Exhibits, vol. 11, 1262 (Hager DEC Redirect Ex. 1). The Company then allocated those hypothetical minimum distribution grid costs as customer-related and allocated the remaining distribution plant costs as demand-related. Tr. vol. 11, 1223-24.

Witness Hager testified that the Company’s underlying rationale for using this hypothetical construct in the COSS is its belief that each customer “caused” some minimum portion of the distribution grid to be built in order to connect that customer to the grid. Tr. vol. 11, 1039-40. Witness Hager justified the use of the minimum system method based on the Company’s historic use of the methodology in its COSS along with the inclusion of minimum system as one among several recognized methods for allocating the embedded costs of distribution plant in the 1992 NARUC Cost Allocation Manual (NARUC CAM). Tr. vol. 11, 1038. The Company provided no outside support for its belief that a portion of distribution plant should be deemed customer-related other than the inclusion of MSM in the 1992 NARUC CAM and the Public Staff MSM Report.

The only other witness supporting the continued use of MSM was CIGFUR witness Phillips, who likewise relied on the 1992 NARUC manual as the only authority for continued use of the MSM. Tr. Vol. 14, 308. Witness Phillips also asserted that safety and reliability concerns drive certain investments in distribution plant, and thus, those distribution plant costs ought to be considered customer-related. Id. at 306.

The Commission heard evidence that prepublication drafts of the NARUC CAM included the basic customer method in the section on allocating embedded distribution plant costs in COSS. The Washington Utilities and Transportation Commission critiqued the NARUC task force for removing from the final edition of the CAM a discussion of the basic customer method, the method used by rate-regulated utilities in Washington and which was then "the most common approach taken by Commissions around the country." Tr. vol. 14, 452 (citing Official Exhibits, vol. 14, 420 (Ex. JFW-9)). A later NARUC-commissioned report on charging for distribution utility services in the year 2000 noted that about 30 states then used the basic customer approach rather than the minimum system method. Tr. vol. 14, 420-21 (FN 18).[1] Earlier this year, the Regulatory Assistance Project published a comprehensive study of cost-allocation methods, which concluded that the basic customer method is the best practice and included an extensive critique of the minimum system method. Tr. vol. 14, 421; Official Exhibits vol. 11, 971-89 (Public Staff Pirro Hager Cross-Examination Ex. 1).

Witness Wallach testified that he had not completed an exhaustive survey, but was aware of utilities using the basic customer method in Arkansas, California, Colorado, District of Columbia, Illinois, Indiana, Iowa, Maryland, Massachusetts, Michigan, Oregon, South Carolina, Texas, Utah, and Washington. Tr. vol. 14, 420-21.

On rebuttal, DEP witness Hager defended the use of the minimum system method, reiterating the assumption that all customers cause a minimum distribution system of poles, wires, and transformers in order to be connected to

[1] See Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, 30 (December, 2000), available at: https://pubs.naruc.org/pub.cfm?id=536F0210-2354-D714-51CF-037E9E00A724 (RAP Distribution Rate Design Report).

the grid and thus, those costs should be deemed customer-related. As in her direct testimony, witness Hager relied on the inclusion of the minimum system method in the 1992 NARUC CAM as authority. Tr. vol. 11, 1062. Witness Hager testified that she was generally familiar with, but did not address the detailed criticisms of the use of the minimum system method set forth in the RAP Cost Allocation for a New Era Manual. Official Exhibits vol. 11, 971-89 (Public Staff Pirro Hager Cross-Examination Ex. 1). Witness Hager testified that Cost of Service needs to avoid subjective aspects to the extent possible. Tr. vol. 11, 1216.

b. Discrepancy Between Distribution Plant Engineering Practice and Concept of Minimum System Method

The evidence in the record shows that it is the standard engineering practice of electric utilities, including DEP, to design and build distribution plant to meet expected peak demand of customers. Tr. vol. 14, 415-16; vol. 11, 1226. Starting with the assumption that some portion of the shared distribution grid is customer-related, the Company uses the minimum system method to model a hypothetical minimum distribution grid. Tr. vol. 11, 1224. The Company did not, in fact, design and build a "minimum" sized distribution grid to connect customers, and then overlay the remaining distribution grid to meet customer demand. Id. Justice Center et al. witness Wallach quoted from the textbook Electric Power Distribution System Engineering to show that the typical utility practice is to size and invest in distribution plant based on an expectation of customer demand. Tr. vol. 14, 449. Witness Wallach quoted testimony from Indiana Michigan Power Company in the Indiana Utility Regulatory Commission explaining that the minimum system approach of classifying FERC Accounts 364-368 as customer-related "does not recognize the Company's standard engineering practice of planning and sizing distribution facilities to meet the peak demand of the customers served by those facilities." Therefore, the "peak demand" and not number of customers is what causes Indiana Michigan Power Company to incur distribution plant costs. Id. at 416.

As explained by witness Wallach:

> Contrary to typical engineering and investment practice, the Company's minimum-system analysis posits an imaginary world where some portion of the Company's distribution-grid costs were incurred regardless of customer demand. In this fictional world of the minimum system analysis, spending on the imagined minimum grid is considered to be driven by

> number of customers and thus classified as customer-related. But in the real world, spending on the actual distribution grid is driven by customer demand and thus appropriately classified as demand-related.

Id. at 416-17. Witness Hager agreed that when the Company's engineers build the distribution grid, they size distribution plant to serve actual and expected load. Tr. vol. 11, 1226. Duke Energy also referred to its distribution system design practice in its written report to the Public Staff when it was preparing its MSM Report. Official Exhibits, vol. 11, 1269 & 1273 (DEC Hager Redirect Ex. 1) ("Each component of the distribution system must be designed to meet the maximum anticipated demand of the components 'downstream" from it'"); see also Tr. vol. 16, 199 (DEP witness Oliver noting that spending on distribution plant over the last five years "was largely driven by customer load growth").

In defending the Company's treatment of a portion of the distribution plant as "customer-related," witness Hager testified in rebuttal that the numbers of poles, conductors, and transformers are "directly related to the number of customers on the utility's system." Tr. vol. 11, 1062 (quoting NARUC CAM at 90). Witness Hager also agreed that a characteristic of the distribution grid is that it is shared between customers. Tr. vol. 11, 1226. As a result, there is often no additional cost to distribution plant for adding an additional customer (as is the case where a new home can connect to the grid in an existing neighborhood with only a service drop) and no additional savings from removing a customer (as is the case when an existing home in the middle of a neighborhood is torn down and removed from utility service). Id.

