PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

Docket No. E-100, Sub 162

Before the North Carolina Utilities Commission

Report of the Public Staff on the
Minimum System Methodology of
North Carolina Electric Public Utilities

Report of
March 28, 2019

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I. Purpose of Report and Background

Pursuant to the Commission's *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* issued in Docket No. E-7, Subs 819, 1110, 1146, and 1152, dated June 22, 2018 (2018 Rate Order), the Public Staff presents this report on its findings concerning the use of the minimum system methodology (MSM). Ordering Paragraph 38 of the 2018 Rate Order stated:

> "That the Public Staff shall facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose."

In compliance with the Commission's 2018 Rate Order, the Public Staff held meetings with Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Dominion Energy North Carolina (DENC). At his request, the Public Staff also met with David Neal, the attorney representing the North Carolina Justice Center (NC Justice Center), North Carolina Housing Coalition (NC Housing Coalition), Natural Resources Defense Council (NRDC), and Southern Alliance for Clean Energy (SACE) (collectively, NC Justice Center, et al.) to discuss the use of the MSM going forward.

After its initial meeting with the electric utilities, the Public Staff requested DEC, DEP, and DENC to provide the following information in written responses:

1. Provide an overview and explanation of the current methodology for distribution plant classification.
2. Provide the history of the Company's use of the Minimum System.
3. Provide the history of allocating distribution costs as demand- and customer-related.
4. Explain the Company's current allocation of distribution costs and why it is appropriate.
5. Should the basic customer method of allocating costs be adopted?
6. Explain any other options for allocating distribution costs as customer- or demand-related.
7. Provide the Company's recommendations.

The responses to these initial questions are shown in Appendix 1.

The Public Staff conducted additional discovery on DEC, DEP, and DENC regarding their approach to the MSM, calculations, and application. The Public Staff also reviewed information provided by Mr. Neal regarding the allocation of distribution plant and the MSM.

The Public Staff also reviewed the National Association of Regulatory Utility Commissioners' "Electric Utility Cost Allocation Manual" (NARUC Manual), published in January 1992, for guidance on the allocation of electric utility costs. The NARUC Manual continues to be considered an important resource for the calculation and allocation of electric utility cost of service for regulatory commissions, consumer advocates, and parties before the Commission testifying on issues of cost-of-service and rate design.

II. Overview of the Distribution System

The distribution portion of the typical electric power system is composed generally of wires, substations, transformers, and service connections that bring power to end-use consumers at a usable voltage level. Power generation resources are typically interconnected to the electric system by means of high voltage (100 kV and greater) transmission lines. Transmission-to-distribution substations “step down” these high voltages to what is recognized as the distribution components of the power delivery system. Customer meters represent the point at which the customer takes electric service from the utility. For accounting purposes, physical assets associated with the distribution system are assigned to specific FERC accounts and identified in cost of service studies,[1] as illustrated in Table 1.

Table 1. FERC Accounts Related to the Distribution System.

FERC Account	Distribution Asset
360-363	Substations & Equipment
364	Poles, Towers, Fixtures
365	Overhead Conductors & Devices
366	Underground Conduit
367	Underground Conductor & Devices
368	Line Transformers
369	Service Connections/Drops
370	Meters

[1] See Appendix 2 for a more detailed list and description of equipment included in each FERC account.

Residential customers, small to medium load non-residential customers, and most street and area lighting customers receive electric utility service from the distribution system. Larger non-residential customers, such as industrial customers, may receive service from either the distribution or transmission systems. This is an important distinction in the allocation of costs related to the distribution system. Under all cost-of-service methodologies, only customers receiving service at the distribution level are allocated costs associated with the distribution system.

III. Overview of the Cost of Service Study

The cost-of-service study (COSS) is a tool for calculating and demonstrating how utility costs are functionalized, classified, and allocated or directly assigned among jurisdictions and customer classes. Without this basic tool, the utility, its customers, and other interested parties are unable to establish the cost and revenue relationships the Commission relies upon to determine just and reasonable rates.

Data used in a COSS is based on the official accounting books and records of the utilities. This data includes the number of customers and meters, the demand or capacity (kilowatts or kW) recorded during peak load periods, and the total energy (kilowatt-hours or kWh) used to serve each customer class, all of which ultimately drive the costs that each jurisdiction and customer class imposes on the utility system. Much of this data has historically been obtained through load research and direct measurement. However, with the deployment of advanced metering infrastructure (AMI) and the availability of more granular AMI data, utilities are able to ascertain more clearly and specifically how their customers utilize, and impose costs on their systems, and how rates can be designed to better reflect the true cost causation of utility service provided.

The four major steps in developing the COSS are: (1) the functionalization of the utility system; (2) the classification of costs; (3) the determination and definition of the customer classes; and (4) allocation of costs to jurisdictions and customer classes. The end result of this exercise is the calculation of a revenue requirement and return on rate base for each jurisdiction and customer class, which will serve as the foundation of rate design.

The first step, functionalizing the utility's costs, is used to categorize the costs associated with each major electric utility service function. This includes the production (generation) facilities needed to meet peak loads and generate required energy; high voltage transmission facilities to interconnect production facilities with the distribution system; distribution facilities needed to step down voltages to usable levels for most customers and to interconnect customers; and customer services such as metering, billing, and account management.

The second step, classifying each functionalized cost category, identifies costs as either the result of electric use or by the number and type of customer. Costs driven by electric use can be characterized in one of two ways: demand or energy. Electricity demand is measured in kilowatts (kW) and represents a rate of use. The measurement of demand is similar to the speedometer of a car, which registers how fast you are driving at any point in time. Just as car speed can vary from moment to moment, so can demand for electricity. Energy is measured in kilowatt-hours (kWh) and is a measurement of demand over time. Energy use is analogous to the car's odometer. Just as the car's odometer measures the total distance travelled in miles, measurement of energy usage reflects total electricity consumption over a period of time, typically a billing period. There are specific costs incurred by a utility related to a customer's demand (rate of energy use), as well as other costs that relate to a customer's total energy usage. Functionalized costs are typically classified as follows:

Table 2. Classification of Electric Utility System Components.

Cost	Demand	Energy	Customer
Production	**X**	**X**	
Transmission	**X**		
Distribution	**X**		**X**
Customer			**X**

The third step identifying the characteristics of the customer classes and rate schedules, to determine how customers will pay for utility service. Customer classes are developed from loads and load shapes of customers with similar usage characteristics.[2] Traditional COSS have generally identified customers as residential, non-residential or general service, industrial, and lighting. However, it is likely that additional customer classes will need to be established as the availability of AMI data will provide greater clarity into the variety of customers that are interconnected to the electric utility system.

The fourth step, assigning or allocating each cost to jurisdictions and customer classes, determines who pays for certain costs. Some costs are directly assignable to a particular jurisdiction or customer class because they are easily identified with a particular jurisdiction, customer class, or individual customer. Costs that cannot be directly assigned must be allocated based on their function and classification. Such costs are typically allocated using the demand, energy, and customer data determined earlier for the COSS. Costs that have been classified as production or transmission costs are allocated to the jurisdictions and customer classes, at least in part, on the basis of a peak demand factor. Distribution-classified costs are directly assigned to jurisdictions. However, the jurisdictional assignments are allocated to the customer classes based on non-coincident peak demand and the number of customers.

[2] The availability of AMI data is beginning to provide a better understanding of customer usage and load shapes that traditional load research could only estimate. A challenge going forward will be how to utilize new AMI data to determine whether the traditional classification of customers is appropriate for the widening variety of end-users that are presently classified as "residential" and "small general service." Once available, this data should help utilities and regulators to design rates that better reflect cost causation and reduce the potential for cross-subsidy among customer classes.

All costs incurred by the utility must be considered in the COSS, otherwise the utility is not able to reasonably recover its full costs to serve all of its customers. The COSS seeks to ensure that all jurisdictions and customer classes bear appropriate responsibility for the costs they impose upon the system. These cost causation principles serve as the foundation of rate design and should always represent the starting point for the rate designer to calculate and establish rates.

The selection of the methodology or approach to cost-of-service is a critical first step in the development of a COSS. The methodology is often a contentious issue among parties in a general rate case proceeding and has significant bearing on the development of a COSS and the allocation of production and transmission-related costs. The methodology selected dictates the process of calculating demand factors that are used in the allocation of demand-related costs. Some examples include a demand-only method based on the use of a single or multiple coincident peaks, versus a method that employs a weighted method using peak demand and energy to allocate certain costs of production and transmission. While not a subject of this report, the selection of a COSS methodology establishes a framework for the COSS itself and provides guidance on the relationships of demand, energy, and the number of customers that the rate designer will use to set rates for service.

IV. Overview of Rate Design

The general purpose of electric utility rates is to produce revenues for service rendered. The purpose of a specific rate design 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. This report is focused on two principles and objectives that apply primarily to rates and rate schedules for residential and small general service customers, namely the classification of distribution costs as either "demand-related" or "customer-related" and the establishment of a basic customer charge that fairly and reasonably recovers costs.

The COSS informs rate design. The first step following the development of the COSS involves the determination of jurisdictional and customer class returns on rate base and associated revenue requirements. The second step involves the determination of demand, energy, and customer related components by jurisdiction and customer class. In addition, an understanding of the relationships of fixed versus variable costs, and marginal versus average costs, among others, is critical to ensuring that individual rate elements (e.g., basic customer charge, demand charge, energy charge, etc.) within a particular rate schedule are maintained as close to cost causation as possible.

For example, as a general rule, energy costs (costs measured on a per kWh basis) are recovered based on total energy (kWh) consumption. These costs typically consist of the cost of fuel consumed in electric generating plants, as well as other fuel-related (e.g., reagents) or energy-related (e.g., variable operating and maintenance costs and costs stemming from the production of coal combustion by-products) costs that are the direct result of operating the electric generating plants.

Likewise, demand costs (costs measured on a per kW basis) should be recovered based on some measurement of maximum demand (kW) at a particular point in time. Demand-related costs may be incurred and recovered based on a customer's maximum demand placed on the electric utility's entire system (e.g., on the generation units or the transmission system), often referred to as a "coincident peak demand" (CP), or based on demand placed on a more localized part of the electric utility system (e.g., the distribution system), often referred to as a "non-coincident peak demand" (NCP).

For generation and transmission assets, an individual customer's demand is typically measured as their contribution to total demand at the time of the utility's maximum aggregated demand (maximum demand of its customers, both wholesale and retail, at a single point in time). Generating plants and transmission assets are sized to meet a maximum system load, which is diversified and may or may not occur at the same time as the maximum demand of an individual customer of the utility.

For demand-related distribution assets, an individual customer's demand is typically measured as their contribution to the customer class maximum demand regardless of when it occurs relative to the maximum system demand. Some distribution assets are sized to meet a geographically localized maximum demand (e.g., primary conductor wires, distribution substation transformers) while other distribution assets are sized to meet the individual customer's maximum demand (e.g., distribution service transformers). However, distribution costs have both demand-related and fixed characteristics. While distribution related costs must be sized to meet some level of maximum demand, there is also a <u>minimum</u> cost for the distribution system that must be incurred regardless of demand.

In addition to the cost causation principles outlined above, the rate designer is also challenged with navigating different, often conflicting considerations. Those considerations are typically addressed in a general rate case and may include:

- Simplicity of rate designs;
- Rate and revenue stability;
- Migration of customers between rate schedules;
- Recovery of fixed and variable costs;
- Avoidance of rate shock;
- Mitigation of rate shock without exacerbating cross-class subsidies;
- Policy objectives that have been established by statue, rule, or prior Commission order;
- Innovative versus traditional rate designs;
- Appropriate price signals to customers; and
- Encouraging the efficient use of electricity.

The rate designer does not have the luxury of starting with a "clean slate" to meet all of these cost causation principles and other considerations. Many legacy rate schedules maintain rate designs that do not reflect many of today's energy realities.[3] For example, the basic residential rate schedule, which covers 90% of all residential customers, only utilizes two rate elements – a monthly flat basic customer charge and a per kWh energy charge. Any fixed costs not recovered from the flat monthly customer charge must be included in the variable energy charge. This traditional design was implemented for practical reasons, not for cost causation or theoretical rate design reasons. The recovery of fixed and non-energy variable costs through an energy charge leads to cross-subsidization within the residential class of customers. The ease of administering this rate design has been considered an acceptable trade-off until recently.

V. <u>History and Use of the Minimum System Method in Classifying Distribution System Costs</u>

Cost-of-service analysts have traditionally recognized that costs associated with the distribution system exhibit characteristics that are both demand- and customer-related. The most basic, and least controversial, representation of customer-related distribution costs are those associated with facilities closest to the customer's point of delivery (e.g., the meter and service drop wires). However, the meter and service drop wires must be connected to the broader electrical grid in order to deliver energy to a customer. The distribution grid must be designed to be capable of meeting the maximum level of electrical demand placed on it by customer loads. The question then becomes, how much of the distribution grid should be considered demand-related versus how much should be considered customer-related, for cost recovery purposes? Historically, North Carolina's regulated electric utilities have relied on the MSM to answer this question.

The Public Staff reviewed Commission orders to gain an understanding of the history related to COSS and the application of MSM to the electric utilities. Our review focused on orders from the late 1960s and early 1970s, when Commission orders began to include detailed discussion of cost-of-service. At that time, electric utilities were experiencing significant growth in the demand for electric utility service and the need to build capacity to meet those demands, causing significant upward pressure on rates. The orders reflect that the Commission was concerned not only with the need to serve new electric demand, but also the need to balance the increasing costs between new and existing customers, as well as equitably balancing the rates of growth between residential and non-residential customers. While not an exhaustive list (see Appendix 3), the Public Staff notes several Commission orders that provide some foundation for the COSS, recognition that distribution system costs are both demand- and customer-related, and the use of MSM in apportioning distribution system costs. The Commission's June 28, 1973 Order in Docket No. E-22, Sub 141 was the only order found by the Public Staff that provides specific direction for calculating and applying the MSM. Since that time and until recently, the MSM has not been an issue that received prominent attention in Commission proceedings, even though there were numerous general rate cases in the 1970s and 1980s.

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[3] Energy efficiency programs, net metering, enhanced data, smart appliances, etc.

The MSM has also served as a foundation for establishing the flat monthly basic customer charge. Since the early 1970s, electric utilities have supported their requests to increase customer charges on the COSS determination of "customer-related" costs. There is no evidence to suggest utilities have ever requested a monthly customer charge that reflected the total cost per customer that was determined to be "customer-related" via the MSM.[4] In addition, the Public Staff is not aware of any case where it supported, or the Commission granted, a basic customer charge increase to reflect the total amount of costs designated as customer-related in a MSM study.

VI. Methods Used to Classify Distribution Costs

As stated above, there is broad consensus that the distribution system is comprised of equipment that is both demand- and customer-related; however, there is little consensus on the calculation and determination of the portions classified as either demand- or customer-related.[5,6] In order to classify the distribution system components, the utilities use a method that defines the scope and purpose of each component of the distribution system as it relates to demand and customers.

The NARUC Manual dedicates a full chapter on the classification and allocation of distribution plant, including what amounts to the best explanation and description of the two approaches to classifying distribution costs – the minimum-size method or the minimum-intercept method (also called zero-intercept). Another approach, known as "basic customer method" has been discussed in recent general rate cases before the Commission. Each of these approaches is briefly discussed below.

A. Minimum-Size Method

According to the NARUC Manual, the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum load requirements of the utilities' customers.[7] This involves a determination of the minimum sizes of poles, conductors, cables, transformers, and services installed by the utility. An average unit cost for each minimum-size piece of equipment is then determined and used to calculate the total cost for the entire inventory of equipment installed. The total cost of this equipment is then classified as "customer-related" costs. The "demand-related" portion is defined as the difference between the total investment in similar equipment and the customer-related portion.

[4] The most recent rate case for each utility is - Docket Nos. E-2, Subs 1023 and 1142; E-7, Subs 1026 and 1146; and E-22, Subs 479 and 532.

[5] "New Uses for an Old Tool: Using Cost of Service Studies to Design Rates in Today's Electric Utility Service World," P. Morgan and K. Crandall, EQ Research, LLC, April 2017.

[6] P. 29, "Charging for Distribution Utility Services: Issues in Rate Design", December, 2000, Frederick Weston, The Regulatory Assistance Project, (Weston Report).

[7] P. 90, NARUC Manual

B. Minimum-Intercept Method

The minimum-intercept method attempts to identify and quantify the portion of the distribution system that would correspond to a hypothetical “zero-load” or “zero-intercept” situation.[8] The NARUC Manual recognizes that the minimum-intercept method is theoretically the most accurate; however, it requires significant data to calculate. As part of the calculation, a cost curve is developed for existing equipment of various sizes and loads. Regression analysis is then applied to the curve to calculate the point at which the trend line intersects the cost axis. The value at the intersection represents the "zero-load" cost. The "zero-load" cost per unit of equipment is then applied to each quantity of distribution equipment, regardless of size, to determine a total cost of zero-load equipment. The ratio of the zero-load costs to the actual total investment in equipment is determined to be "customer-related". The remainder is considered to be "demand-related."

C. Basic Customer Method

The basic customer method is not included in the NARUC Manual, but was introduced by intervening parties participating in recent general rate cases. The basic customer approach classifies 100% of all poles, wires, and line transformers as "demand-related" costs.[9] All other costs (those related to meters and service connections) are classified as "customer-related."[10,11]

VII. Minimum System Method Calculations Used By North Carolina Electric Utilities

The utilities each have slightly different approaches to calculating the MSM for classifying their respective distribution systems as demand- or customer-related. While all three have adopted a minimum-size approach, the differences cause the individual calculations for each utility to yield different results. The differences include variation in the size of individual pieces of equipment, specific unit costs of that equipment, and the mathematical calculations. The methods used by each utility are discussed below.

