BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1300

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**JANICE D. HAGER**
For Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North	)	**PROGRESS, LLC**
Carolina and Performance-Based Regulation	)	

I. INTRODUCTION AND PURPOSE

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

A. My name is Janice D. Hager, and my business address is 2049 Mount Zion Church Road, Alexis, North Carolina 28006. I am President of Janice Hager Consulting, LLC.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I have extensive experience with Duke Energy Corporation ("Duke Energy") over a 34-year career with Duke Energy. I am a civil engineer, having received a Bachelor of Science in Engineering from the University of North Carolina at Charlotte. During my time at Duke Energy, I was a registered professional engineer in North Carolina and South Carolina. I worked in Duke Power's (now Duke Energy Carolinas, LLC ("DEC")) Rates and Regulatory Affairs area for ten years, the last three of which I was Vice President of the department. Following the merger of Duke Energy and Progress Energy, Inc., I led Duke Energy's integrated resource planning process for all of Duke Energy's regulated utilities, including Duke Energy Progress, LLC ("DEP" or the "Company") and DEC. At the time of my retirement in December 2014, I was Vice President of Integrated Resource Planning and Analytics for Duke Energy. I am now President of Janice Hager Consulting LLC where I provide consulting services to Duke Energy and others.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have filed testimony and appeared before this Commission many times, including on matters of Fuel Adjustment Clauses, Integrated Resource Planning, Certificates of Public Convenience and Necessity, general rate cases, and other issues. I most recently testified before this Commission in the DEP and DEC general rate cases in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214, respectively. I have also appeared before the Public Service Commission of South Carolina, the Indiana Utilities Regulatory Commission, and the Federal Energy Regulatory Commission ("FERC").

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

A. My testimony describes and supports the allocation of DEP's electric operating revenues and expenses and original cost rate base assigned to the North Carolina retail jurisdiction and to each customer class according to the cost of service studies performed by the Company.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR TESTIMONY.

A. I provide an overview of how the Company has developed its cost of service studies, including the allocation of costs. I also describe the Agreement and Stipulation of Partial Settlement between DEP, DEC, the Public Staff – North Carolina Utilities Commission, Carolina Industrial Group for Fair Utility Rates II, and Carolina Industrial Group for Fair Utility Rates III dated September 9, 2022 (the "Stipulation"),[1] the changes to the cost of service as a result of the Stipulation, and why the changes are reasonable.

Q. PLEASE DESCRIBE THE COMPONENTS OF THE STIPULATION.

A. First, the Stipulation provides that production and transmission demand costs are allocated to the North Carolina retail jurisdiction using the Twelve Coincident Peak ("12 CP") method and to North Carolina retail rate classes using a modified average and excess ("A&E") demand method (the "Modified A&E Method"). Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. The Stipulation also provides that for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, the Company will make an adjustment to exclude certain curtailable/interruptible loads if they were not curtailed at the twelve system peak hours during the test year. The Stipulation only applies to this case for DEP and to Docket No. E-7, Sub 1276 for DEC, and parties are free to advocate for different methodologies in future cases.

Q. DO YOU BELIEVE THE STIPULATION IS REASONABLE AND SHOULD BE APPROVED BY THE COMMISSION?

A. Yes. The Stipulation is the result of the give-and-take inherent in coming to a settlement with parties with diverse views on appropriate methodologies and I

[1] The Stipulation was filed on September 13, 2022 in Docket Nos. E-2, Sub 1300 and E-7, Sub 1276.

believe the resulting method is a reasonable way to allocate costs in this case. In my testimony, I offer support for various components of the Stipulation.

The 12 CP method utilizes an average of the test year's twelve monthly peaks which helps ensure rate stability from test period to test period and helps mitigate the weather effects that impact a single coincident peak. In addition, the Company's planning process has shifted away from an emphasis solely on summer peaks, which makes 12 CP a reasonable choice for the allocation to the North Carolina retail jurisdiction in this case.

The A&E method considers that generation facilities are needed to serve a utility's "average load," as well as its "excess or peak load," in assigning responsibility for the recovery of production demand-related costs. The A&E Method is a common method, used in a number of jurisdictions. I conclude it is a reasonable method for the allocation of demand-related production costs to the North Carolina retail rate classes in this case.

Since the Company can curtail interruptible service so that it does not contribute to the system peak, interruptible load does not determine how much the Company must invest in capacity to meet the system peak. Therefore, it is reasonable to exclude certain curtailable load in the development of production demand allocation factors.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes. I have included the following exhibits:

- Hager Exhibit 1 provides the calculation of the three tests FERC uses for determining whether the 12 CP method is appropriate for the allocation of demand-related production and transmission costs. This exhibit demonstrates that the Company's 2021 demands meet FERC criteria for the Twelve Coincident Peak method under all three tests. Hager Exhibit 1 also provides these test results for the period of 2018 through 2020.

- Hager Exhibit 2 provides a description of load that has been removed to exclude curtailable/interruptible load in the development of the production fixed cost demand allocation factors.

Q. WERE EXHIBITS 1 AND 2 PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. Exhibits 1 and 2 were prepared under my direction and supervision.

II. <u>COST OF SERVICE STUDY OVERVIEW</u>

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A. The purpose of a cost of service study is to align the total costs incurred by DEP in the test period with the jurisdictions and customer classes responsible for the costs. The study directly assigns or allocates the Company's revenues, expenses, and rate base among the regulatory jurisdictions and customer classes served by the Company based upon the service requirements of those respective jurisdictions and customer classes. These service requirements are based on several factors, including differences in usage patterns and size.

Cost causation is a key component in determining the appropriate assignment of revenues, expenses, and rate base among jurisdictions and customer classes. Under the principle of cost causation, costs are assigned to the specific jurisdictions and customer classes that "caused" such costs to be incurred.

Once all costs and revenues are assigned, the study identifies the return on investment the Company has earned for each customer class during the test period. These returns can then be used as a guide in designing rates to provide the Company an opportunity to recover its costs and earn its allowed rate of return.