The Company assumes that its modified minimum system method provides a calculation that is an adequate approximation of the distribution plant that would have been necessary for each customer to power a single light bulb at the same time. Tr. vol. 11, 1039. The Company did not present evidence to support this assumption. The Company accepted that, since 1992 when the NARUC CAM was published, dramatic efficiency gains have been made in lighting. As a result, it takes roughly 10% of the energy to provide the same amount of lighting as was the case thirty years ago. The Company made no adjustments in its calculation of what it considers to be the resulting minimum-sized distribution grid for each customer to power a single light bulb. Tr. vol. 11, 1229.

c. Practical Difficulties with Application of Minimum System, Including Potential Double-Allocation of Demand Costs

The Commission also received evidence of practical difficulties with the application of the minimum system method. Tr. vol. 14, 417. First, the Commission heard evidence that there is subjectivity and significant variation in the application of the minimum system methodology. As shown in the Public Staff MSM Report, DEC, DEP, and Dominion Energy North Carolina all apply the minimum system method in different ways that yield different results. Official Exhibits, vol. 11, 1261-64 (Hager DEC Redirect Ex. 1). This variability in the calculation of what constitutes a "minimum system" has been present for decades, as documented in a 1981 article in Public Utilities Fortnightly. Official Exhibits, vol. 14, 400 (Ex. JFW-2) ("The [minimum system] concept is very difficult to define and consequently susceptible to widely varying interpretations. No single method exists for calculating the cost of this system").[2]

The Commission received evidence that a truly minimum system would not consist of the same amount of equipment (for example, the same number of transformers or poles) as the actual system built to serve load. Tr. vol. 14, 417; see also Official Exhibits vol. 11, 1117 (Public Staff Pirro Hager Cross-Examination Ex. 1) ("load levels help determine the number of units as well as their size"). In its modified minimum system analysis, the Company assumes the same number of poles and transformers for its hypothetical minimum grid as were installed to meet real-world demand. Tr. vol. 14, 436. The Company also uses the smallest sized-equipment now in use in its analysis, not the smallest available equipment. As loads on the Company's distribution grid grow, the minimum size of installed equipment grows, resulting in inflation of hypothetical minimum system costs. Official Exhibits vol. 11, 1117 (Public Staff Pirro Hager Cross-Examination Ex. 1); Tr. vol. 11, 1231.

The Commission received evidence that the Company's modified minimum system analysis does not account for the load-carrying capability of the hypothetical minimum-size grid. Tr. vol. 14, 417-18. The allocation of distribution costs is distorted as a result because the load-carrying portion of hypothetical minimum grid costs are allocated on the basis of customer number. Id. The remaining portion of distribution plant costs are allocated on the basis of each class's total demand, even though some of that demand would have been carried by the minimum-size portion of the distribution grid. Id.

[2] George J. Sterzinger, The Customer Charge and Problems of Double Allocation of Costs, PUBLIC UTILITIES FORTNIGHTLY 30–32 (1981).

The Company did not calculate what actual load the Company's hypothetical minimum system would carry to each customer. Tr. vol. 11, 1229. The Company offered no evidence to rebut the criticisms raised by Justice Center et al. that the minimum system can result in double counting demand-related costs for those customers whose demand would be met by the minimum system alone. Tr. vol. 14, 418-20.

Witness Wallach offered a concrete example of how the use of the minimum system method can result in a double allocation of demand related costs. Tr. vol. 14, 418-20. In the first example, a nineteen-unit apartment building with a combined load of 30 kW and a commercial facility with a load of 100 kW share a single feeder. In this instance, the "minimum-size feeder" is large enough to cover the combined load on the system, such that the minimum cost is equal to the total actual cost of the feeder. Under the minimum system method, the entire cost of the feeder is classified as customer-related and the residential class (with 19 of the 20 customer accounts served on this system) is allocated 95% of the costs, even though those 19 residential customers are responsible for less than 25% of the load. In the second example, with the same number of customers, the commercial facility has a load of 270 kW, requiring a larger feeder. As in the prior example, the residential class would be allocated 95% of the minimum cost of the feeder as customer-related (even though that minimum cost still covers their entire demand), and would also be allocated an additional 10% of the demand-related feeder costs—those costs in excess of the minimum-size feeder—even though those costs would not have been incurred without the additional commercial load on the system and the minimum size costs allocated as customer-related to those apartment dwellers already covered their entire demand.

The minimum system method's double allocation problem has been recognized since at least 1981. Official Exhibits, vol. 14, Part 1, 401 (Ex. JFW-2) ("[b]y splitting the distribution system into two parts [one minimum size and the other the remainder], low-use residential consumers are charged twice: once, on a customer basis…and again on a demand basis for a portion of the system sized to serve demand beyond what would be needed to serve them"). Sterzinger provided an example of a hypothetical minimum-sized distribution system that would serve the complete demands of a low-usage customer that is worth quoting in full (assuming a customer charge that has been set based on a minimum system analysis in the COSS):

> If, for example, the minimum overhead lines, conductors, and poles could supply a demand of two kilowatts per residential customer, that amount of

> usage would be paid for in the customer charge. In the determination of demand allocation factors, however, each residential customer's demand is calculated and added to determine the portion of the above minimum system costs to be allocated to the residential class and to each customer through the appropriate rates. So a residential customer who has a demand of two kilowatts will have paid for all the distribution costs associated with his load through the customer charge, but will also have his two-kilowatt usage go into the demand allocation factor to allocate distribution costs associated with above minimum usage.

Id.

In addition to the examples provided by witness Wallach and from the Sterzinger article in Public Utilities Fortnightly, witness Hager was confronted with another hypothetical on cross-examination. Asked to consider a new residential subdivision with a mixture of larger detached homes on large lots, mid-sized connected town homes, and efficiency apartments, witness Hager acknowledged that more poles, conductor, and larger transformers would likely be necessary to serve the expected peak demands of the detached homes when compared to the apartments or town homes. Tr. vol. 11, 1227. Under the minimum system approach, all those differently situated residential customers are allocated the same amounts for a significant portion of the shared distribution grid that was designed and built to serve different loads. Tr. vol. 11, 1228.

In response to these hypotheticals, witness Hager testified that allocating costs in large buckets to large groups of customers inevitably leads to some individual customers paying more than their fair share, but such results do not render the methodology unfair. Tr. vol. 11, 1061 (FN 14); vol. 11, 1228.

d. Public Staff MSM Report Rests on Unsupported Assumptions

The Company also referred to the Public Staff's MSM Report as support for continued use of the minimum system in its COSS. Tr. vol. 11, 1041-42. In its MSM Report, the Public Staff indicated that continued use of the minimum system in the COSS is reasonable based on its belief that there is a minimum portion of the cost for the distribution grid that is incurred regardless of demand. Official Exhibits, vol. 11, 1257 (Hager DEC Redirect Ex. 1). The Public Staff did not offer any support for its assertion "that distribution related costs must be sized to meet some level of maximum demand" while at the same time "there is also a minimum cost for the distribution system that must be incurred regardless of demand." Id.