A. DEC

DEC describes its approach for FERC Accounts 364, 365, 367 and 368 as a "modified minimum-size method." Instead of using actual, historical embedded costs of distribution plant, DEC estimates the current cost of a minimum system needed to support minimal load, based on assumptions and concepts that are consistent with the NARUC Manual. It then discounts those costs to simulate a vintage of historical embedded cost

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[8] P.92, ibid.
[9] P. 30, Weston Report.
[10] P. 34, ibid.
[11] The Weston Report also makes general reference to substations and substation equipment and indicates that this equipment is all "demand-related." However, the Weston Report is silent on the classification of underground equipment and conduit.

of the minimum system. This simulated value is then multiplied by the total inventory of equipment in each FERC account for the current year. The result is then de-escalated based on the age of the equipment using a Handy-Whitman Index for the average year the equipment was placed in service. A comparison to the current year's value is then made.[12]

As a second step, an index is calculated using the mid-year weighted average age of equipment. The average weighted age is then computed by dividing the sum of the weighted ages by the sum of all vintage costs for the equipment. The resulting weighted average age is then subtracted from the current year. The year calculated is then used to determine the Handy-Whitman average age index value for that year.

The third step involves taking the Handy-Whitman index value for the average age and multiplying it by the current year minimum costs determined in the first step to obtain the average historical cost. This value is then multiplied by the total inventory of equipment to produce a minimum installed cost. This amount represents the customer-related portion of the FERC account balance.[13]

DEC considers 100% of FERC Accounts 366, 369, and 370 to be customer-related; 100% of FERC Accounts 360, 361, and 362 to be demand-related; FERC Account 363 is not applicable to DEC.

B. DEP

The approach used by DEP in its most recent rate cases to estimate the minimum system for FERC Accounts 364, 365, 367, and 368 is slightly different from that used by DEC. DEP has relied on a 2010 study,[14] rather than the method employed by DEC that uses actual plant adjusted based on age. DEP indicated that the results of both the DEC method and DEP method produce comparable results; however, DEP acknowledges that its calculation is more complex and time-consuming than DEC's approach, and since they produce similar results, DEP plans to incorporate the DEC method of calculating the minimum system in future rate cases.

C. DENC

DENC has generally followed a method for calculating the minimum system as established by the Commission's June 28, 1973 Order in Docket No. E-22, Sub 141 (Sub 141 Order). That order prescribed the use of minimum system approach for FERC Accounts 364, 365, 367, and 368. The distribution line portion of FERC Account 360 was to be classified as 100% customer-related, while FERC Account 369 consisted of

[12] The Handy-Whitman Index calculates the cost trends for utility construction.

[13] Based on the explanation found on pages 7 and 9 of the report provided to the Public Staff on November 8, 2018. The same process is calculated for each applicable FERC account balance. There is some variation of this process for FERC Accounts 365, 367, and 368, but the general process is applied to all FERC accounts. A more thorough description is provided in the report itself, which is attached as Appendix 1.

[14] The Public Staff believes this study is a study of distribution system assets.

minimum-sized overhead and underground cable/conductors. The remaining FERC distribution accounts (361, 362, 363, and 366) were not specifically addressed in the Sub 141 Order.

DENC currently uses a MSM based on taking baseline material unit costs and then scaling these unit costs up to the size of the existing distribution system to calculate the customer-related component. More specifically:

- FERC Accounts 360 and 361: Ratios are developed between the overhead and underground components using the delineation of demand-related and customer-related components calculated via minimum-intercept for FERC Accounts 364, 365, 366, and 367. The sum of the customer-related portions of these accounts is used to calculate the percentage of demand-related and customer-related portions of overhead and underground, and primary and secondary account balances, which are then applied to the total balance for Accounts 360 and 361.

- FERC Account 362 and 363: DENC considers 100% of FERC Account 362 to be demand-related; FERC Account 363 is not applicable to DENC.

- FERC Account 364: DENC uses the embedded historical unit cost of a 35-foot pole[15] as determined from Company records. This amount is then multiplied by the total number of poles at primary and secondary levels to determine the customer-related amount for FERC Account 364. The demand-related portion is calculated as the difference between the total balance of FERC Account 364 and the customer-related amount.

- FERC Account 365: DENC uses 4/0 and under wire[16] as the minimum-size component for overhead conductors. The embedded historical unit cost of one pound of 4/0 and under wire is determined from Company records. Using a pounds/foot estimate for the wire, this unit cost is multiplied by the number of wire-feet of conductor in the existing distribution system (at primary and secondary levels) to determine the customer-related portion of FERC Account 365. The demand-related portion is calculated as the difference between the total balance of FERC Account 365 and the customer-related amount.

- FERC Accounts 366 and 367: DENC uses the cost of #4 underground primary cable for primary distribution or #8 secondary cable for secondary distribution as the minimum-size components.[17] Both costs are calculated using regression analysis. The present day unit cost for each size of cable is scaled to an estimated historical cost for the system using a de-escalation factor based on the Handy-Whitman Index. The resulting unit cost for each size of cable is multiplied by the total circuit feet of primary and secondary cable, respectively,

[15] Ordering paragraph 7d in the Sub 141 Order.
[16] Ordering paragraph 7e in the Sub 141 Order.
[17] Ordering paragraph 7f in the Sub 141 Order.

to determine the basis for the customer-related portions of primary and secondary cable. The demand-related portion is calculated as the difference between the total balance of primary and secondary costs, respectively, of FERC Account 367 and the customer-related amounts. The same percentages determined for FERC Account 367 are then applied to FERC Account 366.

- FERC Account 368: DENC uses the cost of a zero-intercept transformer as the minimum system component. This zero-intercept unit cost is multiplied by the total number of transformers to determine the customer-related portion of FERC Account 368. The demand-related portion is calculated as the difference between the total balance of FERC Account 368 and the customer-related amount.

- FERC Account 369: DENC calculates the customer-related portion of this account separately for overhead and underground service drops. The minimum-size component of an overhead service is 80 feet of #2 aluminum service conductor.[18] The present day unit cost for this service is scaled to an estimated historical cost for the system using a de-escalation factor based on the Handy-Whitman Index. The resulting unit cost is multiplied by the total number of overhead customers to determine the customer-related portion. For underground services, DENC uses a #8 service conductor[19] from the pad or pole to the facility (calculated using regression analysis). The present day unit cost for underground service is scaled to an estimated historical cost for the system using a de-escalation factor based on the Handy-Whitman Index. The resulting unit cost is multiplied by the total number of underground customers to determine the customer-related portion. The sum of each customer-related amount (overhead and underground) is subtracted from the total balance of FERC Account 369 to determine the demand-related amount.

- FERC Account 370: DENC considers 100% of FERC Account 370 to be customer-related.

VIII. Public Staff's Policy Objectives for Cost-of-Service and Rate Design

The Public Staff’s objectives regarding cost-of-service and rate design have incorporated the central tenet that the electric utility system is planned, built, and operated on the basis of providing safe and reliable electric utility service at the least reasonable cost possible, while meeting both the capacity and energy needs of the consuming public.

The Public Staff has advocated that cost-of-service should be the foundation of establishing the appropriate apportionment of the revenue requirement. Once the revenue requirement is calculated, it must be apportioned among the customer classes. The process of apportioning the revenue requirement then relies upon the overall

[18] Ordering paragraph 7h in the Sub 141 Order.
[19] Ibid.

jurisdictional return on rate base (ROR) that is calculated for the utility. The Public Staff continues to believe that the apportionment among the classes should accomplish four goals:

- Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;

- Maintain a ±10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;

- Move each customer class toward parity with the overall jurisdictional ROR; and

- Minimize subsidization of customer classes by other customer classes.

IX. Public Staff's Conclusions and Recommendations

The establishment of the proper fixed charge component of electric rates, also called the basic customer charge, has been an issue since the late 1960s and continues today. Parties advocating positions in general rate cases have based their positions on the COSS to support their individual points-of-view. Utilities have frequently advocated basic customer charges that trend more toward the full customer value identified in COSS calculated using the MSM. Other parties have advocated for a method that minimizes the classification of distribution costs that are customer-related.

The Public Staff has traditionally advocated a position that supported a basic customer charge based on the utilities' MSM, while recognizing that full movement would likely result in rate shock for many customers, particularly low-income and low-usage customers.

Trends in utility service that indicate more customer-owned generation is being installed and that those customers are buying less energy from the utilities further exacerbates the fixed cost recovery equity issue, leading to higher energy charges as utility sales diminish. Such a reality will have a significant impact on low-usage and low-income customers if all customers are not equitably participating in the recovery of fixed costs. While sales may decrease, fixed costs will likely not.

As a result of the examination of MSM, the Public Staff believes there are fixed costs of electric service that should be recovered from all customers; however, we acknowledge that there is a debate over the extent to which the costs[20] of electric utility service are fixed. Utilities tend to suggest that a significant portion of the costs incurred to provide utility service is fixed.[21] However, many economists suggest that, over the long-run, most costs are not fixed.[22, 23] This debate is difficult to reconcile because on the one hand, the utility's cost-of-service and the rates charged to recover these costs, are typically the result of a short-term perspective. In other words, utilities collect revenues from rates that remain static only until the next general rate case or rider proceeding. On the other hand, capital investments in utility service are long-lived, and often "lumpy"[24] investments, intended to provide service for 25 or more years.

The Public Staff believes that certain aspects of utility service, and the associated costs, are fixed. Once capital investments are made and the equipment is deemed used and useful for utility service, those costs are incorporated into the utility's revenue requirement calculations and will remain there until fully recovered.

All customers should bear some responsibility for the fixed costs of utility service. Fixed costs are incurred to produce, transmit, distribute, and administer electric utility service and are essential components of that service. Any utility customer interconnected to the utility's transmission and distribution grid for the purpose of receiving electric service should be responsible for some portion of fixed costs. Customers who are able to avoid contributing toward the recovery of fixed costs through the modification of consumption patterns are shifting costs incurred to serve them to other customers and customer classes.

The Public Staff is concerned about the impact of fixed cost recovery on low-income customers. Increases in fixed charges can disproportionately impact low-income and low-usage customers. However, the Public Staff believes that any efforts undertaken by the electric utilities to help low-income customers should be narrowly tailored, rather than setting fixed cost recovery artificially low. Considering any revenue not recovered in the fixed charge is recovered in the energy charge, setting the fixed charge too low results in a disproportionate increase on low-income customers that are also high-usage customers.

After our review, the Public Staff believes[25] that the use of MSM by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for

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[20] The Public Staff considers fixed costs to be those that do not materially change in proportion to the delivery of capacity, energy, or the number of customers.

[21] See responses in Appendix 2.

[22] P.336, "Principles of Public Utility Rates," Public Utilities Reports, Inc., Bonbright, James C., Columbia University Press, New York, 1961.

[23] "Caught in a Fix – The Problem with Fixed Charges for Electricity," Synapse Energy Economics, Inc., February 9, 2016.

[24] An investment's "lumpiness" refers to the fact that it cannot be added in discrete increments to just match incremental demand requirements. Examples are baseload generating plants, substations, and transmission and distribution networks.

[25] The position of the Public Staff in any future rate case is dependent on the application filed in that case. The Public Staff reserves the right to develop a new or different position concerning the MSM in any future proceeding before the Commission.

establishing the maximum amount to be recovered in the fixed or basic customer charge. While not precise, MSM is a logical methodology for classifying costs of a distribution system as demand- or customer-related. However, the Public Staff believes the following principles should also be applied in establishing the fixed charge:

- The minimum amount recovered in the fixed charge for any rate class should be an amount determined by the "basic customer method" which reflects the customer meter, service drop, and any other facilities uniquely attributable to specific customers that are not already recovered through extra facilities charges.[26]

- Any increase in the fixed charge for any rate class should not exceed an amount that would recover more than 25% of the revenue increase that was assigned to that customer class.

The Public Staff also recommends:

- That future cost-of-service studies should be designed to provide a more accurate picture of the fixed costs of utility service, both as an aggregate cost to each customer class, and on a dollar per customer, dollar per kW of demand, and dollar per kWh basis. The Public Staff believes this will begin to provide information on the costs that are truly unavoidable, as well as provide a different perspective of any cross-subsidy issues among the customer classes. The Public Staff also believes this will provide vital information regarding the amount of any basic customer charge or other unavoidable charge that may be established.

- That cost causation principles in cost-of-service studies and rate design should be balanced with efforts to provide relief to low income customers. Any effort to provide relief to qualifying low-income customers should be considered separate from the setting of the general fixed cost recovery in a rate class.

- That utilities utilize data gained from AMI meters to implement rate design changes, including new customer classes, demand charges for all rate classes, and new rate designs.

- That the Commission should request that NARUC, or some other independent entity, undertake a study of these issues from a national perspective, so as to gain insight from best practices and ideas across the country.

[26] Extra Facilities Charges are typically those charges associated with equipment that must be installed at or near the point of delivery due to the unique customer loads.

I. Introduction

In the evidentiary hearings in Docket No. E-7, Sub 1146 In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable for Electric Service in North Carolina, there was considerable testimony and cross-examination of witnesses around Duke Energy's use of the minimum system approach to allocate distribution plant and its basic facilities charge. In its order dated June 22, 2018 in this Docket, the North Carolina Utilities Commission approved Duke Energy Carolina's use of the minimum system concept for cost allocation in that proceeding. The North Carolina Utilities Commission also ordered as follows:

> 38. That the Public Staff shall facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose.

The Public Staff conducted a meeting in its offices on September 11, 2018, and invited representatives of both Duke Energy and Dominion Power to participate. At this meeting, each electric utility presented an overview of its approach to calculating the minimum system. Following these presentations, the Public Staff asked each utility to respond within 60 days to the following questions:

- Overview of current company allocation of distribution costs.
- History of the use of minimum system, including any proceedings and orders where Commission has discussed minimum system for each utility.
- History of allocation of distribution costs as "demand-related" and "customer-related."
- Explain the Company's current allocation of distribution costs and why it is appropriate.
- Whether or not the basic customer method of allocating costs should be adopted.
- Other options for allocating distribution costs as customer or demand-related, and other methods for setting the basic customer charge.

The purpose of this report, therefore, is to provide Duke Energy Carolina's and Duke Energy Progress's ("Duke Energy") response to the Public Staff's information request.

II. Overview of Current Company Allocation of Distribution Costs

The distribution system can be described as that part of the electric system from the primary bus of the general distribution substation that reduces high voltage to a lower level that can be transmitted through the distribution system all the way through to the customer's premises. From an allocation perspective for minimum system purposes, however, the distribution system consists of (1) primary lines and poles that distribute the power (2) distribution transformers which reduce the voltage from a distribution voltage to a voltage capable of operating customer equipment and (3) secondary lines and services to deliver electricity to the customer's premises. The general distribution substation is installed and located primarily to meet customer demand and therefore doesn't have a customer component.

Distribution systems are designed primarily to support connection to individual customer sites and are sized with sufficient capacity to meet customer demand. That is, they are built to serve a single customer or group of customers based on anticipated demand in the general location of the facilities. In addition, transformers, poles and wires are needed to connect to each individual customer in a specific area. Lastly, facilities must be sized to allow the customer to receive sufficient energy to meet their own power needs but also the power needs of all customers served from the circuit. Duke Energy has therefore concluded that the distribution system is constructed primarily to connect to individual customers but also must have sufficient capacity to serve the collective load on the circuit. Therefore, the allocation of distribution plant has both a clear customer and demand component.

The table below is excerpted from a Duke Energy Carolina's (DEC) cost of service study. It demonstrates that distribution plant-in-service for FERC Account 364 – Overhead Poles, Towers & Fixtures not directly assigned to a customer class is allocated across all customer classes using non-coincident demand and customer allocation factors. Note also that this account has been further subdivided between primary and secondary plant to ensure that customers served at the higher primary voltage level are not assigned costs for the secondary system that does not serve them. Lastly, this account also includes two components that are labeled "MIN SYS" or minimum system. A discussion of how these minimum system dollar amounts are derived is contained in a later section of this report.

Account	Jurisdictional Allocator	Customer Class Allocator
364 DISTR PLANT-POLES-EXTRA FAC	Direct Assign	Direct Assign
364 DISTR PLANT-POLES-PRI CUST-MIN SYS-NCR	Direct Assign	All - Cust Num Pri x OL
364 DISTR PLANT-POLES-PRIMARY DMND-NCR	Direct Assign	All - NCP Pri
364 DISTR PLANT-POLES-SEC CUST-MIN SYS-NCR	Direct Assign	All - Cust Num Sec x OL
364 DISTR PLANT-POLES-SECONDARY DMND-NCR	Direct Assign	All - NCP Sec

This same basic approach is used for all the distribution plant accounts from FERC Account 364 through FERC Account 368.

III. History of the use of minimum system, including any proceedings and orders where Commission has discussed minimum system for each utility.

In its order dated June 21, 1973 in DOCKET NO. E-7, SUB 145 In the Matter of Application of Duke Power Company for Adjustment of Rates and Charges Applicable for Electric Service in North Carolina, the North Carolina Utilities Commission stated:

> The commission staff made a full and complete investigation of the 1971 cost-of-service study. Staff Witness Clapp testified on the manner of execution of Duke's 1971 study and made recommendations for changes in future studies. The use of the minimum-intercept method of calculating certain of the consumer components of distribution costs was recommended by the staff in order to refine the accuracy of the study and produce more stable and comparable results over time. Mr. Clapp testified that the Duke cost-of-service study followed some of the methods which are outlined in a forthcoming NARUC publication on the subject, that the staff had examined the treatment of each account in the study as to the appropriateness of its use, that only two accounts required adjustment and that, overall, the Duke Study did not require adjustment. Staff revised the 1971 cost-of-service study to reflect the use of statistical regression techniques and the minimum-intercept method in the allocation of poles (on the basis of average height, average year, and Class 7 size intercept) and transformers (a zero-load intercept). The recommendations made by the staff, and the revision of that 1971 cost-of-service study to conform to the staff recommendations were not challenged.