Q. SHOULD THE COST OF SERVICE STUDY FULLY ALLOCATE COSTS AMONG JURISDICTIONS AND CUSTOMER CLASSES?

A. Yes. As the cost of service study is used as a guide in designing rates, all costs must be allocated to the appropriate jurisdiction and customer class. If any costs are omitted or remain unallocated then the utility's rates will not allow for full recovery of the Company's operating expenses, including its approved cost of capital.

III. <u>REVIEW OF DEP'S COST OF SERVICE STUDY</u>

Q. HAVE YOU REVIEWED THE COST OF SERVICE STUDIES PREPARED BY DEP FOR FILING IN THIS CASE?

A. Yes. As referenced by Witness LaWanda Jiggetts in her pre-filed direct testimony, I have reviewed DEP's cost of service studies that were prepared and filed as Item 45 in the Company's Form E-1 filing in this case.

Q. WHAT IS THE SOURCE OF THE COST COMPONENTS THAT ARE REFLECTED IN DEP'S COST OF SERVICE STUDY USED TO SUPPORT THE REQUESTED RATE INCREASE?

A. The cost of service study is based on the official accounting books and records of DEP, supported in this proceeding by Witness Nicholas Speros. The cost components are comprised of the Company's electric operating expenses and original cost rate base and are based on the historical 12-month period covering January 1, 2021 through December 31, 2021 (the "Test Period").

IV. COST OF SERVICE STUDY PREPARATION

Q. PLEASE EXPLAIN HOW COSTS WERE ASSIGNED TO THE DIFFERENT JURISDICTIONS AND CUSTOMER CLASSES IN THE COST OF SERVICE STUDY IN SUPPORT OF THIS RATE CASE.

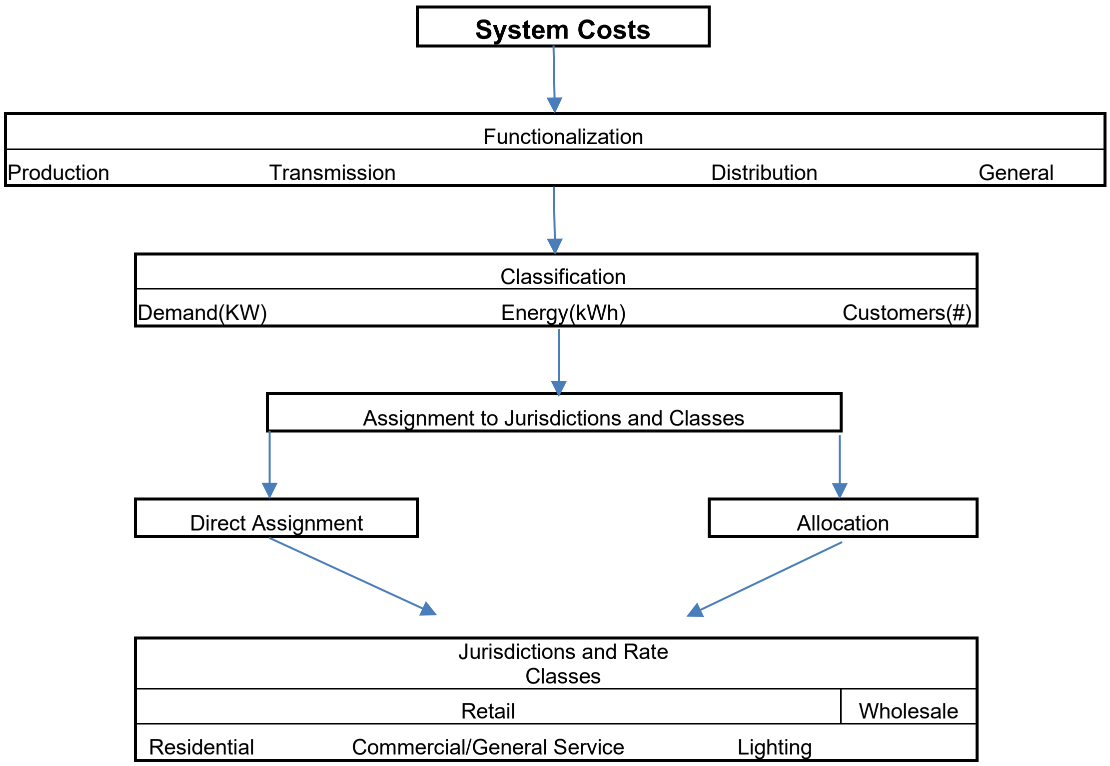
A. Generally, there are three key activities that occur when assigning costs in a cost of service study:

A. Costs are grouped according to their "function." Functions include production (generation), transmission, distribution, and customer service, billing, and sales.

B. Functionalized costs are then grouped or classified based on the utility "operation" or service being provided and the related causation of the costs. Typical classifications include demand, energy, and customer-related costs.

C. Finally, the costs, which have been functionalized and classified, are allocated or directly assigned to the proper jurisdiction and customer class based on the manner in which the costs are incurred (*i.e.,* based on cost causation principles).

The chart below provides a pictorial representation of this process:



A. Functionalizing Costs

Q. PLEASE EXPLAIN HOW TO FUNCTIONALIZE COSTS.

A. The Company accounts for its costs using FERC's Uniform System of Accounts ("USOA"). The USOA assigns the costs of the Company's plant investment into the primary categories of production (generation), transmission, distribution, and general and intangible plant. Similarly, the USOA categorizes the Company's operating costs into production, transmission, distribution, customer services, and administrative and general functions.

B. Classifying Costs

Q. PLEASE EXPLAIN HOW COSTS ARE CLASSIFIED.

A. Functionalized costs are classified according to their cost-causation characteristics. These characteristics are typically defined as demand-related, energy-related, or customer-related.