Witness Wallach observed that the Public Staff MSM Report offered no specific guidance or recommendations regarding the appropriate approach for classifying distribution costs in a COSS. Instead, the Public Staff states that it "believes" generally that it is reasonable to use the results of a minimum-system. The Public Staff assumes that there is a minimum portion of distribution grid costs that are incurred regardless of demand and should thus be deemed "fixed." Witness Wallach testified that the Public Staff did not support this assumption in its MSM Report, which ignores the actual utility practice of building the grid to serve load. Tr. vol. 14, 555-56. Public Staff witness Floyd acknowledged that the perspective of which costs are fixed and which are variable can depend on the time horizon being considered, among other factors. Tr. vol. 10, 115-16.

Witness McLawhorn testified that the Public Staff did not say in its MSM Report that the minimum system is "the ideal method, or the best method, or the greatest method." Tr. vol. 15, 1047. Public Staff witness Floyd testified that "the Public Staff continues to believe that there is a demand-related portion to that [distribution costs] and a customer-related portion to that." Tr. vol. 15, 1042 (emphasis added). But the Public Staff, much like the Company, has not offered evidentiary support for that belief.

In its MSM Report, the Public Staff relied to a large extent on the 1992 NARUC Cost Allocation Manual in support of its conclusion that it would be reasonable to continue using the MSM to establish the maximum amount of customer-related costs that could inform the Company's design of the Basic Customer Charge. Public Staff witnesses Floyd and McLawhorn testified that since it issued its MSM Report in 2019, the Regulatory Assistance Project's Cost Allocation Manual was issued, the first comprehensive analysis of cost allocation for electric utilities in decades. Tr. vol. 15, 1040-43. The Public Staff also indicated that it would be willing to change its opinion about the continued reasonableness of using the minimum system method. Tr. vol. 15, 1049, 109-91; Official Exhibits, vol. 11, 1266 (Hager DEC Redirect Ex. 1, p. 16, FN 25).

e. GIP Investments in Distribution Plant will Inflate Costs Allocated Via Minimum System Method

Witness Hager testified that the Company would continue to use the minimum system method to allocate distribution costs even after GIP investments were made to distribution plant. Tr. vol. 11, 1067. Witness Huber testified that the Company would classify GIP costs based on their FERC account and that the Company would use the minimum system method to allocate distribution costs. Tr. vol. 11, 1261.

Witness Hager testified that the Company would oppose considering benefits of GIP investments when allocating costs for those programs. Tr. vol. 11, 1067-68, 1206-07. During cross examination, witness Hager testified that it would be fair to allocate all of the costs of a hypothetical GIP program to one class of customers (based on minimum system and other cost of service principles currently used by the Company) even in the event that the Company's evidence demonstrated that the class would receive zero benefits from that investment, while another class that was allocated zero costs from that investment received all of the benefits. Tr. vol. 11, 1284-85.

Witness Phillips testified that application of minimum system to distribution GIP costs is appropriate because such costs are typical and that any improvements to the grid are to "the same distribution system." Tr. vol. 14, 349.

Witness Wallach testified that it would be inappropriate to apply a minimum system analysis to GIP costs because those investments are not intended to connect customers to the grid. Tr. vol. 14, 450. As described by Company witness Oliver, the purpose of the GIP is to more reliably, intelligently, and economically serve load, including more effectively integrate distributed renewable resources. Tr. vol. 16, 110-11; Tr. vol. 4, 124-25, 140; see also Tr. vol. 13, 160 (Duke witness Smith testifying that GIP expenditures meet deferral test in part because they are "major non-routine investments, that produce substantial customer benefits").

f. Use of Minimum System Method Is Not Required for Company to Recover Its Costs

Witness Hager testified that the Company is fundamentally agnostic on the issue of how costs are allocated as long as those allocations are based on sound principles of cost causation and the Company can fairly recover its costs. Tr. vol. 11, 1299-1300. The Public Staff noted in its MSM Report that as cost of service is translated to rate design, the goal "is to ensure that the utility has a reasonable ability to recover its costs, provide a fair return to its shareholders, attract capital for future investment, and encourage efficient energy use." Official Exhibits, vol. 11, 1257 (Hager DEC Redirect Ex. 1). Duke Energy affiliates have experience using the basic customer method from its South Carolina and Indiana utilities for many years. Tr. vol. 14, 421. The Company did not put forward any evidence that adoption of the basic customer method in place of the minimum system method would interfere with its ability to recover its costs.

Discussion and Conclusions on Minimum System Method in the COSS

Upon consideration of all the evidence in this docket, the Commission disapproves of DEP's use of the minimum system method for cost allocation (and by extension, for rate design, as set forth later in this Order) and orders the use of the basic customer method in its place. The Commission places significant weight on the testimony of Justice Center et al. witness Wallach concerning the conceptual flaws inherent in the minimum system method, which allocates costs based on a hypothetical grid that was not built by the utility and thus, is not used and useful in the provision of service. In this regard, the minimum system construct runs counter to fundamental principles cost causation. The Company's COSS should be based whenever possible on actual costs incurred for plant that is used and useful, not costs for a hypothetical minimum distribution grid that was not built and would be of dubious value. The best evidence in the record supports the conclusion that the Company designs and builds distribution plant to meet a maximum level of demand and incurs no separate or distinct costs for supplying a minimal level of demand.

In addition, the Commission finds and concludes that the minimum system method is subject to flaws in implementation. There is simply too much subjectivity involved in the designation of what counts as "minimum" size equipment and the amount of equipment that would be needed for each customer to power a light bulb. The Commission finds that an advantage of the basic customer method is that it removes this subjectivity and unreasonable variation between utilities that follow from disparate application of the minimum system method. In this regard, the Commission agrees with DEP witness Hager that the Company's COSS needs to avoid subjective aspects as much as possible, and concludes that adopting the basic customer method goes a long way to removing subjectivity from the COSS.

The Commission finds persuasive the reasons given by regulatory commissions in Illinois and Florida for rejecting the use of the minimum system method in a utility's COSS. As noted in a 2008 rate case order by the Illinois Commerce Commission, "attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic. We reject the use of the [minimum distribution system] in this proceeding…." The Illinois Commission rooted its decision in its conclusion that "distribution systems are designed primarily to serve electric demand." *In Re Commonwealth Edison Co.*, 268 P.U.R.4th 1 (Ill. C.C. Sept. 10, 2008), aff'd in part, rev'd in part on other grounds, *Commonwealth Edison Co. v. Illinois Commerce Comm'n*, 937 N.E.2d 685 (Ill. App. 2010). Notably, the utility in this case argued against the imposition of a minimum system analysis and pointed out that large commercial customers argue for it because it allocates more costs to residential customers:

> the nonresidential customers that support the MDS [minimum distribution system] concept do so for one obvious reason: the MDS concept would shift costs away from nonresidential customers and on to residential customers. This shift occurs because, under the MDS approach, the basis for allocation of costs is the number of customers rather than customer demand. Because residential customers are far more numerous and use relatively less power than non-residential customers, the effect of the MDS is to shift substantial costs from the non-residential customers to the residential customers.