Under a Finding of Fact, the North Carolina Utilities Commission found that:

> 22. That the use of the minimum intercept method of calculating customer components of distribution plant produces more correct and more stable and comparable results over time than the minimum-size method.

In its order dated June 28, 1973 in DOCKET NO. E-7, SUB 141 In the Matter of Application of Virginia Electric and Power Company for Authority to Increase Its Electric Rates and Charges, the North Carolina Utilities Commission found that:

> (7) That VEPCO shall complete and file with the Commission annually on April 30 a Cost of Service Study detailing the rate of return earned by each class of service, and the customer, demand and energy components of revenue deductions and net plant investment, and allowance for working capital; that such studies shall be based upon each calendar year's operations; that demand data used shall have been taken within two years of the end of the period under study; that the methods of execution of cost of service studies shall be determined by the Company with the goals of accuracy, responsible allocation, and stability over time; and that studies based upon alternative methods may be submitted for consideration, but that at least one shall be based upon the following:
>
> (a) Sizes of distribution plant used in computation of customer components shall be the minimum sizes which will meet the requirements of the National Electrical Safety Code and other like restrictions, and costs for such sizes of equipment shall be actual costs, if available, or shall be computed using statistical regression techniques and the minimum-intercept method.
>
> (b) Coincident demands shall be measured at the time of daily system peaks, and that demand data taken at the time of the top five daily system peaks (if all five are within 1/2% of the yearly system peak) shall be averaged to calculate the coincident demand factors to assure proper assignment of `coincident peak responsibility.
>
> (c) -The distribution line portion of Account 360, Land and Land Rights, shall be allocated on customers only.
>
> (d) Account 364 - Poles, Towers, and Fixtures, shall be allocated to primary and secondary based upon the number of wires on each pole in the sample, weighted by the relative difference in wire sizes, and all neutrals shall be allocated to the primary, that if poles are initially installed oversized to carry planned later wire additions, the final design shall, if possible, be used in the above allocation, and that the Minimum Intercept cost of a Class 7 pole shall be used when computing the customer component.
>
> (e) The calculation of the customer component of Account 365 - Conductors, shall be based upon two-wire secondaries and primaries and three-wire joint secondary\primary lines, and that the Minimum Intercept cost of #4 ACSR or equivalent shall be used.
>
> (f) The calculation. of the customer component of Account 367 - Underground Conductors and Devices, shall be based upon #4 Al UG cable primary and #10 Cu or #8 AI duplex 600 V UG cable (or such cable as to carry a minimum load). for secondaries.
>
> (g) The calculation of the customer component of Account 368 - Transformers, shall be based upon a 0 KVA Minimum Intercept.
>
> (h) The calculation of the customer component of Account 369 - Services, shall be based upon #4 EC, #ACSR,#I0 AD Cu., or #12 MHO Cu for overhead services and #I0 Cu or #8 AI duplex 600 volt UG cable for underground.

In its Order dated August 5, 1988 in DOCKET NO. E-2. SUB 537, In the Matter of Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Rates and Charges on page 130 the North Carolina Utilities Commission stated that:

> In this proceeding, the Company proposed to discontinue the use of its minimum system technique for allocating a portion of distribution plant between customer classes. CIGFUR-II, the Department of Defense, and the Public Staff recommended that the minimum system technique be retained. The minimum system technique derives the cost of distribution plant as if all components of such plant are "minimum" size (i.e., the minimum size needed to connect each customer to the system regardless of the amount of kWh used). The cost of the "minimum" distribution plant is then allocated between customer classes on a per customer basis, while the remainder of the distribution plant cost is allocated between customers on the basis of distribution level kW demand. The Company contended that it is more appropriate to allocate the investment in meters and services on a per customer basis and the remainder of the distribution system on a per kW demand basis. However, such reflection of minimum distribution plant costs in the basic customer charges would result in residential customer charges at least double the current $6.75 per month. The Commission has never approved residential customer charges approaching the levels indicated by the minimum system technique.
>
> The Commission is of the opinion that the minimum system technique should not be discontinued at this time. The minimum system technique allocates more of the distribution plant to residential customers and less to large industrial customers. It is conceptually sound even if the results are not fully reflected in the basic customer charges. Furthermore, retention of the minimum system technique will modify somewhat the impact of the SWPA allocation methodology on the industrial class.

In this order, in its Findings of Fact, the Commission found:

> 14. The Summer/Winter Peak and Average method, Including the minimum system technique, is the most appropriate method for allocating costs between jurisdictions and between customer classes within the North Carolina retail jurisdiction in this proceeding. Consequently, each finding in this Order which deals with the overall level of rate base, revenues, and expenses for North Carolina retail service has been determined based upon the summer/winter peak and average cost allocation methodology as described herein, including the minimum system technique.

In DOCKET NO. E-2. SUB 1023, In the Matter of Application by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Progress Energy Carolinas, Inc. (PEC) asked to be relieved of the obligation to file 12-month average coincident peak cost allocation studies and summer/winter peak and average cost allocation studies excluding the minimum system technique. In its Order dated September 25, 2012, it was ordered:

> Based upon PEC's Motion and the record in this docket, the Chairman is of the opinion that good cause exists to relieve PEC of the obligation of filing cost allocation studies using the summer/winter peak and average excluding the minimum system technique, the 12 CP including the minimum system technique and the 12 CP excluding the minimum system technique.

Thus, PEC was required to continue to file cost allocation studies that included the minimum system technique.

Therefore, since 1973, electric utilities serving North Carolina have filed and the North Carolina Utilities Commission has consistently recognized and approved an allocation of a portion of poles, lines and transformers within distribution plant with a customer-related component based on a minimum size concept.

IV. History of allocation of distribution costs as "demand-related" and "customer-related."

As stated earlier, distribution facilities are designed primarily to deliver electricity to each individual customer but also have the capacity to meet the combined local area loads. One could view a distribution system as a network that radiates outward carrying power to each customer. with ever smaller wires and transformers carrying power to the customer. These distribution networks must be designed to meet their area's maximum peak demand; but as you go further from the substation, lower capacity lines are required since these lines serve fewer customers near the end of circuits. Each component of the distribution system must be designed to meet the maximum anticipated demand of the components "downstream" from it. Due to load diversity, the peak requirement of each individual customer's peak is unlikely to coincide; therefore, the Company must consider both the combined coincidental load on the circuit as well as each customer's individual peak in sizing facilities. This consideration is especially true with distribution facilities close to the customer site such as transformation and secondary circuits which must have sufficient capacity to serve the customer's maximum load in all hours. This diversity of loads is also true with respect to distribution primary capacity since individual circuits don't always experience their highest peak coincident with the system peak for generation and transmission assets. Thus, it is appropriate to allocate distribution plant that is sized to meet demand requirements with a non-coincident peak allocation factor.

Customer-related costs are those that vary based on the number of customers connected to the system. The cost of meters, billing and the customer's service drop are typically accepted by Commissions as customer-related costs since these costs are only incurred to meet an individual customer's electrical needs. Some jurisdictions advocate that the customer charge, a fixed, monthly charge that the customer pays regardless of their usage level, should only include these costs, but this ignores the fact that the basic distribution infrastructure is constructed solely to provide customer connections to the grid.

In the NARUC Cost Allocation Manual, there are two primary methods used to calculate customer-related distribution costs. The first is the "minimum-size" method. This theoretical approach assumes there is a minimum-size distribution system that can be determined to serve a customer's minimum load; such as, one 100-watt light bulb. Once the cost of this minimum system is determined, all costs above this amount are allocated using a demand allocation factor.

The second method is the "zero-intercept" method. This approach attempts to determine the minimum system necessary to provide the customer access to the system without providing any level of demand. Thus, if no demand can be provided, it follows that this portion of the distribution system cannot be demand related. Again, all distribution costs above this minimum amount are allocated using a demand allocation factor. While perhaps theoretically attractive, this method is computationally complex as it requires statistically regressing the installed costs against various sizes of distribution equipment to determine the zero or no-load intercept.

V. Explain the Company's current allocation of distribution costs and why it is appropriate

Section II of this report describes the basic approach Duke Energy uses in allocating distribution plant costs. However, Section II does not describe in detail how Duke Energy computes the minimum system component of distribution plant costs.

Duke Energy uses a modified minimum-size method. Instead of using the historical embedded cost of distribution plant, which is not readily available, Duke Energy Carolinas estimates the current cost in current year dollars of distribution plant for a minimum system (designed to support minimal usage) based on assumptions and concepts consistent with the NARUC method of minimum system and then "de-escalates" it to simulate a vintage "historical embedded" cost of this minimum system. The table below provides an example of the 2017 Costs Per Mile of Skeleton Plant for Account 364 – Overhead Poles, Towers & Fixtures for Duke Energy Carolina, LLC (DEC) developed by distribution engineering:

Description	CU	Quantity	Labor	Total Labor	Material	Total Mat
40/5 poles	POLE-WD-40-C5-C	23	641.59	14,756.57	153.40	3,528.17
Primary Guy	GND-POLE-6-C	14	44.90	628.67	10.92	152.83
	ANCH-PISA-SM-C	14	159.32	2,230.52	29.50	412.94
	GUY-DOWN-3/8IN-GALV-SGL-C	14	105.87	1,482.12	35.08	491.07
	GUY-HOOK-C	14	0.00	0.00	6.89	96.48
	GUY-INSL-7FT-FG-C	14	48.12	673.75	13.69	191.65
	HDWR-MACH-LG-12IN-GALV-C	14	0.00	0.00	1.93	27.03
Extra Guy	GUY-DOWN-3/8IN-GALV-SGL-C	14	105.87	1,482.12	35.08	491.07
	GUY-HOOK-C	14	0.00	0.00	6.89	96.48
	HDWR-MACH-LG-12IN-GALV-C	14	0.00	0.00	1.93	27.03
				$21,253.74		$5,514.74
	Total Costs					$26,768.48

This 2017 value of $26,768 per mile is multiplied by the number of miles of overhead line to estimate the overhead line plant balance in FERC account 364 for a minimum system built in 2017. Subsequently, this 2017 plant balance is de-escalated to the weighted average year that plant balance was placed in-service, in order to estimate the minimum system portion of the embedded vintage plant in Account 364. DEC de-escalates this plant balance by employing the Handy-Whitman Index of Public Utility Construction Costs - Section E2 - Cost Trends of Electric Utility Construction - South Atlantic Region for Total Distribution Plant for the average year the plant in FERC Account 364 was placed in-service versus the same index as of 2017.

For DEC's Account 364, the 2017 index is 674. The second index is more involved in that it requires the determination of the weighted average age of the Account 364 assets. As shown in the table below, the age of each vintage is determined by subtracting the vintage year from the base year of 2017 and adding 0.5. to produce a mid-year result. The weighted age is calculated by multiplying each vintage's cost by its age. The average weighted age is then computed by dividing the sum of the weighted ages by the sum of all the vintage costs which results in 18.86 years for Account 364 - Overhead Poles, Towers & Fixtures. The table below summarizes this calculation for selected years since the complete table for all years would contain excessive detail.

Vintage	Cost	Age (2017 - vintage) + .5	Weighting cost x age
1960	4,940,355.15	57.5	284,070,421.13
1961	555,612.78	56.5	31,392,122.07
1962	1,096,448.21	55.5	60,852,875.66
2015	53,743,199.35	2.5	134,357,998.38
2016	59,784,449.03	1.5	89,676,673.55
2017	89,455,592.70	0.5	44,727,796.35
Total	1,312,791,934		24,756,778,615.15
Average Age			18.86

The resulting weighted average age of 18.86 years is then rounded to 19 years and subtracted from 2017 to produce the date of July 1, 1998. Using this date in the Handy-Whitman index results in an average age index value of 298. Multiplying the 2017 Account 364 minimum cost per mile, $26,768, by the "de-escalation" factor, 298/674, results in a weighted average historical cost of $11,835 per mile. In turn, this value is multiplied by the miles of overhead lines, 48,998, to produce a minimum installed cost for Account 364 of $579,893,159.

With some variations, this process is repeated for FERC Accounts 365, 367 and 368. For example, Account 367 - Underground Conductors & Devices the miles of line value includes only underground lines. For Account 368 – Line Transformers, the miles of line value represents only primary lines as line transformers are not needed on secondary lines. In contrast, Account 366 – Underground Conduit is treated 100% as minimum system as underground conduit is not installed based on demand but rather by customer location. The attached Exhibit A provides a more detailed summary of DEC's minimum system calculation for all the relevant distribution-related FERC accounts.

In the cost-of-service study, the minimum system portion of these distribution accounts are allocated to customer classes based on the number of customers. The remainder of these accounts, less any direct assignments, are allocated using a non-coincident demand allocator.

While Duke Energy Progress(DEP) employed a slightly different approach to estimating the minimum system portion of its vintage distribution plant balances in FERC Accounts 364, 365, 367 and 368 in its most recent cost-of-service filings based on a historic 2010 study, it achieved a comparable result to the methodology described above. Since it is a less complex calculation, DEP plans to follow a similar approach to estimating minimum system costs in future cost-of-service studies as described above.

VI. Whether or not the basic customer method of allocating costs should be adopted

The "basic customer" method classifies service-drops, meters, meter-reading and billing as customer-related costs while poles, wires and transformers are classified as demand-related. This concept's premise is that metering and billing costs do not vary based on usage or demand and thus are rightfully recovered in the monthly recurring charge. However, this approach does not recognize the utility's requirement to provide a basic amount of distribution facilities, including poles, line and transformers, to provide service to a customer with, say, just one 100-watt light bulb.

The “basic customer” method is, therefore, inconsistent with cost causation principles which are the bedrock of cost-of-service studies and ratemaking.

The “basic customer” approach promotes cross-subsidies among customers. For a residential class of customers with a fixed customer charge designed only to collect metering, billing and customer service costs, low usage customers will not be covering all the costs of the distribution system installed to connect and serve them. Thus, high usage customers will subsidize low usage customers through their bills. If the minimum system concept is employed, some of the distribution costs are recovered in the customer charge thereby lowering the remaining portion of the rate and reducing the subsidy.

This cross-subsidization is further aggravated because the majority of residential customers’ rates do not have a demand component, collecting all non-fixed costs through an energy rate. Duke is not aware of anyone that advocates that the Distribution system costs are driven by kwh usage or energy. The basic customer approach argues that more of the distribution costs should be functionalized as demand related vs. customer related. However, neither DEP or DEC currently has demand charges in its primary residential rate schedule. As a result, the demand related charges are often recovered through an energy rate. This leads to additional cross-subsidization.

VII. Other options for allocating distribution costs as customer or demand-related, and other methods for setting the basic customer charge.

As described above, Duke Energy allocates distribution plant using number of customers and non-coincident demand allocators. There is an allocation method that allocates distribution plant using a weighted average of the non-coincident demand and the Individual Customer Maximum Demand(ICMD). ICMD is the total maximum demand of the individual customers in a specific distribution locale. Duke’s position is that all customers do not impose their maximum demand on the distribution system at the same time. Rather, individual customers will use their maximum demand at different times than other customers who are served by the same distribution facilities, and as a group, will have a non-coincident peak that is less than the group's ICMD. (For obvious reasons, this load diversity is higher the farther away the distribution equipment is from the customer.) Thus, Duke Energy "sizes" distribution equipment to meet this non-coincident peak.

One could argue that distribution costs are largely fixed and do not vary with load and therefore should entirely be included in the monthly customer charge. These arguments have been accepted in California and Nevada resulting in higher customer charges than seen in North Carolina.

A utility in New York filed a cost-of-service study that advocated distribution costs allocated 50% demand and 50% number of customers. This proposal was supported by the Commission staff in that state.

Other jurisdictions, such as Maine, have a basic customer charge which gives the customer up to 100 kWh of "free" energy in a month. It is interesting that Maine rejects the minimum system concept but permits a minimum amount of energy to be included with the customer charge regardless of customer usage.

VIII. Recommendation of Duke Energy in support of Minimum System Concept

Duke Energy believes that "cost causation" is the foundation of cost-of-service studies. To that end, every customer requires some minimum amount of distribution facilities (wires, poles, transformers, etc.) to "access" the distribution system; and thus, every customer "causes" Duke Energy to install some basic amount of distribution equipment. The methodology Duke Energy uses to develop its minimum system is to determine what distribution facilities are required if customers require only some minimum level of usage, that is, a 100-watt light bulb. This minimum level of facilities ensures that electricity can be delivered to each customer when the customer chooses to use electricity. Without the use of the minimum system allocation methodology, low usage customers avoid paying for the distribution facilities necessary to provide service to them which is counter to cost causation principles.

Duke Energy firmly supports the use of the minimum system concept using the modified “minimum size” approach instead of the “zero intercept” method. While theoretically attractive, Duke Energy believes the “zero intercept” method requires more data and is computationally more complex while ultimately achieving a comparable result. Thus, Duke Energy believes the simpler modified “minimum size” method is the preferable approach for setting rates.