Q. PLEASE DEFINE DEMAND-RELATED COSTS.

A. Demand-related costs are costs incurred that vary in direct relationship to the kilowatts ("kW") of demand that customers place on the various segments of the system. Costs that are classified as demand-related include major portions of the Company's investment and related expenses in its production and transmission facilities, and a significant portion of the investment and related expenses of its distribution system. These costs tend to remain constant over the short run and do not change based on the amount of energy consumed. These costs are often referred to as fixed costs.

Q. PLEASE DEFINE ENERGY-RELATED COSTS.

A. Energy-related costs are costs incurred that vary in direct relationship to the amount of energy or kilowatt-hours ("kWh") generated and delivered. These costs are often referred to as variable costs.

Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

A. Customer-related costs are costs incurred as a result of the number of customers being served. Customer costs do not vary with the customers' volume of usage but are related to the number of customers.

C. Allocation and Direct Assignment of Costs

Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED AND DIRECTLY ASSIGNED.

A. Cost components identified as having a direct relationship to a jurisdiction or customer class are directly assigned to that jurisdiction or class before any allocations occur. For example, many distribution-related costs are directly assigned to a jurisdiction based on their state location. For these costs and for the remaining unassigned costs, specific allocation factors are developed that relate to the (1) demand, (2) energy, and (3) customer-related classifications identified above.

1. Demand Allocators

Q. WHAT DEMAND ALLOCATORS ARE USED TO ASSIGN DEMAND COSTS TO JURISDICTIONS AND CUSTOMER CLASSES IN THIS CASE?

A. There are two categories of demand-related costs used in the cost of service study:

a. <u>Production & Transmission Demand</u> – In accordance with the Stipulation, production and transmission demand-related costs are allocated to the jurisdictions using the 12 CP method and then production demand-related costs are allocated to North Carolina retail rate classes using the Modified A&E Method. Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation.

b. Distribution Demand – Distribution plant investments are directly assigned to the jurisdictions. At the customer class level, substations, and a part of poles, lines and transformers that have been designated as demand-related are allocated based on the Non-Coincident Peak ("NCP") demand.

a. Production and Transmission Costs

1. 12 CP

Q. PLEASE EXPLAIN THE CONCEPT OF ALLOCATING COSTS BASED ON COINCIDENT PEAK.

A. A peak responsibility allocator assigns the fixed demand-related costs (for example, a portion of production and all transmission-related costs) to the jurisdictions and/or customer classes in proportion to their respective contribution to the system's peak demand(s) for the same hours during the test period. Each jurisdiction and/or customer class's cost responsibility (*i.e.*, the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and/or customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. There are a number of different peak demand allocators that can be used to allocate fixed demand-related costs. These include single coincident peak ("1 CP"), two coincident peaks ("2 CP"), four coincident peaks ("4 CP"), and 12 CP.

Q. WHICH COINCIDENT PEAK METHODOLOGY IS DEP PROPOSING IN THIS PROCEEDING?

A. Per the Stipulation, the cost of service study supporting the Company's proposed rate design in this proceeding allocates the fixed portion of production and transmission demand-related costs to the North Carolina retail jurisdiction based upon each jurisdiction's coincident peak responsibility occurring during the test year's twelve monthly peaks, otherwise known as the 12 CP allocator.

Q. DID THE COMPANY RECOMMEND THE 12 CP ALLOCATOR IN ITS LAST GENERAL RATE CASE?

A. No. In Docket No. E-2, Sub 1219, the Company recommended, and the Commission approved, the Summer Coincident Peak ("Summer CP") method.

Q. PLEASE EXPLAIN WHY MOVING TO 12 CP FOR ALLOCATION TO THE JURISDICTIONS PER THE STIPULATION IS REASONABLE.

A. For the past several years, DEP has been monitoring the monthly peaks, as well as the key drivers for and the amounts of investments in production plant, in order to identify if and when a different allocation method should be proposed in future rate cases. Given the reasons discussed below, the Company believes now is the appropriate time to move from Summer CP to 12 CP.

There are several reasons why the Company believes the settlement provision to use 12 CP instead of Summer CP is appropriate, including:

- The Company's integrated resource planning process has shifted away from an emphasis solely on summer peaks.

- By averaging the twelve monthly peaks, the 12 CP method is less volatile than a single coincident peak, particularly in regard to weather.
- The 12 CP method is regularly used by utilities in allocating costs to customers and has been approved by state utilities commissions and the FERC.[2]

Q. HOW HAS THE COMPANY'S INTEGRATED RESOURCE PLANNING EVOLVED OVER THE PAST FEW YEARS?

A. Historically, DEP conducted integrated resource planning by focusing on the summer peak demand and the resources needed to meet that load plus an adequate planning reserve margin. However, beginning in 2016, DEP began focusing more on the winter-peak generation resource planning. A key driver for this change is the fact that the load and resource balance has changed drastically in the past few years, driven primarily by the high penetration of solar resources as well as the significant load response to recent cold weather. High levels of solar penetration do not meaningfully contribute to DEP's ability to meet winter peak load. As a result, since 2016 the Company's need for planning reserves has continued to shift primarily to the winter season. By focusing on the winter peak load and the required winter reserve margin, the Company can assure that the peak loads in all other months, including the summer peak, are met. The embedded resources in the cost of service study

[2] For example, several of DEP's FERC-approved wholesale contracts utilize some form of a 12 CP allocation method. In addition, several utilities in the Southeast – including Georgia (Georgia Power Company), Kentucky (Duke Energy Kentucky and Kentucky Power Company), Louisiana (Entergy Gulf States and Entergy Louisiana), Mississippi (Entergy Mississippi and Mississippi Power Company), Virginia (Old Dominion Power Company), and West Virginia (Appalachian Power Company and Monongahela Power Company) – use 12 CP.

were added under both planning methods (before and after 2016). Using the 12 CP method appropriately captures the impact of both the summer and winter peaks in the planning process without the weather volatility of an individually peaky summer or winter and recognizes that the IRP process ensures resources are available to serve peak loads in all months.