Id.

In rejecting the adoption of a minimum distribution system analysis, the Florida Public Service Commission concluded: “the simpler, more straight forward approach of allocating only service drops and meters on a customer basis adequately captures the distribution investment that is solely required to extend service to a new customer. This methodology is clear, generally accepted, and requires no series of hypothetical cost and system design calculations that do not reflect how the actual system is designed.” *In Re Gulf Power Co.*, 218 P.U.R.4th 205 (Fla. P.S.C. June 10, 2002). The Florida Commission also noted the logical inconsistency of conducting a minimum system analysis on the distribution system but not the transmission system, and artificial distinction given that “ignores the way the electric system works.” Id.

The Commission finds that the problem with the application of minimum system is not, as suggested by Company witness Hager, that it is sometimes advantages one group of customers and sometimes disadvantages another group of similarly situated customers. Rather, the application of the minimum system method is always unfair in one direction; customers with below-average usage—those customers who place less demand on distribution plant—are allocated more than their fair share of distribution related costs in comparison to above-average usage customers—those customers who in fact cause more distribution costs, which is contrary to cost-causation principles. This theoretical concern is made real by the Company's translation of the minimum system method to rate design in the form of an inflated Basic Customer charge.

The Commission is not persuaded that the inclusion of minimum system as an available method in the 1992 NARUC CAM is a sufficient basis for continued use of the minimum system method in the Company's COSS. Considering all of the evidence in the record, the Commission gives weight to the testimony of witness Wallach and the criticisms of the application of the minimum system method set forth in the RAP Cost Allocation for a New Era manual released earlier this year. The Commission finds and concludes that the Company has not put forward evidence that rebuts the unfairness inherent in the application of the minimum system method to rate design for low-usage customers and the potential to double allocate distribution plant costs to low-usage customers.

The Commission finds and concludes that including consideration of safety parameters in the design of distribution plant does not support treating a portion of those costs as "customer-related," as set forth by CIGFUR witness Phillips. Witness Phillips does not explain why safety considerations in the design or operation of distribution grid assets would justify considering those grid assets as customer-related rather than demand-related. Certain safety compliance costs are imposed on the utility in the construction and operation of utility plant generally, including the Company's generating fleet. But it does not follow that such costs related to safety compliance measures at something like a combined cycle plant should be calculated separately and transformed into customer-related costs.

The Commission is mindful that in the past it has approved of the use of the minimum system method for cost allocation. But tradition and custom are insufficient grounds for its continued use given our findings that it is unreasonable, inherently subjective, and contrary to cost-causation principles. The Commission has considered and carefully weighed the testimony of Company witness Hager and CIGFUR witness Phillips, as well as the Public Staff's MSM Report, and are unpersuaded that continued use of the minimum system method in the Company's COSS serves any useful purpose.

The Commission's concerns with continued use of the minimum system method are amplified by the Company's Grid Improvement Plan. The Commission finds and concludes that the Company's ongoing and planned GIP expenses provide a compelling reason to break with the past reliance on the minimum system method in the Company's COSS. The Company's plan to continue using the minimum system method when calculating a supposed customer-related portion of distribution plant investments that are expected to increase dramatically as a result of GIP investments will have a severe and detrimental effect on the residential rate class. The Commission finds and concludes that applying the minimum system method to the enhanced functionality of the distribution grid following GIP investments is inconsistent with the underlying premise of the minimum system. In other words, a truly “minimum” distribution grid that is conceptualized to merely connect each customer with power for a single light bulb would not need the enhanced functionality contemplated by the GIP.

The Commission concludes that witness Phillips’s testimony to the effect that GIP spending on distribution plant should be considered regular costs runs counter to the partial settlement and stipulation of CIGFUR and several other parties in support of deferral of GIP costs. A criterion for deferral accounting treatment is that the costs in question are new, novel, or extraordinary, in both type of expenditure and in magnitude. In other words, GIP spending on distribution plant cannot at once satisfy the Commission’s criteria for deferral accounting treatment and at the same time be considered ordinary expenses, comparable to distribution grid maintenance. Given the Commission’s approval of the Partial Stipulation and Settlements of CIGFUR, the Public Staff, and several other parties relating to deferral treatment of those GIP components listed in the Second Stipulation and Settlement with Public Staff, the Commission rejects the component of the CIGFUR settlement calling for the Company to apply minimum system method to distribution plant components of GIP.

The Commission gives great weight to the Company’s position that it is fundamentally agnostic on the issue of how costs are allocated as long as those allocations are based on sound principles of cost causation and it can fairly recover its costs. Given the evidence in this record of the pervasive use of the basic customer method by electric utilities around the country, the Commission concludes that the Company will be able to recover its properly allocated distribution plant costs without use of the minimum system method.

As discussed in more detail in the section of this Order concerning the Comprehensive Rate Design Study, the Commission is particularly mindful of the interplay between cost of service methodologies and rate design and the importance of providing guidance and parameters to the Comprehensive Study. The Commission finds and concludes that the Comprehensive Rate Design Study should be informed by the basic customer method for allocating distribution plant costs rather than the minimum system method.

The Commission finds that the Company's use of the basic customer method for allocation of distribution plant is just and reasonable to all parties in light of all of the evidence presented and finds that the Company should not revert to a minimum system method in its COSS without making an affirmative showing that changed circumstances warrant a reevaluation of the Commission's decision.

Class Diversified Peak Allocation for Distribution Plant

Company witness Hager provided testimony regarding the Company's COSS, including the allocation of distribution plant. Justice Center et al. witness Wallach provided testimony regarding the misallocation of distribution costs in the Company's COSS. No other party addressed the issue of class diversified peak.

Witness Hager testified that, for those portions of distribution plant that are demand related (in other words, those portions of distribution plant that were deemed customer-related under the minimum system method), the Company allocated based on Non-Coincident Peak Demand (NCP). Tr. vol. 11, 1036-40. The Company developed the NCP allocators by taking the ratio of the non-simultaneous peak demands of the customers in each class whenever that peak occurred during the test period and comparing that to the sum of customers' non-simultaneous peak demand. Id. at 1036. DEP justified using the NCP allocators because the distribution system serving each neighborhood or other distinct, geographic area must be able to meet the peak demand when it occurs in that area.

Justice Center et al. witness Wallach testified that the NCP allocators fail to account for the effect of load diversity on distribution equipment loading. As a result, the NCP allocators do not reasonably reflect the drivers of the Company's distribution plant costs. Tr. vol. 14, 423. The NCP allocator does not account for distribution equipment serving many small residential customers being smaller (and less expensive) than equipment that serves fewer large industrial customers, even when the sum of the residential maximum demands is equal to the sum of industrial maximum demands. Id. at 426-27. Load diversity takes into account the fact that customers reach their individual maximum demands on different days and different hours. As a result of this load diversity, a group of residential customers served by the same shared distribution equipment will have a lower group peak demand than the sum of those customers' individual maximum demands, as would be assumed by the NCP allocator. Id. A consequence of DEP's approach is a likely overstatement of the residential class's contribution to distribution costs, resulting in an over-allocation to residential customers. Id. at 426-28. The Company did not modify its COSS to allocate demand-related distribution plant costs based on diversified peak as requested in a data request by Justice Center et al. Tr. vol. 14, 427.