DUKE ENERGY CAROLINAS **Exhibit A**

MINIMUM SYSTEM - PROPOSED METHODOLOGY

Minimum Cost per Unit
12 Months Ended December 31, 2017

	2017 Min Cost per Mile of Line (1)	Average Age(Yrs) (2)	2017 Index (3)	Index for Avg age (4)	Adjusted Min Cost per Mile of Line (5)=(1)*(4)/(3)	Miles of Line (6)	Installed Minimum Cost $/Unit (7)=(5)	Installed Minimum Cost Amount ($) (8)=(6)x(7)	2017 NC Plant Bal $000 (9)	NC Direct Assign (10)	Net (11)=(9)-(10)	Min Sys As % of NC Balance (12)=(8)/1000/(11)
Account 364 - OH Poles, Towers, & Fixtures												
	26,768	18.86	674	298	11,835.11	48,997.70	11,835.11	579,893,159	1,124,607	104,076	1,020,531	56.8%
Account 365 - OH Conductors & Devices												
	34,197	15.19	674	322	16,337.44	48,997.70	16,337.44	800,496,943	1,568,968	38,352	1,530,616	52.3%
Account 366 - Underground Conduit												
All minimun system after excluding directs								149,656,000	155,699	6,043	149,656	100.0%
Account 367 - Underground Conduit & Devices												
	34,792	16.01	674	313	16,157.03	29,415.40	16,157.03	475,265,563	1,480,378	62,280	1,418,098	33.5%
Account 368 - Line Transformers												
	13,839	18.24	674	297	6,098.27	57,814.89	6,098.27	352,570,767	1,029,210	43,095	986,115	35.8%

NC	Overhead	Underground
Primary	38,013.27	19,801.62
Secondary	10,984.43	9,613.78
	48,997.70	29,415.40

Notes: (1) This exact approach was not used in the last DEC NC rate case nor in the 2017 NC DEC COSS. At that time, DEC did not offer underground service as a standard service. Thus, underground lines were treated the same as overhead lines for purposes of the minimum system calculation.

Sources:

(1) 2017 Costs Per Mile of Skeleton Plant - includes labor and materials
(2) Sum of each vintage cost times age in years for account divided by sum of all vintage costs for account
(3) Handy-Whitman Index of Public Utility Construction Costs - Section E2 - Cost Trends of Electric Utility Construction - South Atlantic Region for 2017 for Total Distribution Plant
(4) Handy-Whitman Index of Public Utility Construction Costs - Section E2 - Cost Trends of Electric Utility Construction - South Atlantic Region for 2017 for Total Distribution Plant
Acct 364 - 19 yrs July 1, 1998
Acct 365 - 15 yrs July 1, 2002
Acct 367 - 16 yrs July 1, 2001
Acct 368 - 18 yrs July 1, 1999
(6) DEC Line Mileage by State and Phase for Year End 2017

North Carolina Distribution Model Responses for NCUC Public Staff-11/29/2018

1. **Overview and Explanation of Current Methodology:** Dominion Energy North Carolina (DENC) currently employs a minimum-system distribution model to separate the customer and demand components of the electric distribution plant used in providing service to customers. This method is based on applying baseline material unit cost metrics and scaling these unit costs up to the size of the existing distribution system to calculate a minimum system component. Primary and secondary distribution plant assets are separated based on a combination of studies and sampling techniques to arrive at a percentage split between the two categories. Brief summaries are provided below:

    a. FERC Account 360 and 361: These accounts are ratioed between customer and demand, and between overhead and underground, on the basis of the customer and demand plant amounts for Accounts 364, 365, 366, and 367 (whose calculations are described below). Accounts 364 and 365 are overhead, and accounts 366 and 367 are underground. The percentages are then applied to the total balance for each account to arrive at customer overhead, customer underground, demand overhead, and demand underground amounts for FERC 360 and 361.
    b. FERC Account 364: The minimum system component for FERC Acct 364 is considered to be a 35' pole. The embedded historical unit cost of a 35' pole is calculated from existing mass item records. This per unit cost is then multiplied by the total number of existing poles, at primary level and secondary level, to arrive at the minimum system, or customer, portion of FERC Acct 364. The demand amount is computed as the customer amount subtracted from the account total.
    c. FERC Account 365: The minimum system component for FERC Acct 365 is considered to be 4/0 and under wire. The embedded historical unit cost of a pound of 4/0 and under wire is calculated. Using a pounds per foot estimate, this unit cost is then multiplied by the number of wire feet of conductor in the existing distribution system, at primary level and secondary level, to arrive at the minimum system, or customer, portion of FERC Acct 365. The demand amount is derived by subtracting the customer amount from the account total.
    d. FERC Accounts 366 and 367: The minimum system component for Account 367 is the cost of a #4 Primary Cable (for primary distribution) or a #8 Secondary Cable (for secondary distribution). Both prices are calculated via regression analysis. The present day unit cost of each type of cable is scaled to an estimated historical unit cost for the system using a reduction factor based on Handy-Whitman based survivor information. This unit cost is then multiplied by

primary circuit feet and secondary circuit feet respectively. The resulting values then form the respective basis customer amounts for primary and secondary booked cost of cable. These figures are subtracted from the primary and secondary subtotals of the booked cost of cable to arrive at the primary and secondary demand portion of FERC 367. The percentages derived in FERC 367 calculations are then applied to the FERC 366 Underground Conduit account.

e. <u>FERC Account 368:</u> The minimum system component is valued as the average cost of the transformer zero intercept. This unit cost is multiplied by the total number of transformers to arrive at the minimum system, or customer, portion of the account. The customer amount is then subtracted from the total booked cost of line transformers to arrive at the demand amount.

f. <u>FERC Account 369:</u> FERC Account 369 is calculated separately for overhead and underground service drops. The minimum system component for overhead service an 80 foot #2 aluminum service. The present day cost of this service is scaled to an estimated historical unit cost using a reduction factor based on Handy-Whitman based survivor information. This unit cost is multiplied by the total number of overhead customers to arrive at the minimum system, or customer, portion of the account. The minimum system component for underground service is a #8 service, from the pad to facility and from the pole to facility, each calculated via regression analysis. These present day unit costs are scaled to an estimated historical unit cost using a reduction factor based on Handy-Whitman based survivor information. These unit costs are multiplied by the total numbers of underground customers receiving service either from pad to facility or pole to facility to arrive at the minimum system, or customer, portion of the account. The customer amount is then subtracted from the total account to arrive at the demand amount.

g. <u>FERC Account 370-373:</u> These accounts are being classified as customer related. FERC account 370 is assigned as much as possible to each individual customer and the remainder of 370 metering charges is allocated based on the factors relevant to each class. FERC 373 is unique and represents the cost allocated by unit numbers of street lights.

2. **<u>History of the Use of Minimum-System</u>:** The minimum-system distribution plant cost allocation has been used by DENC since the June 28, 1973 Docket No. E-7, SUB 141 order was promulgated by the Commission. This order specified a detailed minimum-size, minimum-system methodology as follows:

> *(7) That VEPCO shall complete and file with the Commission annually on April 30 a Cost of Service Study detailing the rate of return earned by each class of service,*

and the customer, demand and energy components of revenue deductions and net plant investment, and allowance for working capital; that such studies shall be based upon each calendar year's operations; that demand data used shall have been taken within two years of the end of the period under study; that the methods of execution of cost of service studies shall be determined by the Company with the goals of accuracy, responsible allocation, and stability over time; and that studies based upon alternative methods may be submitted for consideration, but that at least one shall be based upon the following:

i. *(a) Sizes of distribution plant used in computation of customer components shall be the minimum sizes which will meet the requirements of the National Electrical Safety Code and other like restrictions, and costs for such sizes of equipment shall be actual costs, if available, or shall be computed using statistical regression techniques and the minimum-intercept method.*
ii. *(b) Coincident demands shall be measured at the time of daily system peaks, and that demand data taken at the time of the top five daily system peaks (if all five are within 1/2% of the yearly system peak) shall be averaged to calculate the coincident demand factors to assure proper assignment of coincident peak responsibility.*
iii. *(c) The distribution line portion of Account 360, Land and Land Rights, shall be allocated on customers only.*
iv. *(d) Account 364 - Poles, Towers, and Fixtures, shall be allocated to primary and secondary based upon the number of wires on each pole in the sample, weighted by the relative difference in wire sizes, and all neutrals shall be allocated to the primary, that if poles are initially installed oversized to carry planned later wire additions, the final design shall, if possible, be used in the above allocation, and that the Minimum Intercept cost of a Class 7 pole shall be used when computing the customer component.*
v. *(e) The calculation of the customer component of Account 365 - Conductors, shall be based upon two-wire secondaries and primaries and three-wire joint secondary\primary lines, and that the Minimum Intercept cost of #4 ACSR or equivalent shall be used.*
vi. *(f) The calculation. of the customer component of Account 367 - Underground Conductors and Devices, shall be based upon #4 Al UG cable primary and #10 Cu or #8 AI duplex 600 V UG cable (or such cable as to carry a minimum load) for secondaries.*
vii. *(g) The calculation of the customer component of Account 368 - Transformers, shall be based upon a 0 KVA Minimum Intercept.*

viii. *(h) The calculation of the customer component of Account 369 - Services, shall be based upon #4 EC, #ACSR, #I0 AD Cu., or #12 MHO Cu for overhead services and #I0 Cu or #8 AI duplex 600 volt UG cable for underground.*

This methodology has been utilized with some deviation from the exact materials but conforming to the general principle and method to present date by DENC. The current undertaking provides an ideal opportunity to revisit and refine the process.

3. **<u>History of Allocation of Distribution Costs as "demand-related" and "customer-related"</u>:** The history of allocation of these components is described above in detail and is currently implemented as ordered by previous Commission rulings.

4. **<u>Explain the Company's current allocation of distribution costs and why it is appropriate</u>:** The Company develops a set of factors to allocate customer-related costs and demand-related costs to the relevant customer classes. These factors are derived based on number of customers in each class at each service level, non-coincident demands, and class peak demands in each class at each service level respectively. The amounts derived in the distribution model are multiplied by the factors for each class and account to arrive at the class amount for that item.

5. **<u>Whether or not the Basic Customer Method of Allocating Costs Be Adopted</u>:** The Basic Customer Method has not been specifically defined by the Public Staff; however, DENC understands this method to mean treating as customer costs all costs for distribution equipment installed directly on customer premises (meaning FERC Accounts 369 – Services, 370 – Metering, 371 – Installations on Customer Premises, and 373 – Street and Traffic Signals). Other distribution FERC accounts (360 – Land, 361 – Structures, 362 – Substations, 363 – Storage Battery Equipment, 364 – Poles, 365 – Overhead Conductors and Devices, 366 – Underground Conduit, 367 – Underground Conductors and Devices, and 368 – Transformers) would then be treated as demand related components.

   DENC does not advocate adopting the Basic Customer method. DENC has concerns regarding two major aspects of the Basic Customer method. The first concern is that, in theory, such a methodology does not appear to accurately reflect the design and use of the distribution system. As DENC understands it, the Basic Customer method argues that only a service and metering are necessary to set up a new customer; any poles and conductors, as well as transformers and substations, are only necessary if that customer were to take electric service (have some level of demand). Yet, by the same logic that conductors, poles, and transformers are unnecessary until demand exists, a meter and a service would be equally unnecessary, as the Company would have no need to meter if there was no electricity being provided, nor would a service drop serve any point if it were not connected to the distribution system. Furthermore, there is an element of demand cost even in Services and Metering, since a larger meter and larger service hookup would likely be needed for a customer expected to have a high demand, compared to a customer that would have low demand/usage. Thus, there does not seem to be a pure distinction between the two in terms of Customer and Demand function.

The Basic Customer method could also be interpreted as distinguishing between facilities solely installed to serve the single customer as opposed to facilities that are shared, but again, there is not such a clear distinction between the accounts as the Basic Customer method supposes. While most distribution poles, conductors, and transformers may be serving multiple customers, there are undoubtedly some locations within the distribution system where a single customer is the only one using certain poles, conductors, and transformers. For example, a relatively isolated rural residential customer at the end of the line may require multiple poles and additional feet of conductor to receive service on their property. As another example, a larger industrial customer might have its own transformer installed and could even have its own substation. Even a first customer in a new shopping development or residential neighborhood would require these "shared facilities" to be installed. While perhaps the sizing of the poles, conductors, and transformers that are installed may vary depending on the anticipated overall demand for the neighborhood or the development, the existence of a single customer requires the installation of poles, conductors, and transformers. Thus, while there is certainly a demand component to those items, the fact that they are shared facilities does not negate that the existence of a single customer requires the install of these facilities, regardless of whether other customers exist to share the facilities.

Furthermore, the concept of shared facilities must necessarily be limited by other factors, such as geography. The nature of distribution facilities is such that they serve much more localized areas than a generation plant or even transmission line, and as such, new customers in a new area would require additional facilities, even if such customers don't add enough demand to the overall system to strain the overall demand capacity of the distribution system. Thus, there is not just a pure demand element to these facilities; there are other considerations and requirements of the distribution system that extend beyond merely satisfying the total demand.

The second objection to the Basic Customer method is that the method is somewhat detached from the relevant ratemaking process. In cost based ratemaking, there are three general types of costs: fixed cost necessary to provide service to the customer, fixed cost necessary to serve the demand of the system, and variable costs dependent on energy. The first (customer costs) are not at all variable. The second (demand costs) are variable over a longer period of time but are fixed in the short term. And the third (energy costs) are variable in the short term as well as long term. With regards to the distribution system, the majority of costs are either customer or demand (there are some energy related costs related to efficient system design and limitation of line losses, as noted in the 1992 NARUC manual). In order to design accurate and appropriate rates based on cost causation, the rates should match the type of cost causation; fixed customer costs should be recovered through a fixed monthly customer charge, demand related costs should be recovered through a peak demand charge, and energy costs should be recovered through an energy related charge. Due to the limitations of current metering plant, most residential and small commercial customers do not have meters that can provide accurate kW demand readings, so a demand charge for residential customers is not currently feasible. Thus, the issue becomes whether it is more appropriate to recover the demand charges through a fixed monthly charge or through an energy charge.

DENC argues that a fixed monthly charge is more appropriate for two reasons. First, as demonstrated above, there are some aspects of distribution plant that are comingled between customer and demand to the point of being inseparable. As these costs cannot be clearly separated between demand and customer, and because a demand charge is not currently feasible, DENC argues that a customer charge is better reflects the costs incurred. Second, DENC notes that there are a number of situations where, if an energy based charge were implemented, a customer may be able to avoid paying for the distribution costs that they cause to be incurred. For example, a Christmas Lighting Store that is only open in November and December would require the same distribution equipment to meet its peak demand as a neighboring store that is open year round, because the facilities that are built must be built to serve the demand on the system and cannot be removed during the intervening months when they are not used, especially if they will be used again the next November & December. Yet, the Christmas Lighting Store customer would be able to avoid paying for its full portion of distribution system if there were an energy charge, since their overall energy usage over the year would not match their demand. As another example, a residential customer who has installed solar panels on her roof would still require the distribution system necessary to serve her load in the event she did not have functioning solar production, as it would be anticipated that at night or on cloudy days, the Company would need to serve the full demand. The distribution system required would be a combination of demand and customer related costs, but if the costs are recovered through an energy charge, this residential customer would avoid paying in proportion with the costs she is causing to be incurred, as the solar generation would offset energy consumption at other periods other than the period of peak demand. Thus, the residential customer with solar would avoid costs that she caused to be incurred, and other residential customers would end up subsidizing these costs. With the growth of distributed generation, the solar customer example is especially relevant in North Carolina.

Based on the above, DENC believes that the "Basic Customer" method does not adequately reflect the actual cost causation of the distribution system, nor does it result in rates that fairly recover costs on the basis of their incurrence.

6. **<u>Other Options for Allocating Distribution Costs as Customer or Demand-Related</u>:** Dominion Energy has been investigating an alternative methodology for determining customer and demand portions of distribution plant, which DENC is calling the "Average Load Duration Curve Method." This involves taking a new perspective on just what the intent of the Customer/Demand split represents in a Distribution Model FERC Account.

   Traditionally, a good deal of effort is spent in debate trying to determine the "value" of a minimum amount of FERC Account Plant that attempts to estimate the needs of a hypothetical customer with barest minimum electrical use. The current method faces further complications for accounts where present day unit costs need to be scaled back to estimated historical unit costs. Once this effort determines a Customer cost component for the FERC Account under review, this Customer component is subtracted from the total FERC Account value. This difference determines the Demand cost component for that FERC Account. Then there are further break downs based on separately derived customer class allocation factors (based on the number of customers at primary and secondary voltage levels) and demand class allocation factors (based on class peak demands or non-coincident peak demands at primary and secondary voltage levels).

   With new data collection methods and tools available to the utility, alternatives based on less theoretical frameworks are now available to help with this analysis. With its current load research software, DENC now has the ability to produce a Load Duration Curve for any defined group of customers. A Daily Load Duration Curve provides a wealth of information at a glance. The demand is graphed for every hour of the year. These curves thus produce the class maximum load, minimum load, and average load as well as the class load factor.

   DENC's distribution system has developed and refined over many years, and the design of the system continues to be evaluated to best serve the needs of the Company's customers and the usage profile of the system. DENC's distribution system thus requires much more detail and refinement than a hypothetical or theoretical system designed to carry a minimum load as many of the theoretical methods such as "Minimum System" or "Basic Customer". The system is cycled daily in real time to a maximum load and then to a minimum load. On winter days, this type of cycling may occur more than once.

   Therefore, an argument can be made that it makes the most sense to use actual field data to determine the Customer/Demand split of Distribution Plant FERC Accounts. The hourly data is available for every day of the year. This means there are a maximum peak and a minimum peak value for each day. Under the "Average Load Duration Curve Method", the actual field data for these daily maximums and minimums is used to determine the ratio between the average of the maximums and the average of the minimums. Such a method would be appropriate given that the distribution system is designed to deal with Non-Coincident Demands, and the customer component could then be treated as each customer's minimum demand, rather than the system total minimum demand. Using the average of daily minimums over the course of the year would thus more accurately capture each customer's minimum demand. Thus, the ratio of minimum demand to maximum demand represents the percent of the total FERC Account that should be designated as the customer portion. Then, as with other methods, the demand portion of the cost is the difference between customer and total. Now that each Distribution System FERC Account is split into the Customer/Demand components, then the further break down is accomplished with the Customer and Peak Demand allocation factors. A spreadsheet is attached that illustrates this straight-forward and consistent methodology.