Q. WHAT TESTS HAS FERC ESTABLISHED TO DETERMINE WHETHER 12 CP IS THE APPROPRIATE METHOD?

A. While FERC has not established a "hard and fast rule for determining which allocation method is appropriate,"[3] it has established three basic tests based on a utility's load for determining which peak allocation method is appropriate.[4] In particular, the tests focus on whether a 12 CP allocation methodology is appropriate for the utility. In *Golden Spread Electric Cooperative, Inc.*, FERC offered quantitative guides for using the three tests.[5]

1. On and Off Peak Test – This test compares the average of the system peaks during the purported peak period (1 CP, 2 CP, etc.) as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak. A 12 CP allocation is considered appropriate when the difference between

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[3] *See Illinois Power Co.*, 11 FERC ¶ 63,040, ¶ 65,247 (1980) (*Illinois Power Initial Decision*), *aff'd*, 15 FERC ¶ 61,050 (1981).
[4] Michael E. Small, *A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers* 103, 106-110 (3rd ed. 1994).
[5] *Golden Spread Electric Cooperative, Inc., et al*, 123 FERC ¶ 61,047, ¶ 61,249 (2008).

these two percentages (the peak and non-peak seasons) is 19% or less.[6]

2. Low-to-Annual Peak Test – This test evaluates the annual variation in monthly system peaks. It compares the lowest monthly peak as a percentage of the annual system peak. If the percentage is 66% or higher, then the annual variation in monthly peaks is not large enough to warrant the use of a seasonal CP and, therefore, the use of a 12 CP approach is more appropriate.[7]

3. Average to Annual Peak Test – This test evaluates the variation between the average annual monthly peaks and the annual system peak. It compares the average of the twelve monthly peaks as a percentage of the annual system peak. A percentage of 81% or higher is considered indicative of a 12 CP system.[8]

The table below shows the results of these tests for the Company's 2021 cost of service adjusted production demands. For the On and Off-Peak test,

[6] FERC has held that, in general, a 19-percentage point or less difference between these two figures indicates that using the 12 CP demand allocation methodology is appropriate. *See Illinois Power Co*., 11 FERC ¶ 63,040, ¶ 65,248-49 (1980) (*Illinois Power Initial Decision*), *aff'd*, 15 FERC ¶ 61,050 (1981) (comparing average summer peak of 94% of annual peak to eight-month average peak of 75% of annual peak, a difference of 19 percentage points).

[7] FERC has held that a range of 66% or higher is indicative of a 12 CP system. *See id.* (approving 12 CP where lowest monthly peak as percentage of annual peak was 66%); *Delmarva Power & Light Co.*, 17 FERC ¶ 63,044, at 65,201 (1981) (*Delmarva Initial Decision*), *aff'd*, Opinion No. 185, 24 FERC ¶ 61,199, *reh'g denied*, Opinion No. 185-A, 24 FERC ¶ 61,380 (1983) (stating that for the Low to Annual Peak test, a low percentage indicates a load curve with a clearly defined peak, while a high percentage indicates a flatter load curve).

[8] FERC has held that the range indicating whether a utility is to be considered a 12 CP system is 81% or higher. *See Illinois Power Initial Decision*, 11 FERC ¶ 63,040, ¶ 65,249 (1980) (approving 12 CP where average monthly peak for five-year period was 81%); *Lockhart Power Co*., Opinion No. 29, 4 FERC ¶ 61,337, ¶ 61,807 (1978) (approving 12 CP where average monthly demand was 84% of annual system peak); *El Paso Elec. Co*., Opinion No. 109, 14 FERC ¶ 61,082, ¶ 61,147 (1981) (approving 12 CP where twelve-month average was 84% of maximum peak).

Summer CP is used for comparison since that is the method the Company has used in the past as approved by the Commission. This table demonstrates that the Company's 2021 production demands meet FERC criteria for the 12 CP method under all three tests.

Table A

Test 1 On and Off Peak		Test 2 Low to Annual		Test 3 Average Annual to Peak	
1-CP Summer:		**Low Peak**	8,762	**Annual Average**	10,685
Summer Peak	12,220	**Annual Peak**	12,220	**Annual Peak**	12,220
Average Off Peak	10,546	**Low/Annual**	71.7%	**Average/Annual**	87.4%
System Peak	12,220				
Percent of System Peak:					
Peak/Annual Max	100.0%				
Off-Peak/Annual Max	86.3%				
Difference	13.7%				
Test supporting 12CP:	max 19.0%	**Test supporting 12CP:**	min 66.0%	**Test supporting 12CP:**	min 81.0%
Result: 12 CP Supported		**Result:** 12 CP Supported		**Result:** 12 CP Supported	

Hager Exhibit 1 provides the calculation of these three tests for the Company's 2018 through 2021 cost of service adjusted production demands.[9] The Exhibit includes in the On and Off-Peak test five different demand allocation methodologies for each of the four years. The results for the On and Off Peak test demonstrate that the 12 CP method is a better fit than the 1 CP, 2 CP, or 4 CP method.

Q. DOES FERC PRECEDENT DICTATE WHAT THE NORTH CAROLINA UTILITIES COMMISSION DOES?

A. No. However, I believe the tests discussed above can be a helpful tool to this Commission in determining the appropriate allocation method.

[9] The adjustments made are discussed below.