Witness Wallach's conclusion was supported by the Company's practice of sizing distribution plant to meet the diversified peak demand of the group served by that equipment, not to meet the sum of the maximum demands of the individual customers in that group. Tr. vol. 14, 424. In response to a data request from the Public Staff in connection with its report on minimum system, the Company stated that it takes into account load diversity when it sizes shared distribution equipment to meet the non-coincident peak. Id. at 425. In addition, witness Wallach provided an example from Duke Energy of how it sizes transformers based on an estimate of the diversified peak load of the customers sharing the transformer in the Carolinas. Id. at 425-26. Witness Wallach testified that load diversity increases with the number of customers taking service from that shared transformer. As the diversity of maximum hourly demands increases, so too does the variance between the sum of those individual customers' maximum hourly demands (the NCP) and maximum demand for the group as a whole (group diversified demand). Id. at 426-27. By not taking this phenomenon into account, the NCP allocator allocates costs to classes as if the sizing and costs of that equipment was driven by NCP rather than diversified demand. Id.at 427.

Company witness Hager did not offer any rebuttal on the issue of using diversified peak demand allocator rather than a NCP allocator for demand-related distribution plant.

Conclusion

Based on the entire record in this proceeding, the Commission concludes that DEP shall no longer rely on the NCP allocator for demand-related distribution plant and shall instead allocate demand-related distribution plant on the basis of each class's diversified peak demand. The Commission finds and concludes that use of the NCP allocator in the Company's COSS is not just and reasonable and does not follow cost-causation principles. The Commission gives significant weight to the testimony of Justice Center et al. witness Wallach, which was supported with examples from the Company regarding how it takes into account load diversity when sizing shared distribution plant equipment. The Commission further gives substantial weight to the Company's decision to not offer any rebuttal on this issue.

The Company should allocate demand-related distribution plant costs based on diversified peak in its COSS in its next general rate case. To account for the likely over-allocation to the residential class by its use of the NCP allocator in this case, the residential class base revenues shall increase on a percentage basis by no more than the system-average increase otherwise allowed by this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 5

The evidence supporting this finding of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Company witness Pirro provided testimony regarding the translation of the Company's COSS to rate design, including the effects of using the minimum system method to inform the proposed and theoretical Basic Customer Charge (BCC). Public Staff witness Floyd testified regarding rate design principles for the BCC. Justice Center et al. witness Wallach provided testimony regarding the BCC calculated under the basic customer method and the effects of an inflated BCC on electricity usage. Justice Center et al. witness Howat provided testimony regarding the effects of an inflated BCC on low-income customers, who tend to be low-usage customers.

The Company requested no change to the BCC. Tr. vol. 11, 1086. Evidence presented at the hearing demonstrated that the current residential BCC is higher than is cost-justified once the minimum system method is removed from the Company's COSS, which informed the Company's rate design. Tr. vol. 12, 19-23. The Company's proposal to increase the residential BCC from $11.13 to $19.50 in the last DEP rate case was the direct result of the application of the minimum system method to the Company's proposed rate design. The Company's proposal in that case would have been 50% of the difference between the then current BCC and the theoretical BCC of $27.82 that included all the distribution plant costs that were deemed "customer-related" by use of the minimum system in the COSS. Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, Docket No. E-2, Sub 1142, pp. 105-06, 108 (Feb. 23, 2018). The Commission ultimately accepted a $14.00 per month BCC as agreed to by DEP and the Public Staff in their partial stipulation and settlement, but the only basis provided in support of an increase in the BCC was based on the application of the results of the minimum system method to inform the Company's rate design.

Evidence from the Company shows that continued reliance on the minimum system method in the COSS for rate design will continue to put upward pressure on the Company's theoretical BCC. DEP witness Pirro testified that if the Company translated the results of the minimum system method to rate design, the residential BCC for rate schedule RS would be $31.75 per month, almost triple the amount calculated by relying on the basic customer method. Tr. vol. 12, 21-23; Official Exhibits vol. 12, 15-16 (Justice Center et al. Pirro/Hager Cross Ex. 2); Official Exhibits, vol. 12, 169 (Pirro Ex. 7). Without accounting for uncollectibles, use of the basic customer method instead of minimum system in the Company's unit cost study results in a BCC of $10.23 per month for residential customers. Tr. vol. 12, 23; Official Exhibits, vol. 12, 15-16 (Justice Center et al. Pirro/Hager Cross Ex. 2). Witness Pirro testified that the Company supports setting the BCC to recover approximately half of the "difference between the current rate and the full customer-related unit cost incurred to serve these customer groups," as it did in the last rate case. Tr. vol. 11, 1089.

Witness Floyd, referring to the Public Staff's MSM Report, testified that the Public Staff's preferred approach for setting the BCC is to use the minimum system method to set a "maximum" allowable amount and the basic customer method to set a minimum amount and then pick an amount in between those two. Tr. vol. 15, 1045-56; Official Exhibits, vol. 11, 1266-67 (DEC Hager Redirect Ex. 1). Witness Floyd testified that the Public Staff generally believes that the utility's "fixed" costs should be recovered with fixed customer charges. Tr. vol. 10, 85, 88-89; vol. 15, 988.

Witness Wallach testified that the Public Staff's assumption that "fixed" costs should be recovered with fixed charges is unsupported by generally accepted principles of cost causation. Instead, fixed charges such as the BCC should be designed to recover only those costs that do not vary with customer usage over the long run. Witness Wallach testified that sunk costs that vary with usage or demand over time but appear fixed only from a short-run accounting perspective should not be treated as "fixed" for purposes of rate design. Tr. vol. 14, 434-35.

Witness Wallach provided testimony regarding the inappropriate recovery of demand-related costs in the BCC as a result of the Company's reliance on the minimum system method in its COSS. Tr. vol. 14, 435-36. Under the basic customer method and after removing uncollectible amounts from the BCC, the average cost-based BCC for the residential class would be $9.63. Id. at 437-38. Witness Wallach testified that the difference between the current BCC of $14.00 and the cost-justified $9.63 should be recovered through the volumetric rate. Without this correction, witness Wallach testified that low-usage customers will subsidize higher-usage customers. Removing the demand-related component from the BCC results in below-average usage and higher-than-average usage customers paying proportional amounts, consistent with principles of cost-causation. Id. at 439. Witness Wallach testified that removing the demand-related portion of the current BCC does not completely eliminate the potential of low-usage customers to subsidize high-usage customers. For example, residents of apartment buildings contribute through the BCC the same amount as residents of detached homes for service drops, even though the cost per customer of a service drop would typically be lower for apartment dwellers than customers living in a single family home. Id. at 440.