There are a number of potential advantages to the "Average Load Duration Curve Method". This method is based on current and actual system data. The method is consistent and replicable and also reflects the realities of DENC's actual system. Based on DENC's initial investigation, it appears this method would not be subject to large fluctuations from year to year, so there would be similar or even greater stability compared to other methods. If applied by other utilities, the methodology could remain the same but would also reflect the differences in their distribution systems and load profiles. The method also simplifies the calculation of customer and demand plant, reducing the required inputs and the complications of updating and revising those as technology and system requirements change.

Aside from the method described in the preceding section, the NARUC Cost of Service manual specifically defines a method that it describes as, "Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer." (National Association of Regulatory Utility Commissioners, 1992, p. 90) This is the method primarily utilized by the Company. The other method is what in modern parlance is described as the zero-intercept method. NARUC describes this method as, "The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept." (National Association of Regulatory Utility Commissioners, 1992, p. 92) This method is only used by the Company for FERC account 368 as required in the 1973 order where it states, "the calculation of the customer component of Account 368-Transformers, shall be based upon a 0KVA Minimum intercept." (In the Matter of Application of Virginia Electric and Power Company for Authority to Increase its Electric Rates and Charges, 1973, p. 46) There are significant data availability limitations that restrict the practical use of the zero-intercept model on a broad basis to model distribution plant customer-related costs.

DENC is also currently working to refine and improve the quantification of the minimum-size, minimum-system approach, with two primary foci. First, computerized Distribution plant records can now be used to identify primary and secondary distribution plant in the field, and this information will be incorporated to determine the primary and secondary percent splits for the relevant accounts. Second, updated estimates of minimum materials costs and labor costs to install a minimum-size, minimum-system, with some consideration of today's minimum standards, are being reviewed. These efforts are in development, but when viewed from the perspective of the current case, some update to reflect technological and data availability changes since 1973 is necessary.

DENC also notes that DEC has proposed, in this proceeding, to use a "cost-per-mile of skeleton plant" method that makes use of the minimum-system concept but adopts a different approach to determining the customer component from the DENC order and appears to involve novel elements when compared with previous approved methodologies. This is an intriguing method that has a significant number of detailed engineering estimates and design parameters that requires more study by the Company prior to arriving at a conclusion as to its appropriateness for the fair recovery of distribution-related costs by DENC.

7. **<u>Company's Recommendation</u>:** The Company is prepared to continue use of the minimum-system methodology to derive the customer component of distribution-related costs. The minimum-system method is admittedly imperfect, as any methodology would be; however, it has significant historical precedent and consistency. Additionally, the basic theory underlying the minimum-system methodology is more consistent with the realities of the distribution system, as compared to methods such as the "Basic Customer" method. Furthermore, while the minimum-system method is data-intensive in terms of developing appropriate unit cost baselines, the minimum-system method has better data availability than methods such as the "Zero-Intercept" method.

   DENC is actively engaged in and undertaking an effort to modernize the specific manner in which the minimum-system concept is applied to individual accounts within the distribution model. This effort includes working to develop augmented data collection and analysis frameworks as well as reviewing and assessing other proposals such as the "cost-per-mile of skeleton plant" method being used by DEC in the current proceeding. Such evaluations and updates will further increase the accuracy of the minimum-system method, creating a better definition of customer and demand components of DENC's existing distribution system.

The Company is also encouraged by and actively investigating the "Average Load Duration Curve Method" described above and sees this as a potential way to arrive at a reasonable, fair, and consistent determination of customer and demand-related costs going forward. Not only does this method derive the relevant customer component and demand component for the distribution plant assets objectively based on empirical data analysis, but also the resulting outcome is based on a sample of tens of thousands of hours of load data from the distribution system as it exists serving customers. The data that forms the basis of this method is real to the existing distribution system, is measurable and can be recreated, and is based on actual distribution service provided to ratepayers. The sample data provided by DENC also includes multiple years with winter and summer peaks. To this point in its evaluation of the "Average Load Duration Curve Method", DENC has found that the method results in a robust and consistent analysis that reduces subjectivity and volatility in customer component computation and allocation. DENC would recommend further evaluation of this method.

8. **Appendix A-Detailed Walkthrough of FERC 364 Calculation:** The below summary was provided to Public Staff as part of the 9/11/18 meeting. A copy of the Distribution Model spreadsheet provided at the same meeting is also attached.

    Our current spreadsheet tab "A" has three sections to it. The middle section actually involves most of the input data. For Account 364, we pull in the number of total poles in North Carolina, which comes from our Fixed Asset Accounting group's Mass Item file. We also take the specific number of 35' poles in North Carolina and the total booked cost associated with the 35' poles from that Mass Item file. Note that the booked cost is based on cost at the time of installation, and thus we are using an historic, as installed, amount for those poles rather than looking at the cost of currently installing them today.

    Using the average cost of a 35' pole, which is assumed to be minimum system, and the total number of poles, we can calculate the minimum system, or customer, component of Account 364. Taking the total dollars in the account, we then calculate the demand component of Account 364 as the total amount less the customer amount.

    We also divide the distribution system between Primary level and Secondary level components. For Account 364, we use the results of a pole sampling survey to determine an approximate percentage of primary and secondary poles (both for the account in total and for the specific customer related poles) and divide the customer and the total account between primary and secondary, and then again calculate the demand component by removing the customer component from the total.

Using these numbers, we create a set of three ratios for Account 364. These are Primary to Total Account, Primary Customer to Primary Total, and Secondary Customer to Secondary Total. As we now use the UI Cost of Service Program to handle our Cost of Service, we take these ratios and allocate the Account 364 plant balance from our Plant in Service template into our 4 North Carolina Acct 364 Distribution Plant lines that appear on our Schedule 10: Primary - Customer, Primary - Demand, Secondary - Customer, and Secondary - Demand. This is done on the Dist Plant Work Sheet tab. From there, the numbers go to the UI Distribution Outputs tab, where they are organized in a way that allows us to easily paste them into the UI System.

References

In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable for Electric Service in North Carolina, Docket No. E-7, Sub 1146 (North Carolina Utilites Commission June 22, 2018).

In the Matter of Application of Virginia Electric and Power Company for Authority to Increase its Electric Rates and Charges, Docket No. E-22, Sub 141 (North Carolina Utilites Commission June 28, 1973).

National Association of Regulatory Utility Commissioners. (1992). *Electric Utility Cost Allocation Manual.* Washington, DC: National Association of Regulatory Utility Commissioners.

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UNI RICE = COS #4 000 * HAND -WH MAN RA O

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COS #8 =	$723
UNI R CE =	$556.493

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	OVERHEAD	NUMBER O CUS OMERS	UNI COS	O A COS
	CUS OMER OR ON	53.085	$62.08	$3.295.729
2	DEMAND (NE 4 - NE 2)			$ 803.40
3	O A ACCOUN 369			$ 5.099 30

	UNDERGROUND	NUMBER O CUS OMERS	UNI COS	O A COS
4	CUS OMER (AD O HOUSE)	6.426	$ 63.36	$7.6 42
5	CUS OMER (O E O HOUSE)	50.839	$ 56.49	$28.29 553
6	DEMAND (NE 7 - NE 4 & 5)			$32 95.08
7	O A ACCOUN 369 2 3 4 & 5			$68.097.776
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NC3 4~ gp	NC ACCOUN 64
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NC3 7~ gp	NC ACCOUN 67
NC3 7A~agp	NC ACCOUN 67 REGRESS ON ANA S S
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NC3 9A~agp	NC ACCOUN 69 REGRESS ON ANA S S
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REALLOCATION OF ACCOUNTS 360 (LAND) AND 361 (STRUCTURES)
DECEMBER 31, 2017

		ACCOUNT 364 POLES	ACOUNT 365 OH COND	ACCOUNT 366 CONDUITS	ACCOUNT 367 UG COND	ACCOUNT 368 TRANS	TOTAL	%	
PRIMARY-OH	CUSTOMER	168,104,088	101,933,101				270,037,189	4.1536%	V60POC
PRIMARY-OH	DEMAND	244,710,759	536,278,192				780,988,951	12.0127%	V60POD
SECONDARY-OH	CUSTOMER	152,618,449	87,159,892				239,778,341	3.6881%	V60SOC
SECONDARY-OH	DEMAND	222,168,852	625,585,815				847,754,667	13.0397%	V60SOD
UNDERGROUND	CUSTOMER			51,816,046	355,603,086		407,419,132	6.2667%	V60UC
UNDERGROUND	DEMAND			310,277,900	2,129,374,791		2,439,652,691	37.5253%	V60UD
TRANSFORMERS	CUSTOMER					117,727,399	117,727,399	1.8108%	V60TC
TRANSFORMERS	DEMAND					1,397,989,731	1,397,989,731	21.5031%	V60TD
		787,602,148	1,350,957,000	362,093,946	2,484,977,877	1,515,717,130	6,501,348,101	100.0000%	

ACCOUNT 360 - LAND AND LAND RIGHTS

		%	VA JUR
PRIMARY-OH	CUSTOMER	4.1536%	1,206,404
PRIMARY-OH	DEMAND	12.0127%	3,489,105
SECONDARY-OH	CUSTOMER	3.6881%	1,071,221
SECONDARY-OH	DEMAND	13.0397%	3,787,384
UNDERGROUND	CUSTOMER	6.2667%	1,820,164
UNDERGROUND	DEMAND	37.5253%	10,899,265
TRANSFORMERS	CUSTOMER	1.8108%	525,953
TRANSFORMERS	DEMAND	21.5031%	6,245,586
TOTAL VA-ACCT 360			67,296,011
LESS: SUBSTATION RELATED			38,250,928
ALLOCATED PORTION-360			29,045,083

ACCOUNT 361 -STRUCTURES AND IMPROVEMENTS

		%	VA JUR
PRIMARY-OH	CUSTOMER	4.1536%	96,244
PRIMARY-OH	DEMAND	12.0127%	278,351
SECONDARY-OH	CUSTOMER	3.6881%	85,459
SECONDARY-OH	DEMAND	13.0397%	302,147
UNDERGROUND	CUSTOMER	6.2667%	145,208
UNDERGROUND	DEMAND	37.5253%	869,513
TRANSFORMERS	CUSTOMER	1.8108%	41,959
TRANSFORMERS	DEMAND	21.5031%	498,256
TOTAL VA-ACCT 361			78,501,903
LESS: SUBSTATION RELATED			76,184,766
ALLOCATED PORTION-361			2,317,137
CUSTOMER			15.9192%
DEMAND			84.0808%

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December	Distribution Plant - End of Period 2017	Less Ringfenced Amounts	Distribution Plant - End of Period 2017		
FERC Acct 360.0 NC	1,892,017		1,892,017		
FERC Acct 360.0 NC Substation	976,766		976,766		
FERC Acct 360.0 Va	29,045,083		29,045,083		
FERC Acct 360.0 Va Substation	38,250,928		38,250,928	70,164,794	360
FERC Acct 361.0 NC	-		-		
FERC Acct 361.0 NC Substation	8,196,703		8,196,703		
FERC Acct 361.0 Va	2,317,137		2,317,137		
FERC Acct 361.0 Va Substation	76,184,766		76,184,766	86,698,606	361
FERC Acct 362.0 NC	84,706,202	491,877	84,214,325		
FERC Acct 362.0 Va	1,232,113,055	598,925	1,231,514,130		
FERC Acct 362.0 North Anna	-		-	1,315,728,456	362
FERC Acct 364.0 NC	77,404,210		77,404,210		
FERC Acct 364.0 Va	794,017,873	1,222,328	792,795,545	870,199,755	364
FERC Acct 365.0 NC	102,846,731		102,846,731		
FERC Acct 365.0 Va	1,374,456,401		1,374,456,401	1,477,303,132	365
FERC Acct 366.1 NC	6,779,399		6,779,399		
FERC Acct 366.1 Va	362,176,090		362,176,090	368,955,489	366
FERC Acct 367.0 NC	105,093,290		105,093,290		
FERC Acct 367.0 Va	2,486,501,703		2,486,501,703	2,591,594,993	367
FERC Acct 368.1 NC	70,544,442		70,544,442		
FERC Acct 368.1 Va	1,518,150,230		1,518,150,230		
FERC Acct 368.0 North Anna	-		-	1,588,694,672	368
FERC Acct 369.1 NC	15,099,130		15,099,130		
FERC Acct 369.1 Va	107,572,970		107,572,970		
FERC Acct 369.2-5 NC	68,097,776		68,097,776		
FERC Acct 369.2-5 Va	1,314,989,765		1,314,989,765	1,505,759,641	369
FERC Acct 370.0 NC	13,726,957		13,726,957		
FERC Acct 370.0 Va	510,358,444		510,358,444	524,085,401	370
FERC Acct 371.0 NC	713,072		713,072		
FERC Acct 371.0 NC - C1 NC	886,158		886,158		
FERC Acct 371.0 NC - C2 NC	-		-		
FERC Acct 371.0 Va	2,854,243		2,854,243		
FERC Acct 371.)Va - C1 VA	18,568,786		18,568,786		
FERC Acct 371.)Va - C2 VA	-		-	23,022,259	371
FERC Acct 373.0 NC	19,461,788		19,461,788		
FERC Acct 373.0 Va	338,110,722		338,110,722	357,572,510	373
ARO Asset - Decommissioning	-		-		
Sales and Use Tax Contra Asset - I	(18,723,156)		(18,723,156)		
ARO Asset - Non-Decommissioning	-		-		
FERC 1030 Experimental Plant	917,006		917,006		
	10,764,286,687	2,313,129	10,761,973,557		

End of Period 2017

FERC Acc. 360 - Land & Land Rights		
360 - VA-NON-PVT MILITARY	**0**	0
360 - VA - FERC	**314,712**	
360 - NC - FERC	**100,844**	
FERC Acc. 361 - Structures & Improvements		
361 - VA-NON-PVT MILITARY	**0**	0
361 - VA - FERC	**1,471,729**	
361 - NC - FERC	**1,010,567**	
FERC Acc. 362 - Station Equipment		
362 - VA-NON-PVT MILITARY	**$2,081,151**	2,081,151
362 - VA - FERC	**24,614,255**	
362 - NC - FERC	**11,411,104**	
FERC Acc. 364 - Poles, Towers & Fixtures		
364 - VA-NON-PVT MILITARY	**$3,164,042**	3,164,042
364 - VA - FERC	**3,251,683**	
364 - NC - FERC	**933,778**	
FERC Acc. 365 - O. H. Conductors & Devices		

365 - VA-NON-PVT MILITARY	$8,318,451	8,318,451
365 - VA - FERC	15,180,950	
365 - NC - FERC	4,095,633	
FERC Acc. 366 - Underground Conduit		
366 - VA-NON-PVT MILITARY	$997,382	997,382
366 - VA - FERC	$0	
366 - NC - FERC	$0	
FERC Acc. 367 - Underground Conductors & Devices		
367 - VA-NON-PVT MILITARY	$17,814,123	17,814,123
367 - VA - FERC	833,897	
367 - NC - FERC	856,753	
FERC Acc. 368 - Line Transformers		
368 - VA-NON-PVT MILITARY	$2,615,556	2,615,556
368 - VA - FERC	1,811,913	
368 - NC - FERC	187,297	
FERC Acc. 369 - Services		
369 - VA-NON-PVT MILITARY	$696,232	696,232
369 - VA - FERC	$0	
369 - NC - FERC	$0	
FERC Acc. 370 - Meters		
370 - VA-SEC 56-235.2	$72,625	72,625
370 - VA-NON-PVT MILITARY	-$467,357	-467,357
370 - VA-NON-MICRON	$11,904	11,904
370 - Va - Non - NASA	$80,485	80,485
370 - Va - Non - MS	$1,176,702	1,176,702
370 - NC - Schedule NS	$90,290	90,290
370 - VA - FERC	536,247	536,247
370 - NC - FERC	71,327	71,327
	1,572,224	
FERC Acc. 373 - Streetlights (new for 2013)		
VA-NON-PVT MILITARY	$4,146,070	4,146,070
Total Distribution Plant		

DISTRIBUTION PLANT

LAND & LAND RIGHTS		Distribution Plant Factors		
ASSIGNED FERC	415,556			
ASSIGNED VA NON	0			
SUBSTATION - DEMAND (VA	37,936,216			
O.H. PRI - CUSTOMER (VA)	1,206,404	0.041536	VA FERC 360 Allocators	V60POC
O.H. PRI - DEMAND (VA)	3,489,105	0.120127	VA FERC 360 Allocators	V60POD
O.H. SEC - CUSTOMER (VA)	1,071,221	0.036881	VA FERC 360 Allocators	V60SOC
O.H. SEC - DEMAND (VA)	3,787,384	0.130397	VA FERC 360 Allocators	V60SOD
NON-DES UG - CUSTOMER (	1,820,164	0.062667	VA FERC 360 Allocators	V60UC
NON-DES UG - DEMAND (VA	10,899,265	0.375253	VA FERC 360 Allocators	V60UD
TRANSFORMERS - CUSTOM	525,953	0.018108	VA FERC 360 Allocators	V60TC
TRANSFORMERS - DEMAND	6,245,586	0.215031	VA FERC 360 Allocators	V60TD
SUBSTATION - DEMAND (NC	875,922			
O.H. PRI - CUSTOMER (NC)	887,405	0.469026	NC FERC 360 Allocators	N60OPR
O.H. PRI - DEMAND (NC)	316,813	0.167447	NC FERC 360 Allocators	N60OSR
NON-DES UG - CUSTOMER (	584,997	0.309192	NC FERC 360 Allocators	N60NDR
NON-DES UG - DEMAND (NC	102,803	0.054335	NC FERC 360 Allocators	N60SCR
TOTAL ACCOUNT 360	**70,164,794**			
		29,045,083	VA FERC 360	
STRUCTURES & IMPROVEMENTS		1,892,017	NC FERC 360	
ASSIGNED FERC	2,482,296			
ASSIGNED VA NON	0			
SUBSTATION - DEMAND (VA	74,713,037			
O.H. PRI - CUSTOMER (VA)	96,244	0.041536	VA FERC 360 Allocators	V60POC
O.H. PRI - DEMAND (VA)	278,351	0.120127	VA FERC 360 Allocators	V60POD
O.H. SEC - CUSTOMER (VA)	85,459	0.036881	VA FERC 360 Allocators	V60SOC
O.H. SEC - DEMAND (VA)	302,147	0.130397	VA FERC 360 Allocators	V60SOD
NON-DES UG - CUSTOMER (	145,208	0.062667	VA FERC 360 Allocators	V60UC
NON-DES UG - DEMAND (VA	869,513	0.375253	VA FERC 360 Allocators	V60UD
TRANSFORMERS - CUSTOM	41,959	0.018108	VA FERC 360 Allocators	V60TC
TRANSFORMERS - DEMAND	498,256	0.215031	VA FERC 360 Allocators	V60TD
SUBSTATION - DEMAND (NC	7,186,136			
O.H. PRI - CUSTOMER (NC)	0	0.469026	NC FERC 360 Allocators	N60OPR
O.H. PRI - DEMAND (NC)	0	0.167447	NC FERC 360 Allocators	N60OSR
NON-DES UG - CUSTOMER (	0	0.309192	NC FERC 360 Allocators	N60NDR