Q. WHEN DID THE TWELVE MONTHLY COINCIDENT PEAK DEMANDS USED IN THIS STUDY OCCUR?

A. DEP's generation and transmission twelve monthly peaks occurred on:

Day	Month	Date	Time (hour ending)	Peak (MW)
Friday	January	29	8:00AM	11,873
Thursday	February	4	8:00AM	11,796
Monday	March	8	8:00AM	10,560
Saturday	April	3	8:00AM	9,118
Wednesday	May	26	4:00PM	11,062
Monday	June	21	5:00PM	11,823
Friday	July	30	4:00PM	12,124
Thursday	August	12	5:00PM	12,655
Wednesday	September	8	4:00PM	11,092
Tuesday	October	5	4:00PM	9,415
Tuesday	November	30	8:00AM	11,323
Wednesday	December	13	8:00AM	10,426

Q. ARE THE PEAKS DESCRIBED ABOVE THE SAME ONES USED IN THE COST OF SERVICE STUDIES?

A. No. DEP's system peaks are adjusted when developing production and transmission demand allocators for the cost of service. As in the Company's most recent rate case, DEP made adjustments to remove demands related to Company use and other transactions not considered part of native load, including a peaking NCEMC sale. In addition, in this case, the Company has made an adjustment to exclude certain curtailable/interruptible loads from production demands that were not curtailed at those system peak hours during the test year consistent with the Stipulation. This adjustment is described below.

2. Modified A&E Method

Q. PLEASE DISCUSS THE ALLOCATION METHOD USED TO ALLOCATE THE JURISDICTIONAL COSTS TO THE VARIOUS RATE CLASSES.

A. In accordance with the Stipulation, once the costs were allocated to North Carolina retail using the 12 CP method, DEP allocated demand-related production costs to the various retail rate classes using the Modified A&E Method.

Q. PLEASE EXPLAIN THE CONCEPT OF THE A&E ALLOCATION METHOD.

A. As noted in the Stipulation, A&E methods consider that generation facilities are needed to serve a utility's "average load," as well as its "excess or peak load," in assigning responsibility for the recovery of production fixed costs.[10] According to the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("CAM"), the A&E method "allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident demands."[11] The

[10] *See* Stipulation, at fn. 2.
[11] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January 1992, p. 49

concept behind the method is that generation facilities are needed to serve a utility's "average load," as well as its "excess or peak load." Under the A&E methodology, all groups of customers are allocated some portion of the production plant investment and "fixed" expenses related to the generation of power. A rate class's coincident peak demand is that class's load at the time of the system's peak demand. A rate class's non-coincident peak is the maximum demand regardless of the time of occurrence. Each rate class's non-coincident demand likely occurs at different times from other customer classes. The sum of the non-coincident class peaks is different from the systemwide peak demand.

Q. PLEASE DESCRIBE HOW THE ALLOCATION FACTORS ARE CALCULATED FOR THE A&E METHOD.

A. The A&E allocation demand factor is composed of two parts. The "average" demand for the test year is calculated by dividing the test year number of kWh by the number of hours in the test year (8,760 hours). The "excess" demand is the difference between average demand and peak demand. This excess is apportioned among the customer classes based upon the difference between the average demand and the highest demand of the customer class. The A&E factor for each class is the sum of the "average" and "excess" portions of the allocation factors for each rate class.

Q. HOW DOES THE MODIFIED A&E METHOD DIFFER FROM THE A&E METHODOLOGY INCLUDED IN THE NARUC CAM?

A. The Company had to adjust the CAM A&E Method to conform the A&E allocators to the 12 CP method at the North Carolina retail jurisdictional level.

Q. IS THE MODIFIED A&E METHOD A REASONABLE METHOD FOR ALLOCATING THE NORTH CAROLINA RETAIL JURISDICTIONAL PORTION OF THE DEMAND-RELATED PRODUCTION COSTS TO CUSTOMER CLASSES?

A. Yes. The A&E method is a commonly accepted method of allocating demand-related production costs.[12] As such, it is a reasonable method that I support in light of the Stipulation.

3. Removal of Certain Curtailable/Interruptible Loads

Q. WHAT SPECIFIC LOAD IS BEING REMOVED?

A. Please see Hager Exhibit 2 for a description of the interruptible/curtailable load that was removed.

Q. IS THIS A DEPARTURE FROM PAST COMPANY PRACTICE?

A. Yes. Historically, DEP has allocated production fixed costs in its cost of service studies based on the demands served at its peak hour. At the time of the peak demand, some interruptible load may have been served and some may have

[12] For example, several utilities in the South, including Virginia Electric and Power Company (d/b/a Dominion Energy Virginia), Entergy Arkansas, Oklahoma Gas and Electric Company (Arkansas), Southwestern Electric Power Company (Arkansas), Evergy Metro, Inc. (Missouri), El Paso Electric Company, Entergy Texas, Inc., Southwestern Public Service Company (Texas), and Southwestern Electric Service Company (Texas), use a version of the A&E method to allocate demand-related production costs among retail customer classes.

been interrupted. That is, in the past, no adjustments were made for interruptible service if it was not curtailed at the peak hour.

Q. PLEASE EXPLAIN WHY REMOVING CERTAIN CURTAILABLE LOAD PER THE STIPULATION IS REASONABLE.

A. The Company believes that aligning firm load with firm capacity to serve that load is more consistent with the principle of cost causation than the previous method. In the development of its annual Integrated Resource Plan, DEP does not plan for, nor purchase capacity for, the curtailable load of customers. Since the utility can curtail interruptible service so that it does not contribute to the system peak, interruptible load does not determine how much the utility must invest in capacity to meet the system peak. If all possible curtailable load is curtailed in the test year during system peaks, there is no need for adjustments; revenues and loads both reflect only firm load. However, there can be a mismatch between revenues and loads (and thus the calculated returns by rate class) if there is some non-firm load in the test year peaks. DEP has removed from the cost of service non-curtailed non-firm load present during the test year peaks where its presence would create a mismatch with revenues. This adjustment ensures a matching of firm load with firm load revenues. The Company's removal of interruptible load is also consistent with FERC precedent.[13] For example, in *Louisiana Public Service Commission*,[14] FERC determined:

[13] *See, e.g., Delmarva Power & Light Co.*, Opinion No. 189, 25 FERC ¶ 61,121; *Delmarva Power & Light Co.*, Opinion No. 185, 24 FERC ¶ 61,199 (1983).
[14] *La. Pub. Serv. Comm'n*, 106 FERC ¶ 61,228, ¶ 61,802 (2004).