Witness Wallach provided testimony showing that the basic customer method, when translated to rate design, results in costs to ratepayers that are proportional to usage (in other words, in proportion to demands placed on the distribution grid and thus, following cost-causation principles). For example, removing the usage-related portion of the current $14.00 residential BCC (that portion that is based on application of the minimum system method) and recovering those dollars instead through the volumetric rate, a customer with below-average usage of 500 kWh per month would contribute $27 per year towards those shared distribution costs, whereas a customer with above-average usage of 1,800 kWh per month would contribute $82 per year, in proportion to usage and consistent with principles of cost-causation. Tr. vol. 14, 440.

Witness Wallach also provided testimony on the price elasticity of electricity, in other words, the changes in consumption patterns that result from a change in the volumetric rate. After surveying the available literature, witness Wallach determined that -0.3 would be a reasonable estimate of the price elasticity (in other words, consumption would be reduced on average by 0.30% for every 1% increase in the volumetric rate). Tr. vol. 14, 443-45. If the BCC continued at $14.00, the volumetric rate would be about 3% less than it would be if the BCC was set at $9.63. Given a price elasticity of -0.3, a 3% reduction in the volumetric rate would result in an overall increase in electricity consumption of about 0.9% for residential customers. Id. Such an increase would undermine progress on ratepayer funded energy efficiency programs and, according to witness Wallach, potentially undo three years of energy efficiency savings. Id. at 445-46. Company witness Pirro testified on rebuttal that failing to recover what the Company classifies as customer-related costs (as calculated using the minimum system method) from the BCC sends the wrong price signal. Tr. vol. 11, 1123.

Witness Howat provided testimony on the effects of a BCC that is higher than cost-justified by including usage-based costs that should instead be recovered in the volumetric charge. Tr. vol. 14, 394-400. According to data from the Energy Information Administration's Residential Energy Consumption Survey, households in the Carolinas headed by low-income residents, African Americans, and senior citizens, on average, use less electricity than their counterparts. Id. at 395-96. This data is consistent with patterns seen across the country and region. Id. at 395-98. Inappropriately high fixed customer charges disproportionately harm these households. Public Staff witness Floyd testified that the residential bill frequency data furnished by the Company is not correlated with customer income levels and as a result, the Public Staff and Company offered no evidence regarding average usage levels of customers by income. Tr. vol. 10, 92-96. Witness Howat testified that an inappropriately high BCC sends a price signal that discourages all households from participating in bill-saving energy efficiency measures, which can be particularly important for low-income households. Tr. vol. 14, 400.

Discussion and Conclusions

The Commission concludes that using the basic customer method to allocate distribution plant and removing uncollectible expenses as costs that vary with usage and thus, more appropriately recovered in the volumetric rate, the average cost-justified BCC for the residential rate class is $9.63. The difference between the cost-justified BCC of $9.63 and the current BCC of $14.00 reflect usage-driven costs that the Company shall collect through an increased volumetric rate.

Two of the three principles that Public Staff witness Floyd testified should inform the comprehensive rate design study are particularly relevant to the issue of setting an accurate BCC: "(1) the ability to connect to the utility system for no more than the cost of connecting to the grid; (2) pay for utility service in proportion to how much they use the system." Tr. vol. 15, 969. The Commission finds that using the results of the basic customer method to set the BCC fulfill these rate design principles because the resulting amount reflects the actual costs to connect to the grid and the resulting volumetric rates reflect the customer's demands on the system in a proportional manner. As noted in a Regulatory Assistance Project report on residential customer charges introduced by witness Floyd:

> The primary purpose of utility regulation is to enforce the pricing discipline on monopolies that competitive markets impose on most firms. Competitive firms nearly always recover all of their costs in the price per unit of their products. Therefore, any fixed monthly

> charge for electricity service represents a deviation from this underlying principle of utility regulation. The most commonly applied customer charges recover only customer-specific costs, such as billing and collection, in a fixed customer charge, leaving all costs of the shared system to be recovered in usage charges.

Tr. vol. 15, 985; Official Exhibits vol. 15, Part 2, 568 (Floyd Ex. 4, RAP: *Electric Utility Residential Customer Charges and Minimum Bills* at 4).[3] In other words, the most common approach is that supported by the basic customer method, which allocates costs of shared distribution plant as demand related and recovered in volumetric rates.

Under the Public Utilities Act, the Commission is required to fix rates in a way that results in the least-cost mix of generation and demand-reduction that is achievable; avoid wasteful, uneconomic and inefficient uses of energy; and promote renewables and energy efficiency. N.C. Gen. Stat. § 62-2(a). Setting the residential BCC based even in part on the minimum system method unreasonably increases the monthly fixed charge, which shifts the Company's cost-recovery away from volumetric rates and discourages investments in energy efficiency and conservation measures. The Commission gives weight to the testimony of witness Wallach on price elasticity and is concerned about the consequences of minimum system method influencing present and future rate design of the Company, which would have the potential to reduce the value of the Company's ratepayer funded energy efficiency programs.

Consistent with the basic customer method and removal of uncollectible expenses from the BCC, the Company shall calculate cost-justified BCCs for the rate schedules in the residential class and include the difference between the prior BCC and the BCC calculated pursuant to the basic customer method in the volumetric energy rate for each residential rate class. As discussed in the comprehensive rate design study section of this Order, the Companies are to work with stakeholders and the Public Staff on appropriate, cost-based BCCs for the remaining rate class schedules without the use of the minimum system method.

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[3] See also RAP Distribution Rate Design Report at 30 ("firms in competitive markets do not – indeed, cannot – price their products according to such methods: they recover their costs through the sale of goods and services, not merely by charging for the ability to consume, or access").

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact and conclusions is contained in the Second Agreement and Stipulation of Partial Settlement between the Company and Public Staff, Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summary of Testimony on Comprehensive Rate Design Study

Public Staff witness Jack L. Floyd testified regarding the Public Staff's recommendation that the Company conduct a comprehensive rate design study prior to filing its next general rate case.

According to witness Floyd, numerous trends in the utility industry justify the need for a comprehensive rate design study; for example, net metering, distributed generation resources, microgrids, energy storage and electric vehicles. Tr. vol. 15, 969. Other considerations that would justify a rate design study include the need for revenue stability; grid improvement costs, coal ash cleanup costs and the transition to a more carbon-free generation portfolio; the need to encourage the efficient use of the electric system and promote energy efficiency; customer desire for more information and the dynamic ability to receive and respond to that information. Tr. vol. 15, 971. Finally, the rate design structures of DEC and DEP remain very different eight years after the merger of Duke Energy and Progress Energy, and a study could assist in a transition to consolidation of the rate designs of the two utilities. Tr. vol. 15, 972.