NON-DES UG - DEMAND (NC	0	0.054335	NC FERC 360 Allocators	N60SCR		
TOTAL ACCOUNT 361	86,698,606					
		2,317,137.00	VA FERC 361			
STATION EQUIPMENT		0	NC FERC 361			
ASSIGNED FERC	36,025,359					
ASSIGNED VA NON	2,081,151	Virginia	North Carolina			
SUBSTATION - DEMAND (VA)	1,204,818,724	1,231,514,130	84,214,325			
SUBSTATION - DEMAND (NC	72,803,221	26,695,406	11,411,104			
TOTAL ACCOUNT 362	1,315,728,456	1,204,818,724	72,803,221			
STORAGE BATTERY EQUIPMENT						
ALLOCATED	0					
TOTAL ACCOUNT 363						
POLES, TOWERS, & FIXTURES		792,795,545	Virginia	77,404,210	North Carolina	364
ASSIGNED FERC	4,185,461					
ASSIGNED VA NON	3,164,042	426,115,714	Total Primary	76,470,432	Total North Carolina excl. NC FERC	
PRIMARY - CUSTOMER (VA)	170,907,711	366,679,832	Total Secondary	51,366,389	Total Primary	
PRIMARY - DEMAND (VA)	248,792,277	252,595,429	Total Primary Demand	25,104,043	Total Secondary	
SECONDARY - CUSTOMER ('	149,316,978	173,520,284	Total Primary Customer	**27,692,699**	**Primary - Customer**	
SECONDARY - DEMAND (VA)	217,362,854	**217,362,854**	**Secondary - Demand**	**23,673,690**	**Primary - Demand**	
PRIMARY - CUSTOMER (NC)	27,692,699	**149,316,978**	**Secondary - Customer**	**12,715,899**	**Secondary - Customer**	
PRIMARY - DEMAND (NC)	23,673,690	3,803,152	Primary Demand Assign	**12,388,144**	**Secondary - Demand**	
SECONDARY - CUSTOMER (I	12,715,899	2,612,573	Primary Customer Assign	933,778	Direct Assignment	
SECONDARY - DEMAND (NC	12,388,144	**248,792,277**	**Primary - Demand**			
TOTAL ACCOUNT 364	870,199,755	**170,907,711**	**Primary - Customer**			
		792,795,545		77,404,210		
OVERHEAD CONDUCT & DEV		1,374,456,401	Virginia	102,846,731	North Carolina	365
ASSIGNED FERC	19,276,583					
ASSIGNED VA NON	8,318,451	669,970,526	Total Primary	98,751,098	Total NC excl. NC FERC	
PRIMARY - CUSTOMER (VA)	103,252,429	704,485,875	Total Secondary	66,588,526	Total Primary	
PRIMARY - DEMAND (VA)	543,218,696	562,964,843	Total Primary Demand	32,162,572	Total Secondary	
SECONDARY - CUSTOMER ('	86,149,816	107,005,682	Total Primary Customer	**15,192,505**	**Primary - Customer**	
SECONDARY - DEMAND (VA)	618,336,059	**618,336,059**	**Secondary - Demand**	**51,396,021**	**Primary - Demand**	
PRIMARY - CUSTOMER (NC)	15,192,505	**86,149,816**	**Secondary - Customer**	**2,594,511**	**Secondary - Customer**	
PRIMARY - DEMAND (NC)	51,396,021	19,746,147	Primary Demand Assign	**29,568,061**	**Secondary - Demand**	

SECONDARY - CUSTOMER (I	2,594,511	3,753,254	Primary Customer Assign	4,095,633	Direct Assignment	
SECONDARY - DEMAND (NC	29,568,061	**543,218,696**	**Primary - Demand**			
TOTAL ACCOUNT 365	**1,477,303,132**	**103,252,429**	**Primary - Customer**			
		1,374,456,401		102,846,731		
UNDERGROUND CONDUIT		362,176,090	Virginia	6,779,399	North Carolina	366
ASSIGNED FERC	0					
ASSIGNED VA NON	997,382	310,348,289	Total Demand	6,779,399	Total NC excl. NC FERC	
NON-DES UG - CUSTOMER (	51,685,074	51,827,801	Total Customer	5,397,822	Total Primary	
NON-DES UG - DEMAND (VA)	309,493,634	854,656	Demand Assign	1,381,577	Total Secondary	
NON-DES UG - PRIMARY CU:	1,729,829	142,726	Customer Assign	**1,729,829**	**Primary - Customer**	
NON-DES UG - SECONDARY	301,061	**309,493,634**	**Demand**	**3,667,993**	**Primary - Demand**	
NON-DES UG - PRIMARY DEI	3,667,993	**51,685,074**	**Customer**	**301,061**	**Secondary - Customer**	
NON-DES UG - SECONDARY	1,080,516			**1,080,516**	**Secondary - Demand**	
TOTAL ACCOUNT 366	**368,955,489**			0	Direct Assignment	
		362,176,090		6,779,399		
UNDERGROUND CONDUCTORS		2,486,501,703	Virginia	105,093,290	North Carolina	367
ASSIGNED FERC	1,690,650					
ASSIGNED VA NON	17,814,123	2,130,680,549	Total Demand	104,236,537	Total NC excl. NC FERC	
NON-DES UG - CUSTOMER (	353,152,601	355,821,154	Total Customer	82,819,529	Total Primary	
NON-DES UG - DEMAND (VA)	2,114,701,082	15,979,468	Demand Assign	21,417,008	Total Secondary	
NON-DES UG - PRIMARY CU:	26,541,009	2,668,552	Customer Assign	**26,541,009**	**Primary - Customer**	
NON-DES UG - SECONDARY	4,667,002	**2,114,701,082**	**Demand**	**56,278,520**	**Primary - Demand**	
NON-DES UG - PRIMARY DEI	56,278,520	**353,152,601**	**Customer**	**4,667,002**	**Secondary - Customer**	
NON-DES UG - SECONDARY	16,750,006			**16,750,006**	**Secondary - Demand**	
TOTAL ACCOUNT 367	**2,591,594,993**			856,753	Direct Assignment	
		2,486,501,703		105,093,290		
LINE TRANSFORMERS		1,518,150,230	Virginia	70,544,442	North Carolina	368
ASSIGNED FERC	1,999,210					
ASSIGNED VA NON	2,615,556	1,400,233,983	Total Demand	70,357,145	Total NC excl. NC FERC	
ALLOCATED - CUSTOMER (V	117,572,361	117,916,247	Total Customer	61,039,370	**Demand**	
ALLOCATED - DEMAND (VA)	1,396,150,400	4,083,583	Demand Assign	9,317,775	**Customer**	
ALLOCATED - CUSTOMER (N	9,317,775	343,886	Customer Assign	187,297	Direct Assignment	
ALLOCATED - DEMAND (NC)	61,039,370	**1,396,150,400**	**Demand**			
TOTAL ACCOUNT 368	**1,588,694,672**	**117,572,361**	**Customer**			
		1,518,150,230		70,544,442		

SERVICES		1,422,562,735	Virginia	83,196,906	North Carolina	369
ASSIGNED FERC	0					
ASSIGNED VA NON	696,232	45,511,152	**Total Overhead - Dem**	83,196,906	Total NC excl. NC FERC	
O.H. SEC - CUSTOMER (VA)	61,660,142	62,061,818	**Total Overhead - Cust**	15,099,130	Total Overhead	
O.H. SEC - DEMAND (VA)	45,216,596	294,557	Demand Assign	68,097,776	Total Underground	
NON-DES UG - CUSTOMER (	720,803,105	401,675	Customer Assign	**3,295,729**	**Overhead - Customer**	
NON-DES UG - DEMAND (VA)	594,186,660	45,216,596	**Total Overhead - Dem**	**11,803,401**	**Overhead - Demand**	
O.H. SEC - CUSTOMER (NC)	3,295,729	61,660,142	**Total Overhead - Cust**	**35,902,695**	**Secondary - Customer**	
O.H. SEC - DEMAND (NC)	11,803,401	594,186,660	**Total Underground - Dem**	**32,195,081**	**Secondary - Demand**	
DES UG - CUSTOMER (NC)	35,902,695	720,803,105	**Total Underground - Cust**	0	Direct Assignment	
DES UG - DEMAND (NC)	32,195,081					
TOTAL ACCOUNT 369	**1,505,759,641**	1,422,562,735		83,196,906		

METERS			Virginia		North Carolina	370
VA SEC 56-235.2	72,625	OLD METHOD				
VA NON PRIV MILITARY	(467,357)	This method replaced with the new method on 370 reallocation tab				
VA NON-MICRON	11,904					
VA NON-NASA	80,485					
VA NON-MS	1,176,702					
NC - SCHEDULE NS	90,290					
VA FERC	536,247	510,358,444	Total Virginia	13,726,957	Total North Carolina	
NC FERC	71,327					
AMI METERS - RIDER A5 POI	0	0				
ALLOCATED - CUSTOMER (V	508,947,838	1,410,606	Direct Assignment	161,617	Direct Assignment	
ALLOCATED - CUSTOMER (N	13,565,340	**508,947,838**	**Customer**	**13,565,340**	**Customer**	
TOTAL ACCOUNT 370	524,085,401					

INSTALLATION ON CUSTOMER PREMISE	
ASSIGNED (VA)	2,854,243
FERC Acct 371.)Va - C1 VA	18,568,786
FERC Acct 371.)Va - C2 VA	0
ASSIGNED (NC)	713,072
FERC Acct 371.0 NC - C1 NC	886,158
FERC Acct 371.0 NC - C2 NC	0
TOTAL ACCOUNT 371	**23,022,259**

STREET LIGHTS & SIGNAL SYSTEMS				
ASSIGNED (VA) NEW 2013	4,146,070	333,964,652		373
OUTDOOR LIGHTING - CUST	83,058,129	83,058,129	**Outdoor Lighting**	
PUBLIC AUTHORITIES - CUS	250,906,523	**250,906,523**	**Public Authorities**	
ASSIGNED (NC)	19,461,788			
TOTAL ACCOUNT 373	357,572,510			

FERC ACCT 360 ASSIGNED FERC	415,556	360	
FERC ACCT 360 ASSIGNED VA NON	0	360	
FERC ACCT 360 SUBSTATION - DEMAND (VA)	37,936,216	360	
FERC ACCT 360 O.H. PRI - CUSTOMER (VA)	1,206,404	360	
FERC ACCT 360 O.H. PRI - DEMAND (VA)	3,489,105	360	
FERC ACCT 360 O.H. SEC - CUSTOMER (VA)	1,071,221	360	
FERC ACCT 360 O.H. SEC - DEMAND (VA)	3,787,384	360	
FERC ACCT 360 NON-DES UG - CUSTOMER (VA)	1,820,164	360	
FERC ACCT 360 NON-DES UG - DEMAND (VA)	10,899,265	360	
FERC ACCT 360 TRANSFORMERS - CUSTOMER (VA)	525,953	360	
FERC ACCT 360 TRANSFORMERS - DEMAND (VA)	6,245,586	360	
FERC ACCT 360 SUBSTATION - DEMAND (NC)	875,922	360	
FERC ACCT 360 O.H. PRI - CUSTOMER (NC)	887,405	360	
FERC ACCT 360 O.H. PRI - DEMAND (NC)	316,813	360	
FERC ACCT 360 NON-DES UG - CUSTOMER (NC)	584,997	360	
FERC ACCT 360 NON-DES UG - DEMAND (NC)	102,803	360	70,164,794
FERC ACCT 361 ASSIGNED FERC	2,482,296	361	
FERC ACCT 361 ASSIGNED VA NON	0	361	
FERC ACCT 361 SUBSTATION - DEMAND (VA)	74,713,037	361	
FERC ACCT 361 O.H. PRI - CUSTOMER (VA)	96,244	361	
FERC ACCT 361 O.H. PRI - DEMAND (VA)	278,351	361	
FERC ACCT 361 O.H. SEC - CUSTOMER (VA)	85,459	361	
FERC ACCT 361 O.H. SEC - DEMAND (VA)	302,147	361	
FERC ACCT 361 NON-DES UG - CUSTOMER (VA)	145,208	361	
FERC ACCT 361 NON-DES UG - DEMAND (VA)	869,513	361	
FERC ACCT 361 TRANSFORMERS - CUSTOMER (VA)	41,959	361	
FERC ACCT 361 TRANSFORMERS - DEMAND (VA)	498,256	361	
FERC ACCT 361 SUBSTATION - DEMAND (NC)	7,186,136	361	
FERC ACCT 361 O.H. PRI - CUSTOMER (NC)	0	361	
FERC ACCT 361 O.H. PRI - DEMAND (NC)	0	361	
FERC ACCT 361 NON-DES UG - CUSTOMER (NC)	0	361	
FERC ACCT 361 NON-DES UG - DEMAND (NC)	0	361	86,698,606
FERC ACCT 362 ASSIGNED FERC	36,025,359	362	
FERC ACCT 362 ASSIGNED VA NON	2,081,151	362	
FERC ACCT 362 SUBSTATION - DEMAND (VA)	1,204,818,724	362	
FERC ACCT 362 SUBSTATION - DEMAND (NC)	72,803,221	362	1,315,728,456
FERC ACCT 363 ALLOCATED	0	363	
FERC ACCT 364 ASSIGNED FERC	4,185,461	364	
FERC ACCT 364 ASSIGNED VA NON	3,164,042	364	
FERC ACCT 364 PRIMARY - CUSTOMER (VA)	170,907,711	364	
FERC ACCT 364 PRIMARY - DEMAND (VA)	248,792,277	364	
FERC ACCT 364 SECONDARY - CUSTOMER (VA)	149,316,978	364	
FERC ACCT 364 SECONDARY - DEMAND (VA)	217,362,854	364	
FERC ACCT 364 PRIMARY - CUSTOMER (NC)	27,692,699	364	
FERC ACCT 364 PRIMARY - DEMAND (NC)	23,673,690	364	
FERC ACCT 364 SECONDARY - CUSTOMER (NC)	12,715,899	364	
FERC ACCT 364 SECONDARY - DEMAND (NC)	12,388,144	364	870,199,755
FERC ACCT 365 ASSIGNED FERC	19,276,583	365	
FERC ACCT 365 ASSIGNED VA NON	8,318,451	365	
FERC ACCT 365 PRIMARY - CUSTOMER (VA)	103,252,429	365	
FERC ACCT 365 PRIMARY - DEMAND (VA)	543,218,696	365	
FERC ACCT 365 SECONDARY - CUSTOMER (VA)	86,149,816	365	
FERC ACCT 365 SECONDARY - DEMAND (VA)	618,336,059	365	
FERC ACCT 365 PRIMARY - CUSTOMER (NC)	15,192,505	365	
FERC ACCT 365 PRIMARY - DEMAND (NC)	51,396,021	365	
FERC ACCT 365 SECONDARY - CUSTOMER (NC)	2,594,511	365	
FERC ACCT 365 SECONDARY - DEMAND (NC)	29,568,061	365	1,477,303,132
FERC ACCT 366 ASSIGNED FERC	0	366	
FERC ACCT 366 ASSIGNED VA NON	997,382	366	
FERC ACCT 366 NON-DES UG - CUSTOMER (VA)	51,685,074	366	
FERC ACCT 366 NON-DES UG - DEMAND (VA)	309,493,634	366	