> Since Entergy can curtail interruptible service so that it does not contribute to the System peak, interruptible load does not determine how much Entergy must invest in capacity to meet the System peak, i.e., its customers' needs. Therefore, under the peak load responsibility cost allocation methodology, Entergy should not include interruptible load in its calculations.

FERC reasoned that it was not whether load was interrupted, rather it was "the right to interrupt that is critical to the analysis…"[15] FERC concluded that this right meant "that customer shares no responsibility for capacity costs…."[16]

In addition, in its subsequent order denying rehearing, FERC affirmed its findings, and clarified that these findings are just as valid where, as with Entergy, a utility uses the 12 CP method, as opposed to a single coincident peak method:[17]

> We also disagree with the argument that the validity of our findings in Opinion No. 468 is somehow undercut by the fact that Entergy does not use [1 CP] peak load responsibility cost allocation method. The contention is refuted by careful reading of Opinion No. 468, … which recognizes Entergy uses [12 CP]…..

In other words, "Entergy, like most utilities, uses a peak load responsibility method to allocate fixed costs, and so its costs should be allocated based on which customers cause it to incur those fixed costs, i.e., firm customers and not

[15] *Id*. at ¶ 61,804 (emphasis in original).
[16] *Id*. (internal citation omitted).
[17] *La. Pub. Serv. Comm'n, reh'g denied*, 111 FERC ¶ 61,080, ¶ 61,370 (2005).

interruptible customers"[18] – this is true regardless of how many peaks a utility uses.[19]

As an additional example, in *Delmarva Power and Light Company*,[20] FERC approved Delmarva Power and Light's use of 12 CP and found that loads served under its "Q tariff" (Controllable Power Service) are interruptible and therefore should not be included in determining the percentage responsibility of each class under the approved 12 CP method. In so finding, FERC noted that it has determined that:

> … even a limited right of interruption, if it enables the company to keep a customer from imposing demands on the system during peak periods, gives a company the ability to control its capacity costs. Therefore, that customer shares no responsibility for capacity costs under a peak responsibility method.[21]

Q. IS THERE ALSO A BENEFIT OF REDUCED VOLATILITY IN THE PEAK LOAD ASSOCIATED WITH THE PROPOSED CHANGE?

A. Yes. Previously, the test year may or may not have had this interruptible load included in the peak depending on whether the load was or was not curtailed at the peak hour. The proposed method will eliminate the volatility of having the load in one test year and out the next test year.

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[18] *Id*.

[19] *See also La. PSC v. FERC*, 482 F.3d 510 (D.C. Cir.) (2007) (finding that FERC's inclusion of interruptible load in the formula for allocating peak load responsibility was unreasonable, acted arbitrarily and capriciously in allowing Entergy to phase that load out of its calculation."

[20] *Delmarva Power and Light Co.*, 24 FERC ¶ 61,199, ¶ 61,462 (1983).

[21] *Id*. at 61,462 (citing *Kentucky Utilities Co.*, 15 FERC ¶ 61,002, ¶ 61,004 (1981)). FERC also affirmed this finding in *Delmarva Power and Light Company*, 25 FERC ¶ 61,022, ¶ 61,121-22 (1983): "There is no evidence in this docket that would warrant a different result. Therefore, rate Q customers' demands shall not be considered in demand cost allocation."

Q. PLEASE SUMMARIZE HOW DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS WERE ALLOCATED.

A. The demand-related production costs were first allocated to the North Carolina retail jurisdiction using the 12 CP method, and then allocated to the North Carolina retail rate classes using the Modified A&E Method. In both steps, adjustments were made to remove certain curtailable load. The demand-related transmission costs were allocated to the rate classes based on 12 CP demand, without adjustment for curtailable load.

b. Distribution Costs

Q. HOW ARE DISTRIBUTION COSTS ALLOCATED?

A. Most distribution investments are first identified and directly assigned to the state in which they are located. Then those distribution costs identified as customer-related are allocated based on customer allocation factors, as discussed below. The remainder of the distribution costs are designated as demand-related and allocated to the customer classes based on NCP demand allocators.

The NCP allocators are developed 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 all customers' non-simultaneous peak demand. Several different NCP allocators are developed to account for the different levels of the distribution system where customers may take service (substation and below, primary and below, secondary, etc.). For example, only the NCP demand of customers who take service at secondary voltage is included in the development of the NCP allocator used to allocate secondary distribution lines and poles.

Q. WHY IS A NON-COINCIDENT PEAK USED FOR ALLOCATING DEMAND-RELATED DISTRIBUTION INVESTMENT?

A. Distribution facilities serve individual neighborhoods, rural areas, and commercial districts. They do not function as a single integrated system in meeting system peak demand. Instead, the distribution system serving each neighborhood, rural area, or commercial district must be able to meet the peak demand in the area it serves whenever the peak occurs. Accordingly, contribution to NCP is the appropriate measure of determining customers' responsibility for these costs because it best measures the factors that drive investment to support that part of the system.

2. Energy Allocators

Q. WHAT ALLOCATOR WAS USED TO ASSIGN ENERGY-RELATED COSTS TO JURISDICTIONS AND CUSTOMER CLASSES?

A. Energy-related costs reflect the variable cost of producing, transmitting, and delivering electricity. Examples of costs allocated on this basis are fuel costs and variable production costs incurred at generating stations. DEP's kWh of generation and deliveries during the Test Period have been used to allocate these variable costs. The kWh sales information is collected, and then adjusted for the level of losses attributable to each class and jurisdiction, to derive the level of kWh at the generator attributable to that class or jurisdiction.