In light of these issues facing the utility of the future, witness Floyd testified that the Public Staff believes the Company should undertake a comprehensive rate design study prior to the filing of its next rate case to allow stakeholders the opportunity to participate in the discussion. The study should provide an analysis of each rate schedule to determine whether the schedule remains pertinent to current utility service, and should include whether the schedules should remain the same, be modified, or be replaced; the potential for new schedules to address the changes affecting utility service needs to be developed; and providing more rate design choices for customers. Tr. vol. 15, 968. Because cost of service studies and rate design are inextricably linked, witness Floyd testified that a cost of service study aligned with the current rate design portfolio of electric tariffs should be the beginning of the comprehensive rate study. Tr. vol. 15, 968, 1031.

Further, witness Floyd testified that rate designs should be rooted in a few broad principles that require rates to:

1. Be forward-looking and reflect long-run marginal costs.
2. Be focused on the usage components of service that are the most cost- and price-sensitive.
3. Be simple and understandable.
4. Recover system costs in proportion to how much electricity consumers use, and when they use it.
5. Give consumers appropriate information and the opportunity to respond to that information by adjusting their usage.
6. Where possible, be dynamic.

Tr. vol. 15, 968-69. According to witness Floyd, these guiding principles must provide consumers and users of the electric system: (1) the ability to connect to the utility system for no more than the cost of connecting to the grid; (2) pay for utility service in proportion to how much they use the system; and (3) for consumers and users who supply power to the utility system, fair and just compensation for the energy they supply. Each of these principles should be reflected in smarter rates. Tr. vol. 15, 969.

The Public Staff and DEP agreed to conduct a Comprehensive Rate Design Review in their Second Agreement and Stipulation of Partial Settlement that would cover at least the following topics, among others:

1. Firm and non-firm utility service, and the degree of customer-owned generation receiving both types of service.
2. Various types of end-uses such as electric vehicles ("EVs"), microgrids, energy storage, and distributed energy resources ("DERs").
3. The formats of future rate schedules (basic customer charges, demand charges, energy charges, etc.).
4. Marginal cost versus average cost rate designs and pricing.
5. Unbundling of average rates into the various functions of utility service (i.e., production, transmission, distribution, customer, general/administrative, etc.).
6. Socialization of costs versus categorization of specific costs and corresponding impact on rates/revenues.

DEP witness Lon Huber, Duke Energy's Vice President of Rate Design and Strategic Solutions, testified that he agreed with witness Floyd that the

Company should conduct a comprehensive rate design study, as well as with the six principles put forth by witness Floyd that should govern the study. Tr. vol. 11, 1156-57. On cross-examination, Witness Huber testified in support of a third-party-facilitated, comprehensive rate design review with broad stakeholder engagement and report-outs. Tr. vol 11, 1212. With regard to the timing of the study, witness Huber testified that the Company proposes to complete the study within 12 months of the issuance of a final order in this case. Tr. vol. 11, 1158.

No witness testified in opposition to the comprehensive rate design study proposed by witness Floyd.

Discussion and Conclusions

The Commission agrees that in light of the trends facing the utility industry and the developments discussed in the testimony of witness Floyd, there is a need for a comprehensive rate design study. Accordingly, the Public Staff and the Company shall jointly initiate a Comprehensive Rate Design Study, overseen by the Commission and with the participation of other interested stakeholders. As recommended by Public Staff witness Floyd, the study shall provide 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; the potential for new schedules to address the changes affecting utility service; providing more rate design choices for customers; and exploring the feasibility of consolidating the rates offered by DEC and DEP. The participants in the study shall be guided by the principles articulated by witness Floyd and by the changes ordered by the Commission to the allocation of distribution plant costs in the Company's COSS (adoption of basic customer method and allocation of demand-related distribution costs to rate classes on the basis of each class's diversified peak demand). In addition, the Comprehensive Rate Design Study should consider appropriate, cost-based BCCs for the non-residential rate classes following the adoption of the basic customer method to be submitted for consideration in the Company's next general rate case. Any parties to this general rate case will be considered stakeholders for the Study. The Study shall commence within thirty days of entry of this Order, shall be independently facilitated, shall take into consideration the conclusions of the Affordability Stakeholder Group, shall submit quarterly reports to the Commission, and conclude with a report to the Commission filed in this docket no later than one year from the entry of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 - 9

The evidence supporting these findings and conclusions is contained in the Second Agreement and Stipulation of Partial Settlement between the Company and Public Staff, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Affordability Stakeholder Process Testimony

Company witness De May provided testimony regarding the Company's low-income programs. In his testimony witness De May called for convening a stakeholder process to develop an appropriate suite of effective affordability options for the Commission to consider for approval. Tr. vol. 11, 758.

Public Staff witness Floyd testified that affordability is an important issue for both residential and non-residential customers. Tr. vol. 15, 989. Witness Floyd testified that he believes an affordability stakeholder process would be the appropriate venue to address public policy relating to affordability and rate design issues. Id. Witness Floyd outlined five parameters to guide the stakeholder process, including:

1. Set a timeline for the process, including a deadline to file recommendations with the Commission.
2. Investigate how affordability has changed over time and seek to define it for the purposes of utility service today.
3. Investigate the success of existing rates, assistance, and energy efficiency programs to address affordability.
4. Analyze data related to load, cost, and revenue profiles of low-income customers and the residential class, cost-causation, impacts to cost-of-service, potential for subsidization, impact on revenues and rates for all customers, program eligibility, extent of assistance needed to be meaningful, definition of a "successful program," etc.
5. Require periodic reporting to the Commission on the status of the process.

The Public Staff and DEP agreed to these general parameters in their Second Agreement and Stipulation of Partial Settlement.

Justice Center et al. witness Howat applauded Company witness De May for recognizing the need to do more to support low-income bill affordability and evidence tending to demonstrate that many of the Company's customers currently struggle to afford electric utility service. Tr. vol. 14, 373-82; Official Exhibits vol. 14, 234-42 (Ex. JH-2). Witness Howat testified regarding potential bill affordability programming. Tr. vol. 14, 373-92. Witness Howat noted that an effective bill affordability program should serve all residential customers at or below 150% of the federal poverty level eligible to participate in the Low Income Home Energy Assistance Program (LIHEAP), lower program participants' electricity burdens to an affordable level, promote regular, timely payment of electric bills by program participants, comprehensively addresses payment problems associated with program participants' current and past-due bills, be funded through a mechanism that is reliable while providing sufficient resources to meet policy objectives over an extended timeframe, and is administered efficiently and effectively. Id. at 377-78.