FERC ACCT 366 NON-DES UG - PRIMARY CUST (NC)	1,729,829	366	
FERC ACCT 366 NON-DES UG - SECONDARY CUST (NC)	301,061	366	
FERC ACCT 366 NON-DES UG - PRIMARY DEMAND (NC)	3,667,993	366	
FERC ACCT 366 NON-DES UG - SECONDARY DEMAND (NC)	1,080,516	366	368,955,489
FERC ACCT 367 ASSIGNED FERC	1,690,650	367	
FERC ACCT 367 ASSIGNED VA NON	17,814,123	367	
FERC ACCT 367 NON-DES UG - CUSTOMER (VA)	353,152,601	367	
FERC ACCT 367 NON-DES UG - DEMAND (VA)	2,114,701,082	367	
FERC ACCT 367 NON-DES UG - PRIMARY CUST (NC)	26,541,009	367	
FERC ACCT 367 NON-DES UG - SECONDARY CUST (NC)	4,667,002	367	
FERC ACCT 367 NON-DES UG - PRIMARY DEMAND (NC)	56,278,520	367	
FERC ACCT 367 NON-DES UG - SECONDARY DEMAND (NC)	16,750,006	367	2,591,594,993
FERC ACCT 368 ASSIGNED FERC	1,999,210	368	
FERC ACCT 368 ASSIGNED VA NON	2,615,556	368	
FERC ACCT 368 ALLOCATED - CUSTOMER (VA)	117,572,361	368	
FERC ACCT 368 ALLOCATED - DEMAND (VA)	1,396,150,400	368	
FERC ACCT 368 ALLOCATED - CUSTOMER (NC)	9,317,775	368	
FERC ACCT 368 ALLOCATED - DEMAND (NC)	61,039,370	368	1,588,694,672
FERC ACCT 369 ASSIGNED FERC	0	369	
FERC ACCT 369 ASSIGNED VA NON	696,232	369	
FERC ACCT 369 O.H. SEC - CUSTOMER (VA)	61,660,142	369	
FERC ACCT 369 O.H. SEC - DEMAND (VA)	45,216,596	369	
FERC ACCT 369 NON-DES UG - CUSTOMER (VA)	720,803,105	369	
FERC ACCT 369 NON-DES UG - DEMAND (VA)	594,186,660	369	
FERC ACCT 369 O.H. SEC - CUSTOMER (NC)	3,295,729	369	
FERC ACCT 369 O.H. SEC - DEMAND (NC)	11,803,401	369	
FERC ACCT 369 DES UG - CUSTOMER (NC)	35,902,695	369	
FERC ACCT 369 DES UG - DEMAND (NC)	32,195,081	369	1,505,759,641
FERC ACCT 370 ASSIGNED VA SEC 56-235.2	72,625	370	
FERC ACCT 370 ASSIGNED PRIV MILITARY	(467,357)	370	
FERC ACCT 370 ASSIGNED VA NON-MICRON	11,904	370	
FERC ACCT 370 ASSIGNED VA NON-NASA	80,485	370	
FERC ACCT 370 ASSIGNED VA NON-MS	1,176,702	370	
FERC ACCT 370 ASSIGNED NC SCHEDULE NS	90,290	370	
FERC ACCT 370 ASSIGNED FERC VA	536,247	370	
FERC ACCT 370 ASSIGNED FERC NC	71,327	370	
FERC ACCT 370 AMI METERS - RIDER A5 PORTION		370	
FERC ACCT 370 ALLOCATED - CUSTOMER (VA)	508,947,838	370	524,085,401
FERC ACCT 370 ALLOCATED - CUSTOMER (NC)	13,565,340	370	
FERC ACCT 371 ASSIGNED (VA)	2,854,243	371	
FERC Acct 371.)Va - C1 VA	18,568,786	371	
FERC Acct 371.)Va - C2 VA	0	371	
FERC Acct 371.0 NC	713,072	371	
FERC Acct 371.0 NC - C1 NC	886,158	371	
FERC Acct 371.0 NC - C2 NC	0	371	23,022,259
FERC ACCT 373 OUTDOOR LIGHTING - CUSTOMER	83,058,129	373	
FERC ACCT 373 PUBLIC AUTHORITIES - CUSTOMER	250,906,523	373	
FERC ACCT 373 ASSIGNED	19,461,788	373	
FERC ACCT 373 PRI MILITARY NEW 2013	4,146,070		357,572,510
	10,779,779,708		10,779,779,708
	357,572,510		

Total 370 dist model	524,085,401
Total 370 FA	524,085,401
total assigned dist	1,572,224

Distribution Model for the State of North Carolina

Average Daily Load Duration Curve Data:

Class	Cust	Demand
State of NC*	64.92%	35.08%

** Distribution customers only and FERC customers removed*

NC State Distribution Load Duration Summary			
Mininmum vs. Maximum load per day Summary			
Year	Peak Season	Zone Peak	Max/Min average ratio
2015	Winter	21,651 MW	64.74%
2016	Summer	19,538 MW	65.79%
2017	Winter	19,661 MW	64.24%
		3-year Average	64.92%

Primary/Secondary GIS Study:

Equipment	Primary	Secondary
Poles	75.86%	24.14%
Overhead	84.39%	15.61%
Underground	39.86%	60.14%

Peak Demands/Customer Allocation Factors

	NC Total	Res	SGS	LGS	6 VP	Street	Traffic
Customer-Pri							
# of Cust	84	-	70	11	3	-	-
Allocation	100.00%	0.00%	83.33%	13.10%	3.57%	0.00%	0.00%
Customer-Sec							
# of Cust	134,274	102,620	17,627	46	-	13,935	46
Allocation	100.00%	76.43%	13.13%	0.03%	0.00%	10.38%	0.03%
Customer -Total							
# of Cust	134,358	102,620	17,697	57	3	13,935	46
Allocation	100.00%	76.38%	13.17%	0.04%	0.00%	10.37%	0.03%
Demand-Pri							
Peak Demand	884,309	552,125	166,912	101,621	56,467	7,119	65
Allocation	100%	62.44%	18.87%	11.49%	6.39%	0.81%	0.01%
Demand-Sec							
Peak Demand	753,020	527,364	154,147	64,647	-	6,800	62
Allocation	100.00%	70.03%	20.47%	8.59%	0.00%	0.90%	0.01%

FERC Chart of Accounts for Distribution System Plant and Expense

360 Land and land rights.

This account shall include the cost of land and land rights used in connection with distribution operations. (See electric plant instruction 7.)

NOTE: Do not include in this account the cost of permits to erect poles, towers, etc., or to trim trees. (See account 364, Poles, Towers and Fixtures, and account 365, Overhead Conductors and Devices.)

361 Structures and improvements.

This account shall include the cost in place of structures and improvements used in connection with distribution operations. (See electric plant instruction 8.)

362 Station equipment.

This account shall include the cost installed of station equipment, including transformer banks, etc., which are used for the purpose of changing the characteristics of electricity in connection with its distribution.

ITEMS

1. Bus compartments, concrete, brick and sectional steel, including items permanently attached thereto.

2. Conduit, including concrete and iron duct runs not part of building.

3. Control equipment, including batteries, battery charging equipment, transformers, remote relay boards, and connections.

4. Conversion equipment, indoor and outdoor, frequency changers, motor generator sets, rectifiers, synchronous converters, motors, cooling equipment, and associated connections.

5. Fences.

6. Fixed and synchronous condensers, including transformers, switching equipment, blowers, motors, and connections.

7. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.

8. General station equipment, including air compressors, motors, hoists, cranes, test equipment, ventilating equipment, etc.

9. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.

10. Primary and secondary voltage connections, including bus runs and supports, insulators, potheads, lightning arresters, cable and wire runs from and to outdoor connections or to manholes and the associated regulators, reactors, resistors, surge arresters, and accessory equipment.

11. Switchboards, including meters, relays, control wiring, etc.

FERC Chart of Accounts -- https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18

12. Switching equipment, indoor and outdoor, including oil circuit breakers and operating mechanisms, truck switches, disconnect switches.

NOTE: The cost of rectifiers, series transformers, and other special station equipment devoted exclusively to street lighting service shall not be included in this account, but in account 373, Street Lighting and Signal Systems.

363 Energy Storage Equipment—Distribution

A. This account shall include the cost installed of energy storage equipment used to store energy for load managing purposes. Where energy storage equipment can perform more than one function or purpose, the cost of the equipment shall be allocated among production, transmission, and distribution plant based on the services provided by the asset and the allocation of the asset's cost through rates approved by a relevant regulatory agency. Reallocation of the cost of equipment recorded in this account shall be in accordance with Electric Plant Instruction No. 12, Transfers of Property.

B. Labor costs and power purchased to energize the equipment are includible on the first installation only. The cost of removing, relocating and resetting energy storage equipment shall not be charged to this account but to Account 582.1, Operation of Energy Storage Equipment, and Account, 592.1, Maintenance of Energy Storage Equipment, as appropriate.

C. The records supporting this account shall show, by months, the function(s) each energy storage asset supports or performs.

ITEMS

1. Batteries/Chemical
2. Compressed Air
3. Flywheels
4. Superconducting Magnetic Storage
5. Thermal

364 Poles, towers and fixtures.

This account shall include the cost installed of poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires.

ITEMS

1. Anchors, head arm, and other guys, including guy guards, guy clamps, strain insulators, pole plates, etc.
2. Brackets.
3. Crossarms and braces.
4. Excavation and backfill, including disposal of excess excavated material.
5. Extension arms.
6. Foundations.

7. Guards.

8. Insulator pins and suspension bolts.

9. Paving.

10. Permits for construction.

11. Pole steps and ladders.

12. Poles, wood, steel, concrete, or other material.

13. Racks complete with insulators.

14. Railings.

15. Reinforcing and stubbing.

16. Settings.

17. Shaving, painting, gaining, roofing, stenciling, and tagging.

18. Towers.

19. Transformer racks and platforms.

365 Overhead conductors and devices.

This account shall include the cost installed of overhead conductors and devices used for distribution purposes.

ITEMS

1. Circuit breakers.

2. Conductors, including insulated and bare wires and cables.

3. Ground wires, clamps, etc.

4. Insulators, including pin, suspension, and other types, and tie wire or clamps.

5. Lightning arresters.

6. Railroad and highway crossing guards.

7. Splices.

8. Switches.

9. Tree trimming, initial cost including the cost of permits therefor.

10. Other line devices.

NOTE: The cost of conductors used solely for street lighting or signal systems shall not be included in this account but in account 373, Street Lighting and Signal Systems.

366 Underground conduit.

This account shall include the cost installed of underground conduit and tunnels used for housing distribution cables or wires.

ITEMS

1. Conduit, concrete, brick and tile, including iron pipe, fiber pipe, Murray duct, and standpipe on pole or tower.

2. Excavation, including shoring, bracing, bridging, backfill, and disposal of excess excavated material.

3. Foundations and settings specially constructed for and not expected to outlast the apparatus for which constructed.

4. Lighting systems.

5. Manholes, concrete or brick, including iron or steel frames and covers, hatchways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.

6. Municipal inspection.

7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.

8. Permits.

9. Protection of street openings.

10. Removal and relocation of subsurface obstructions.

11. Sewer connections, including drains, traps, tide valves, check valves, etc.

12. Sumps, including pumps.

13. Ventilating equipment.

NOTE: The cost of underground conduit used solely for street lighting or signal systems shall be included in account 373, Street Lighting and Signal Systems.

367 Underground conductors and devices.

This account shall include the cost installed of underground conductors and devices used for distribution purposes.

ITEMS

1. Armored conductors, buried, including insulators, insulating materials, splices, potheads, trenching, etc.

2. Armored conductors, submarine, including insulators, insulating materials, splices in terminal chamber, potheads, etc.

3. Cables in standpipe, including pothead and connection from terminal chamber or manhole to insulators on pole.

4. Circuit breakers.

5. Fireproofing, in connection with any items listed herein.

6. Hollow-core oil-filled cable, including straight or stop joints, pressure tanks, auxiliary air tanks, feeding tanks, terminals, potheads and connections, etc.

7. Lead and fabric covered conductors, including insulators, compound-filled, oil-filled or vacuum splices, potheads, etc.

8. Lightning arresters.

9. Municipal inspection.

10. Permits.

11. Protection of street openings.

12. Racking of cables.

13. Switches.

14. Other line devices.

NOTE: The cost of underground conductors and devices used solely for street lighting or signal systems shall be included in account 373, Street Lighting and Signal Systems.

368 Line transformers.

A. This account shall include the cost installed of overhead and underground distribution line transformers and poletype and underground voltage regulators owned by the utility, for use in transforming electricity to the voltage at which it is to be used by the customer, whether actually in service or held in reserve.

B. When a transformer is permanently retired from service, the original installed cost thereof shall be credited to this account.

C. The records covering line transformers shall be so kept that the utility can furnish the number of transformers of various capacities in service and those in reserve, and the location and the use of each transformer.

ITEMS

1. Installation, labor of (first installation only).

2. Transformer cut-out boxes.

3. Transformer lightning arresters.

4. Transformers, line and network.

5. Capacitors.

6. Network protectors.

NOTE: The cost of removing and resetting line transformers shall not be charged to this account but to account 583, Overhead Line Expenses, or account 584, Underground Line Expenses (for Nonmajor utilities, account 561, Line and Station Labor, or account 562, Line and Station Supplies and Expenses), as appropriate. The cost of line transformers used solely for street lighting or signal systems shall be included in account 373, Street Lighting and Signal Systems.

369 Services.

This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the distribution box or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's outlet or wiring. Conduit used for underground service conductors shall be included herein.

ITEMS

1. Brackets.

2. Cables and wires.

3. Conduit.

4. Insulators.

5. Municipal inspection.

6. Overhead to underground, including conduit or standpipe and conductor from last splice on pole to connection with customer's wiring.

7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.

8. Permits.

9. Protection of street openings.

10. Service switch.

11. Suspension wire.

370 Meters.

A. This account shall include the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve.

B. When a meter is permanently retired from service, the installed cost included herein shall be credited to this account.

C. The records covering meters shall be so kept that the utility can furnish information as to the number of meters of various capacities in service and in reserve as well as the location of each meter owned.

ITEMS

1. Alternating current, watt-hour meters.

2. Current limiting devices.

3. Demand indicators.

4. Demand meters.

5. Direct current watt-hour meters.

6. Graphic demand meters.

7. Installation, labor of (first installation only).

8. Instrument transformers.

9. Maximum demand meters.

10. Meter badges and their attachments.

11. Meter boards and boxes.

12. Meter fittings, connections, and shelves (first set).

13. Meter switches and cut-outs.

14. Prepayment meters.

15. Protective devices.

16. Testing new meters.

NOTE A: This account shall not include meters for recording output of a generating station, substation meters, etc. It includes only those meters used to record energy delivered to customers.

NOTE B: The cost of removing and resetting meters shall be charged to account 586, Meter Expenses (for Nonmajor utilities, account 556, Meter Expenses).

371 Installations on customers' premises.

This account shall include the cost installed of equipment on the customer's side of a meter when the utility incurs such cost and when the utility retains title to and assumes full responsibility for maintenance and replacement of such property. This account shall not include leased equipment, for which see account 372, Leased Property on Customers' Premises.

ITEMS

1. Cable vaults.

2. Commercial lamp equipment.

3. Foundations and settings specially provided for equipment included herein.

4. Frequency changer sets.

5. Motor generator sets.

6. Motors.

7. Switchboard panels, high or low tension.

8. Wire and cable connections to incoming cables.

NOTE: Do not include in this account any costs incurred in connection with merchandising, jobbing, or contract work activities.

372 Leased property on customers' premises.

This account shall include the cost of electric motors, transformers, and other equipment on customers' premises (including municipal corporations), leased or loaned to customers, but not including property held for sale.

NOTE A: The cost of setting and connecting such appliances or equipment on the premises of customers and the cost of resetting or removal shall not be charged to this account but to operating expenses, account 587, Customer Installations Expenses (for Nonmajor utilities, account 567, Customer Installations Expenses).

NOTE B: Do not include in this account any costs incurred in connection with merchandising, jobbing, or contract work activities.

373 Street lighting and signal systems.

This account shall include the cost installed of equipment used wholly for public street and highway lighting or traffic, fire alarm, police, and other signal systems.

ITEMS

1. Armored conductors, buried or submarine, including insulators, insulating materials, splices, trenching, etc.

2. Automatic control equipment.

3. Conductors, overhead or underground, including lead or fabric covered, parkway cables, etc., including splices, insulators, etc.

4. Lamps, are, incandescent, or other types, including glassware, suspension fixtures, brackets, etc.

5. Municipal inspection.

6. Ornamental lamp posts.

7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.

8. Permits.

9. Posts and standards.

10. Protection of street openings.

11. Relays or time clocks.

12. Series contactors.

13. Switches.

14. Transformers, pole or underground.

580 Operation supervision and engineering.

This account shall include the cost of labor and expenses incurred in the general supervision and direction of the operation of the distribution system. Direct supervision of specific activities, such as station operation, line operation, meter department operation, etc., shall be charged to the appropriate account. (For Major utilities, see operating expense instruction 1.)

581 Load dispatching (Major only).

This account (the keeping of which is optional with the utility) shall include the cost of labor, materials used and expenses incurred in load dispatching operations pertaining to the distribution of electricity.

ITEMS

Labor:

1. Directing switching.

2. Arranging and controlling clearances for construction, maintenance, test and emergency purposes.

3. Controlling system voltages.

4. Preparing operating reports.

5. Obtaining reports on the weather and special events.

Expenses:

6. Communication service provided for system control purposes.

7. System record and report forms.

8. Meals, traveling and incidental expenses.

581.1 Line and station supplies and expenses (Nonmajor only).

582 Station expenses (Major only).

583 Overhead line expenses (Major only).

584 Underground line expenses (Major only).

Accounts 581.1 through 584 shall include, respectively, the cost of labor, materials used and expenses incurred in the operation of overhead and underground distribution lines and stations.

ITEMS

Line Labor:

1. Supervising line operation.

2. Changing line transformer taps.

3. Inspecting and testing lightning arresters, line circuit breakers, switches and grounds.

4. Inspecting and testing line transformers for the purpose of determining load, temperature or operating performance.

5. Patrolling lines.

6. Load tests and voltages surveys of feeders, circuits and line transformers.

7. Removing line transformers and voltage regulators with or without replacements.

8. Installing line transformers or voltage regulators with or without change in capacity provided that the first installation of these items is included in account 368, Line transformers.