3. Customer Allocators

Q. WHAT TYPES OF COSTS HAS DEP INCLUDED FOR ALLOCATION AS CUSTOMER-RELATED?

A. DEP has included operating expenses in FERC Accounts 901-917. These expenses include meter reading, billing and collection, and customer information and services. In addition, DEP has included in this category a portion of distribution costs that the Company has identified as customer-related. Within distribution plant, the Company identified as customer-related and allocated based on a customer allocator meters and service drops (FERC Accounts 369 and 370) and a portion of transformers (FERC Account 368). The Company has also identified a portion of the costs for distribution lines and poles (FERC Accounts 364-367) that are customer-related. The remaining distribution plant and associated costs were classified as demand-related, with the exception of Account 363, Energy Storage Equipment – Distribution.

Q. WHAT IS THE EXCEPTION TO THIS CLASSIFICATION?

A. Beginning in 2020, DEP has had a small balance related to batteries in distribution plant Account 363 (Energy Storage Equipment - Distribution). The balance in that account assigned to the North Carolina retail jurisdiction is approximately $11 million. Storage battery equipment that is functionalized to distribution (FERC Account 363) is allocated across customer classes using gross distribution plant excluding batteries. This approach recognizes that batteries can provide benefits to or support different parts of the distribution system.

Q. DO YOU BELIEVE INCLUSION OF A PORTION OF DISTRIBUTION LINE, POLE, AND TRANSFORMER COSTS IN CUSTOMER ALLOCATIONS IS REASONABLE AND APPROPRIATE?

A. Yes. The NARUC CAM states that a portion of distribution costs related to FERC Accounts 364-368 are customer-related. These FERC accounts include the costs of poles, towers, fixtures, overhead and underground conductors, and transformers. The two-methods the CAM discusses for allocating these customer-related distribution costs are:

1) Minimum System Method (called Minimum-Size Method in the CAM); and
2) Zero-Intercept Method (called Minimum-Intercept Method in the CAM).

Both methods recognize that some portion of the distribution system is necessary to serve customers, regardless of whether the customers take any energy from the system. The Minimum System Method seeks to determine the minimum size distribution system that can be built to serve the minimum loading requirements of customers. The Minimum System Method develops the cost of the minimum set of distribution assets that would be needed to serve customers and allocates those costs based on the number of customers.

Similar to the Minimum System Method, the Zero-Intercept Method allocates a portion of the same distribution accounts on the basis of the number of customers. The Zero-Intercept Method seeks to identify the portion of distribution plant that is associated with no load using regression techniques.

Q. WHICH METHOD DID DEP CHOOSE AND WHY?

A. DEP incorporated the concept of Minimum System into its cost of service study for allocating costs to customers, which is appropriate for allocation of customer-related distribution costs. The zero-intercept method is generally considered to be a more complex and time-consuming methodology that often can produce results that are not materially different from the Minimum System method. In addition, the data needed to do the calculation is not available in DEP's records. The theory behind the use of a minimum system study is sound and consistent with cost causation, which is the foundation of cost of service studies. DEP's Minimum System Study allowed DEP to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels). Every customer requires some minimum amount of wires, poles, transformers, etc. to receive service; therefore, every customer "caused" DEP to install some amount of such distribution assets. The concept DEP used to develop its Minimum System Study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb). This methodology allows the utility to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, if and when the customer chooses to use electricity. Once minimum system costs have been identified, all distribution costs over the minimum system costs and direct assignments are determined to be driven by demand.

Q. DID HOUSE BILL 951 SPEAK TO THE USE OF MINIMUM SYSTEM?

A. Yes. House Bill 951 states that:

> The Commission is authorized to approve performance-based regulation upon application of an electric public utility pursuant to the process and requirements of this section, so long as the Commission allocates the electric public utility's total revenue requirement among customer classes based upon the cost causation principle, **including the use of minimum system methodology** by an electric public utility for the purpose of allocating distribution costs between customer classes, and interclass subsidization of ratepayers is minimized to the greatest extent practicable by the conclusion of the MYRP period. This section shall not be construed to require the Commission to use the minimum system methodology for the purpose of classifying costs within a customer class when setting a basic facilities charge.[22]

The cost of service used by DEP in this proceeding is consistent with this provision of House Bill 951.

5. Fuel Cost Allocations

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE ALLOCATION OF FUEL COSTS IN THIS PROCEEDING?

A. Yes. N.C. Gen. Stat. § 62-133.2.(a2)(2) states:

> For the capacity costs described in subdivisions (5), (6), (10), and (11) of subsection (a1) of this section, the specific component for each class of customers shall be determined by allocating these costs among customer classes based on the method used in the electric public utility's most recently filed fuel proceeding commenced on or before January 1, 2017, as determined by the Commission, until the Commission determines how these costs shall be allocated in a general rate case for the electric public utility commenced on or after January 1, 2017.

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[22] N.C. Gen. Stat. § 62-133.16(b), emphasis added.

We consider this proceeding the appropriate forum for the Commission to reconsider the most appropriate cost allocation methodology for allocating purchased power capacity costs described in this subsection, which are to be requested for cost recovery in the Company's annual fuel proceeding. In the most recent general rate case, Docket No. E-2 Sub 1219, the parties settled on production plant as an appropriate allocation factor for these costs; however, the Company is proposing that the Commission reconsider production demand as the more appropriate cost allocation factor to allocate system purchased power capacity costs to North Carolina retail and across North Carolina retail customer classes.

The Company believes allocating purchased capacity costs on production demand is more appropriate than production plant. Purchase power capacity costs that are not recovered through the fuel clause are allocated on production demand so the change would align all purchase capacity costs under the same allocator. In addition, most production plant is allocated on production demand. The exception is certain jurisdiction specific amounts that are not related to purchase power costs.

V. <u>CONCLUSION</u>

Q. ARE THE COMPANY'S CHOSEN METHODOLOGIES TO ALLOCATE ITS DEMAND-RELATED, ENERGY-RELATED AND CUSTOMER-RELATED COSTS REASONABLE AND APPROPRIATE UNDER THE CIRCUMSTANCES?