Witness Howat specifically described three effective affordability programs: a flat percentage discount of at least 25%, a tiered discount setting payments at a targeted electricity burden of approximately 5%, and a Percentage of Income Payment Plan (PIPP). Tr. vol. 14, 378-79. Under the flat discount model, customer's total utility bill is reduced by a specified percentage or dollar amount. Tr. vol. 14, 384-85. A tiered discount applies a different level of discount depending on the customer's income or poverty level. Id. at 387. Under a PIPP program, customers pay a predetermined percentage of income for electric service. Id. at 386-87. Witness Howat noted that Duke Energy has experience implementing a PIPP program in its Ohio territory. Id. at 386; Tr. vol. 10, 147; Official Exhibits vol. 14, 243 (Ex. JH-3). Witness Howat testified that Commissions in other jurisdictions have enacted similar affordability programs without prior legislative approval, including Ohio, Colorado, Massachusetts, and California. Justice Center et al. Late Filed Exhibit No. 2 (Sept. 28, 2020).

Witness Howat further testified that in order for any affordability program to be successful it must address arrearage balances. Tr. vol. 14, 379-81. Without addressing arrearages, witness Howat testified that any energy burden reductions associated with affordability programming will not result in long-term household energy security. Id. Witness Howat testified regarding two arrearage management models that have been implemented in other jurisdictions: a write-down of arrears over time after timely payments on current bills and a one-time retirement of arrearage balances. Id. at 380-81. Witness Howat recommended adopting an arrearage management program that provides low-income rate participants with a write down of one-twelfth of a pre-program overdue balance with each timely payment of a current monthly bill. Id. at 381.

Witness Howat testified that automatic enrollment of participants is a key feature of many affordability programs. Tr. vol. 10, 148-49. This automatic enrollment can be based on various forms of public assistance and has been implemented in various other jurisdictions. Tr. vol. 10, 148. Witness Howat provided specific examples of automatic enrollment programs in New Jersey, Massachusetts, and New York. Justice Center et al. Late Filed Exhibit No. 3 (Sept. 28, 2020). Witness Howat testified that these enrollment options would reduce the administrative burden of the programs and help meet the objectives of the programs. Tr. vol. 10, 149.

Discussions and Conclusions

The Commission appreciates that many parties agree on the critical importance of maintaining affordable electricity service for all of the Company's customers. The parties do not dispute that there are many customers that currently struggle to afford their electricity bill. The Commission agrees with witness Howat that the current number of customers faced with high energy burdens is unacceptably high.

The Commission also appreciates the willingness of all parties to enter into a collaborative process to address these issues. The Commission agrees with witness Floyd that there need to be parameters laid out by the Commission prior to engaging in this stakeholder process to ensure that it is productive. As a result, the Commission has ordered specific areas that must be explored during the stakeholder process, including disconnections for nonpayment, arrearages, late fees, usage data and energy intensity data by income levels and geography. The Commission finds and concludes that the affordability stakeholder process should consider suggestions made by witness Howat regarding (1) affordable rate design, including a Percentage of Income Payment Plan (PIPP), a flat percentage discount for qualified customers, and a tiered percentage discount; (2) arrearage management with debt forgiveness; and (3) automatic enrollment options.

The Commission also agrees with witness Floyd that specific timelines and deliverables are critical to the success of the stakeholder process. The Commission notes that it has previously ordered deliverables and timelines in other collaborative processes. Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, Docket No. E-7, Sub 1192 (Oct. 18, 2019) (requiring the DEC/DEP Energy Efficiency Collaborative to meet bi-monthly); Order Approving DSM/EE Rider and Requiring Filing of Customer Notice, Docket

No. E-7, Sub 1164 (Sept. 11, 2018) (order DEC/DEP Energy Efficiency Collaborative to consider specific program recommendations made by witnesses and requiring reporting on the outcomes of discussions). Therefore, the Commission finds good cause to order the stakeholder process to consider the recommendations laid out in the testimony of witness Howat, to report on the results of those discussions, to forward any resulting recommendations to the Comprehensive Rate Design Study, and to periodically meet to re-evaluate the recommendations.

The Commission commends the parties for proffering innovative solutions to solving these issues. The Commission agrees with witnesses De May, Floyd, and Howat that consideration of these public policy goals are a valid use of the Commission's authority. The Commission notes the examples proferred by witness Howat of jurisdictions where these types of innovative solutions were put into place by public utilities commissions without prior legislative approval. The Commission finds that its broad rate-setting authority and the obligations of universal service set forth in the Public Utilities Act can allow for new affordability programs and rate designs.

In summary, the Commission finds good cause to require the Commission staff to organize and facilitate an Affordability Stakeholder Process within 30 days of the date of this Order. Further, the Commission finds good cause to require the participants of the process to assemble and review data on affordability, energy burdens, and energy security in DEP's service territory, formulate recommendations on new programs, rate designs, arrearage management systems, and energy efficiency programs at a sufficient scale to meet the identified need within 180 days. The rate design and arrearage management recommendations should also be considered in the Comprehensive Rate Design Study. Finally, to ensure the recommendations are being successfully implemented, the stakeholder groups shall reconvene at least once annually to evaluate the programs and report to the Commission whether any changes are required.

IT IS, THEREFORE, ORDERED as follows:

1. That DEP shall discontinue the use of the minimum system method for allocating distribution plant costs and instead adopt the basic customer method in its COSS. Under the basic customer method, customer-specific costs (service drop, meter, billing, customer service) are classified as customer-related and the shared distribution plant (FERC Accounts 364 to 368) is classified as demand-related.

2. DEP shall not revert to use of the minimum system method in its COSS in future rate cases without first making an affirmative showing to the Commission that changed circumstances warrant a reevaluation of this decision.

3. That DEP shall discontinue the use of a non-coincident peak demand allocator when allocating demand-related distribution costs in its COSS and instead allocate demand-related distribution costs on the basis of class diversified peak.

4. That DEP shall increase residential class base revenues on a percentage basis by no more than the system-average increase otherwise allowed by this Order.

5. That DEP shall decrease the monthly Basic Customer Charge (BCC) for residential rate class from $14.00 to an average of $9.63, consistent with the adoption of the basic customer method in the Company's COSS and the removal of uncollectible expenses from the BCC. The Company shall recalculate the BCCs for the residential rate class schedules consistent with the basic customer method, with any difference from the current BCC recovered through the volumetric rate.

6. The Companies shall work with stakeholders in the Comprehensive Rate Design Review process to determine appropriate, cost-based BCCs for the remaining rate class schedules without the use of the minimum system method for consideration by the Commission in the Company's next general rate case.

7. That DEP and the Public Staff shall commence a Comprehensive Rate Design Review consistent with the parameters set forth herein within thirty days of this Order.

8. That DEP shall commence an Affordability Stakeholder process consistent with the parameters set forth herein within thirty days of this Order.

ISSUED BY ORDER OF THE COMMISSION.

This the ___ day of __________, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kim Campbell, Chief Clerk

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Joint Proposed Order by North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, North Carolina Sustainable Energy Association and Vote Solar as filed today in Docket No. E-2, Sub 1219 has been served on all parties of record by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.

This 4th day of December, 2020.

/s/ David Neal