A. Yes. They are.

Q. DOES THE COMPANY'S COST OF SERVICE STUDY USED FOR THIS CASE PROPERLY DISTRIBUTE COSTS OF PROVIDING ELECTRIC SERVICE TO CUSTOMER CLASSES?

A. Yes. It does. The cost of service study provides a proper foundation for distributing costs among the jurisdictions and customer classes because it recognizes cost causation and distributes costs accordingly. This study also provides a proper basis for determining cost-based rates and is a major component of fair and equitable rate design. The cost of service study also provides an accurate measure of profitability among classes of customers.

Q. DID YOU VERIFY THAT THE COST OF SERVICE INFORMATION YOU ARE TESTIFYING TO WAS USED IN DETERMINING HOW TO DESIGN PROPOSED RATES?

A. Yes. The North Carolina retail cost of service information, including the separation of the demand, energy, and customer components of cost, was used in developing the rate design proposed by DEP.

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

A. Yes.

FERC Screens for 12 CP Allocations
on DEP Adjusted Firm System Production Demands*

		System Peaks per Adjusted Firm Demands*				
Test # in FERC Order		**2018**	**2019**	**2020**	**2021**	**Times 12CP is a better fit in the last 4 years**
1) On and Off Peak Test: tested against the following Peak methods						
1-CP Summer:						
	Month of Peak	6	7	7	8	
	Peak/Annual Max	82.5%	93.8%	100.0%	100.0%	
	Off-Peak/Annual Max	74.1%	87.7%	81.7%	86.3%	
	Difference (12 CP at maximum 19%)	8.4%	6.1%	18.3%	13.7%	11.6%
Is 12 CP a better fit than 1-CP Summer?		Yes	Yes	Yes	Yes	4
1-CP Winter:						
	Month of Peak	1	1	1	1	
	Peak/Annual Max	100.0%	100.0%	92.2%	94.0%	
	Off-Peak/Annual Max	72.5%	87.1%	82.4%	86.8%	
	Difference (12 CP at maximum 19%)	27.5%	12.9%	9.8%	7.1%	14.3%
Is 12 CP a better fit than 1-CP Winter?		No	Yes	Yes	Yes	3
2-CP (S/W) Peaks:						
	Peak Min Month	6	7	1	1	
	Peaks/Annual Max	91.2%	96.9%	96.1%	97.0%	
	Off-Peak/Annual Max	71.5%	86.4%	80.7%	85.5%	
	Difference (12 CP at maximum 19%)	19.8%	10.5%	15.4%	11.4%	14.3%
Is 12 CP a better fit than 2-CP (S/W)?		No	Yes	Yes	Yes	3
4CP (2W, 2S) Peaks:						
	Peaks/Annual Max	83.8%	93.9%	94.4%	95.7%	
	Off-Peak/Annual Max	70.3%	85.3%	77.7%	83.3%	
	Difference (12 CP at maximum 19%)	13.5%	8.7%	16.7%	12.4%	12.8%
Is 12 CP a better fit than 4CP (2W, 2S)?		Yes	Yes	Yes	Yes	4
4CP Max Peaks:						
	Peaks/Annual Max	85.3%	94.5%	96.2%	95.7%	
	Off-Peak/Annual Max	69.5%	85.0%	76.8%	83.3%	
	Difference (12 CP at maximum 19%)	15.8%	9.4%	19.5%	12.4%	14.3%
Is 12 CP a better fit than 4CP Max ?		Yes	Yes	No	Yes	3
2) Ratio - Low to Annual Max:						
	Difference (12 CP minimum 66%)	50.3%	71.2%	62.1%	71.7%	
	12 CP a good fit?	No	Yes	No	Yes	2
	Month of Annual Max:	Jan	Jan	Jul	Aug	
3) Ratio - Average to Annual Max:	Difference (12 CP minimum 81%)	74.8%	88.2%	83.2%	87.4%	
	12 CP a good fit?	No	Yes	Yes	Yes	3

* Adjusted Firm Demands exclude the following from the DEP System Peaks published in FERC Form 1, page 401b:
1) NCEMC peaking sale, SEPA generation and DEP Company use that are excluded from DEP's native load for cost of service.
2) Generator step up losses as COS allocators are calculated at the high side of the GSU.
3) Curtailable demands that were not curtailed at the times of the monthly system peaks.
4) Demands related to the Camden wholesale sale that expired after 12/31/2020 were excluded for the entire 4 year period.

DEP Cost of Service - 2021
Retail Curtailable Load Removed
Units: KW at Production

		Annual Total						
Rate Schedule	State	Rider LLC	LGS-CUR-TOU	Rider 57	Rider IPS	Rider 68	Rider NFS	Total
NC MGS	NC	15,247	-	-	-	-	7,854	23,101
NC SGS	NC	-	-	-	-	-	4,511	4,511
NC LGS	NC	865,451	-	255,107	29,041	16,839	63,223	1,229,662
Total North Carolina Retail		880,698	-	255,107	29,041	16,839	75,589	1,257,274
SC MGS	SC	16,722	-	-	-	-	-	16,722
SC LGS	SC	93,733	879,374	-	118,535	-	-	1,091,642
Total South Carolina Retail		110,454	879,374	-	118,535	-	-	1,108,364
Total Retail Curtailable Load Removed		991,152	879,374	255,107	147,576	16,839	75,589	2,365,638

LGS-CUR-TOU -LARGE GENERAL SERVICE - CURTAILABLE SCHEDULE LGS-CUR-TOU
Rider LLC - LARGE LOAD CURTAILABLE RIDER LLC
Rider 57 - SUPPLEMENTARY & INTERRUPTIBLE STANDBY SERVICE RIDER
Rider IPS - INCREMENTAL POWER SERVICE RIDER IPS
Rider 68 - DISPATCHED POWER RIDER NO. 68
Rider NFS - SUPPLEMENTARY AND NON-FIRM STANDBY SERVICE RIDER NFS