9. Voltage surveys, either routine or upon request of customers, including voltage tests at customers' main switch.

10. Transferring loads, switching and reconnecting circuits and equipment for operation purposes.

11. Electrolysis surveys.

12. Inspecting and adjusting line testing equipment.

Line Supplies and Expenses:

13. Tool expenses.

14. Transportation expenses.

15. Meals, traveling and incidental expense.

16. Operating supplies, such as instrument charts, rubber goods, etc.

Station Labor:

1. Supervising station operation.

2. Adjusting station equipment where such adjustment primarily affects performance, such as regulating the flow of cooling water, adjusting current in fields of a machine, changing voltage of regulators or changing station transformer taps.

3. Keeping station log and records and preparing reports on station operation.

4. Inspecting, testing and calibrating station equipment for the purpose of checking its performance.

5. Operating switching and other station equipment.

6. Standing watch, guarding and patrolling station and station yard.

7. Sweeping, mopping and tidying station.

8. Care of grounds, including snow removal, cutting grass, etc.

Station Supplies and Expenses:

9. Building service expenses.

10. Operating supplies, such as lubricants, commutator brushes, water and rubber goods.

11. Station meter and instrument supplies, such as ink and charts.

12. Station record and report forms.

13. Tool expenses.

14. Transportation expenses.

15. Meals, traveling and incidental expenses.

NOTE (MAJOR ONLY): If the utility owns storage battery equipment used for supplying electricity to customers in periods of emergency, the cost of operating labor and of supplies, such as acid, gloves, hydrometers, thermometers, soda, automatic cell fillers, acid proof shoes, etc., shall be included in this account. If significant in amount, a separate subdivision shall be maintained for such expenses.

584.1 Operation of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the operation of energy storage equipment includible in Account 363, Energy Storage Equipment—Distribution, which are not specifically provided for or are readily assignable to other distribution operation expense accounts.

585 Street lighting and signal system expenses.

A. For Nonmajor utilities, this account shall include the cost of labor, materials used and expenses incurred in the operation of street lighting and signal system plant.

B. For Major utilities, this account shall include the cost of labor, materials used and expenses incurred in: (a) The operation of street lighting and signal system plant which is owned or leased by the utility; and (b) the operation and maintenance of such plant owned by customers where such work is done regularly as a part of the street lighting and signal system service.

ITEMS

Labor:

1. Supervising street lighting and signal systems operation.

2. Replacing lamps and incidental cleaning of glassware and fixtures in connection therewith.

3. Routine patrolling for lamp outages, extraneous nuisances or encroachments, etc.

4. Testing lines and equipment including voltage and current measurement.

5. Winding and inspection of time switch and other controls.

Materials and Expenses:

6. Street lamp renewals.

7. Transportation and tool expense.

8. Meals, traveling, and incidental expenses.

586 Meter expenses.

This account shall include the cost of labor, materials used and expenses incurred in the operation of customer meters and associated equipment.

ITEMS

Labor:

1. Supervising meter operation.

2. Clerical work on meter history and associated equipment record cards, test cards, and reports.

3. Disconnecting and reconnecting, removing and reinstalling, sealing and unsealing meters and other metering equipment in connection with initiating or terminating services including the cost of obtaining meter readings, if incidental to such operation.

4. Consolidating meter installations due to elimination of separate meters for different rates of service.

5. Changing or relocating meters, instrument transformers, time switches, and other metering equipment.

6. Resetting time controls, checking operation of demand meters and other metering equipment, when done as an independent operation.

7. Inspecting and adjusting meter testing equipment.

8. Inspecting and testing meters, instrument transformers, time switches, and other metering equipment on premises or in shops excluding inspecting and testing incidental to maintenance

Materials and Expenses:

9. Meter seals and miscellaneous meter supplies.

10. Transportation expenses.

11. Meals, traveling, and incidental expenses.

12. Tool expenses.

NOTE: The cost of the first setting and testing of a meter is chargeable to utility plant account 370, Meters.

587 Customer installations expenses.

This account shall include the cost of labor, materials used and expenses incurred in work on customer installations in inspecting premises and in rendering services to customers of the nature of those indicated by the list of items hereunder.

ITEMS

Labor:

1. Supervising customer installations work.

2. Inspecting premises, including check of wiring for code compliance.

3. Investigating, locating, and clearing grounds on customers' wiring.

4. Investigating service complaints, including load tests of motors and lighting and power circuits on customers' premises; field investigations of complaints on bills or of voltage.

5. Installing, removing, renewing, and changing lamps and fuses.

6. Radio, television and similar interference work including erection of new aerials on customers' premises and patrolling of lines, testing of lightning arresters, inspection of pole hardware, etc., and examination on or off premises of customers' appliances, wiring, or equipment to locate cause of interference.

7. Installing, connecting, reinstalling, or removing leased property on customers' premises.

8. Testing, adjusting, and repairing customers' fixtures and appliances in shop or on premises.

9. Cost of changing customers' equipment due to changes in service characteristics.

10. Investigation of current diversion including setting and removal of check meters and securing special readings thereon; special calls by employees in connection with discovery and settlement of current diversion; changes in customer wiring and any other labor cost identifiable as caused by current diversion.

Materials and Expenses:

11. Lamp and fuse renewals.

12. Materials used in servicing customers' fixtures, appliances and equipment.

13. Power, light, heat, telephone, and other expenses of appliance repair department.

14. Tool expense.

15. Transportation expense, including pickup and delivery charges.

16. Meals, traveling and incidental expenses.

17. Rewards paid for discovery of current diversion.

NOTE A: Amounts billed customers for any work, the cost of which is charged to this account, shall be credited to this account. Any excess over costs resulting therefrom shall be transferred to account 451, Miscellaneous Service Revenues.

NOTE B: Do not include in this account expenses incurred in connection with merchandising, jobbing and contract work.

588 Miscellaneous distribution expenses.

This account shall include the cost of labor, materials used and expenses incurred in distribution system operation not provided for elsewhere.

ITEMS

Labor:

1. General records of physical characteristics of lines and substations, such as capacities, etc.

2. Ground resistance records.

3. Joint pole maps and records.

4. Distribution system voltage and load records.

5. Preparing maps and prints.

6. Service interruption and trouble records.

7. General clerical and stenographic work except that chargeable to account 586, Meter expenses.

Expenses:

8. Operating records covering poles, transformers, manholes, cables, and other distribution facilities. Exclude meter records chargeable to account 586. Meter Expenses and station records chargeable to account 582, Station Expenses (For Nonmajor utilities, account 581.1, Line and Station Expenses), and stores records (For Nonmajor utilities, station records) chargeable to account 163, Stores Expense Undistributed (For Nonmajor utilities, account 581.1, Line and Station Expenses).

9. Janitor work at distribution office buildings including snow removal, cutting grass, etc.

Materials and Expenses:

10. Communication service.

11. Building service expenses.

12. Miscellaneous office supplies and expenses, printing, and stationery, maps and records and first-aid supplies.

13. Research, development, and demonstration expenses (Major only).

589 Rents.

This account shall include rents of property of others used, occupied, or operated in connection with the distribution system, including payments to the United States and others for the use and occupancy of public lands and reservations for distribution line rights of way. (See operating expense instruction 3.)

590 Maintenance supervision and engineering (Major only).

This account shall include the cost of labor and expenses incurred in the general supervision and direction of maintenance of the distribution system. Direct field supervision of specific jobs shall be charged to the appropriate maintenance account. (See operating expense instruction 1.)

591 Maintenance of structures (Major only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of structures, the book cost of which is includible in account 361, Structures and Improvements. (See operating expense instruction 2.)

592 Maintenance of station equipment (Major only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in account 362, Station Equipment, and account 363, Storage Battery Equipment. (See operating expense instruction 2.)

592.1 Maintenance of Structures and Equipment (Nonmajor Only)

This account shall include the cost of labor, materials used and expenses incurred in maintenance of structures, the book cost of which is includible in account 361, Structures and Improvements, and account 362, Station Equipment. (See operating expense instruction 2.)

593 Maintenance of overhead lines (Major only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is includible in account 364, Poles, Towers and Fixtures, account 365, Overhead Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on poles, towers, and fixtures:

a. Installing additional clamps or removing clamps or strain insulators on guys in place.

b. Moving line or guy pole in relocation of pole or section of line.

c. Painting poles, towers, crossarms, or pole extensions.

d. Readjusting and changing position of guys or braces.

e. Realigning and straightening poles, crossarms, braces, pins, racks, brackets, and other pole fixtures.

f. Reconditioning reclaimed pole fixtures.

g. Relocating crossarms, racks, brackets, and other fixtures on poles.

h. Repairing pole supported platform.

i. Repairs by others to jointly owned poles.

j. Shaving, cutting rot, or treating poles or crossarms in use or salvaged for reuse.

k. Stubbing poles already in service.

l. Supporting conductors, transformers, and other fixtures and transferring them to new poles during pole replacements.

m. Maintaining pole signs, stencils, tags, etc.

2. Work of the following character on overhead conductors and devices:

a. Overhauling and repairing line cutouts, line switches, line breakers, and capacitor installations.

b. Cleaning insulators and bushings.

c. Refusing line cutouts.

d. Repairing line oil circuit breakers and associated relays and control wiring.

e. Repairing grounds.

f. Resagging, retying, or rearranging position or spacing of conductors.

g. Standing by phones, going to calls, cutting faulty lines clear, or similar activities at times of emergency.

h. Sampling, testing, changing, purifying, and replenishing insulating oil.

i. Transferring loads, switching, and reconnecting circuits and equipment for maintenance purposes.

j. Repairing line testing equipment.

k. Trimming trees and clearing brush.

l. Chemical treatment of right of way area when occurring subsequent to construction of line.

3. Work of the following character on overhead services:

a. Moving position of service either on pole or on customers' premises.

b. Pulling slack in service wire.

c. Retying service wire.

d. Refastening or tightening service bracket.

594 Maintenance of underground lines (Major only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is includible in account 366, Underground Conduit, account 367, Underground Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on underground conduit:

a. Cleaning ducts, manholes, and sewer connections.

b. Moving or changing position of conduit or pipe.

c. Minor alterations of handholes, manholes, or vaults.

d. Refastening, repairing, or moving racks, ladders, or hangers in manholes or vaults.

e. Plugging and shelving ducts.

f. Repairs to sewers, drains, walls, and floors, rings and covers.

2. Work of the following character on underground conductors and devices:

a. Repairing circuit breakers, switches, cutouts, network protectors, and associated relays and control wiring.

b. Repairing grounds.

c. Retraining and reconnecting cables in manholes including transfer of cables from one duct to another.

d. Repairing conductors and splices.

e. Repairing or moving junction boxes and potheads.

f. Refireproofing cables and repairing supports.

g. Repairing electrolysis preventive devices for cables.

h. Repairing cable bonding systems.

i. Sampling, testing, changing, purifying and replenishing insulating oil.

j. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes.

k. Repairing line testing equipment.

l. Repairing oil or gas equipment in high voltage cable systems and replacement of oil or gas.

3. Work of the following character on underground services:

a. Cleaning ducts.

b. Repairing any underground service plant.

594.1 Maintenance of lines (Nonmajor only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of distribution line facilities, the book cost of which is includible in account 364, Poles, Towers and Fixtures, account 365, Overhead Conductors and Devices, account 366, Underground Conduit, account 367, Underground Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on poles, towers, and fixtures:

a. Installing additional clamps or removing clamps or strain insulators on guys in place.

b. Moving line or guy pole in relocation of pole or section of line.

c. Painting poles, towers, crossarms, or pole extensions.

d. Readjusting and changing position of guys or braces.

e. Realigning and straightening poles, crossarms, braces, pins, racks, brackets, and other pole fixtures.

f. Reconditioning reclaimed pole fixtures.

g. Relocating crossarms, racks, brackets, and other fixtures on pole.

h. Repairing pole supported platform.

i. Repairs by others to jointly owned poles.

j. Shaving, cutting rot, or treating poles or crossarms in use or salvage for reuse.

k. Stubbing poles already in service.

l. Supporting conductors, transformers, and other fixtures and transferring them to new poles during pole replacement.

m. Maintaining pole signs, stencils, tags, etc.

2. Work of the following character on overhead conductors and devices:

a. Overhauling and repairing line cutouts, line switches, line breakers, and capacitor installations.

b. Cleaning insulators and bushings.

c. Refusing line cutouts.

d. Repairing line oil circuit breakers and associated relays and control wiring.

e. Repairing grounds.

f. Resagging, retying, or rearranging position or spacing of conductors.

g. Standing by phones, going to calls, cutting faulting lines clear, or similar activities at times of emergencies.

h. Sampling, testing, changing, purifying, and replenishing insulating oil.

i. Transferring loads, switching, and reconnecting circuits and equipment for maintenance purposes.

j. Repairing line testing equipment.

k. Trimming trees and clearing brush.

l. Chemical treatment of right of way area when occurring subsequent to construction of line.

3. Work of the following character on underground conduit:

a. Cleaning ducts, manholes, and sewer connections.

b. Moving or changing position of conduit or pipe.

c. Minor alterations of handholes, manholes, or vaults.

d. Refastening, repairing or moving racks, ladders, or hangers in manholes or vaults.

e. Plugging and shelving ducts.

f. Repairs to sewers, drains, walls and floors, rings and covers.

4. Work of the following character on underground conductors and devices:

a. Repairing circuit breakers, switches, cutouts, network protectors, and associated relays and control wiring.

b. Repairing grounds.

c. Retraining and reconnecting cables in manhole including transfer of cables from one duct to another.

d. Repairing conductors and splices.

e. Repairing or moving junction boxes and potheads.

f. Refireproofing cables and repairing supports.

g. Repairing electrolysis preventive devices for cables.

h. Repairing cable bonding systems.

i. Sampling, testing, changing, purifying and replenishing insulating oil.

j. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes.

k. Repairing line testing equipment.

l. Repairing oil or gas equipment in high voltage cable system and replacement of oil or gas.

5. Work of the following character on services:

a. Moving position of service either on pole or on customers' premises.

b. Pulling slack in service wire.

c. Retying service wire.

d. Refastening or tightening service bracket.

e. Cleaning ducts.

595 Maintenance of line transformers.

This account shall include the cost of labor, materials used and expenses incurred in maintenance of distribution line transformers, the book cost of which is includible in account 368, Line Transformers. (See operating expense instruction 2.)

596 Maintenance of street lighting and signal systems.

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in account 373, Street Lighting and Signal Systems. (See operating expense instruction 2.)

597 Maintenance of meters.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of meters and meter testing equipment, the book cost of which is includible in account 370, Meters, and account 395, Laboratory Equipment, respectively. (See operating expense instruction 2.)

598 Maintenance of miscellaneous distribution plant.

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in accounts 371, Installations on Customers' Premises, and 372, Leased Property on Customers' Premises, and any other plant the maintenance of which is assignable to the distribution function and is not provided for elsewhere. (See operating expense instruction 2.)

ITEMS

a. Work of similar nature to that listed in other distribution maintenance accounts.

b. Maintenance of office furniture and equipment used by distribution system department.

APPENDIX 3

Summary of Orders and Documents Regarding Cost of Service, Minimum System, and Basic Customer Charges

Docket No.	Order Dated		Notes
E-7, Sub 120	February 12, 1971		No notable items on COSS, MSM, or BCCs
E-7, Sub 145	June 21, 1973	1	Noted an order requiring Duke to file a report on Cost of Service Study, dated September 28, 1970 in E-7 Sub 120.
		2	FOF 22 cites minimum intercept method is more correct & stable than minimum size method.
		3	Commission's E&C for "Rates" recognizes that the minimum customer cost is not covered by the charge for 100 kWh. However, Commission is reluctant to move it too much toward that goal (principle of gradualism). Commission approved using 80 kWh as the basis for the customer charge.
		4	Requirement to file an annual COSS. Said study to include - demand data, size of distribution plant used to compute customer-related components of distribution system that will comply with NESC, cost of the sizes and regression associated with the minimum intercept method, and any changes noted from past COSSs.
E-7, Sub 161 & 173	October 3, 1975	1	Commission concluded that rate design should reflect the cost of electric service to customers, conserve energy resources, and promote economic efficiencies. (E&C for FOF 18)
		2	Customer costs including billing costs, meters, service drop, and part of the distribution plant. Duke recovers these through a minimum bill and in the early block of energy rates. (E&C for FOF 18)
		3	Introduces the basic facilities charge. Its set regardless of energy use to recover customer costs that are fixed. (E&C for FOF 18)
		4	TOU and peak pricing to be reviewed in Docket E-100, Sub 21 beginning in Dec 1975. Demand growth in system peaks is happening.
S:/Floyd/E-7 Sub 145 Fully Distr Cost of Svc 1970 AND S:/Floyd/E-7 Sub 145 App to Author Adjustment of Rates 11.16.72			Actual cost of service document dated December 1970 - Describes minimum size and minimum intercept methods and "skeleton" system.
E-2, Sub 193	February 26, 1971	1	FOF 3 notes that CP&L has started a 2 year COSS per October 2, 1970 order (Docket ???)
E-2, Sub 229	January 6, 1975	1	Rate design issues too numerous to discuss individually. (Summary item #5 or Order)
		2	Commission denies increases in lower tiers of rates for residential and small and medium general service rates. These customers are not driving the need for increased revenues.
E-2, Sub 264	February 20, 1976	1	Most customer-related costs will be recovered in the a separate customer charge. (FOF 16)
		2	COSS should be used as a guide in the setting of rates but not used as the sole determining factor in rate design. (p.110 Order)
		3	Discussion in this order is similar to E-7 Sub 161 & 173 above.
E-2, Sub 297	September 9, 1977	1	Residential rate design proposed by CP&L is approved, except for the BCC, which should be decreased. (FOF 24)
	June 29, 1977		
E-2, Sub 526	August 27, 1987	1	SWPA COSS method and use of the minimum system method is appropriate. (FOF 8)
		2	CP&L requested approval to discontinue using minimum system method. Request was denied. (E&C for FOF 8)
		3	MSM allocates more distribution plant to residential customers and less to industrial customers and is conceptually sound even if the result of the MSM is not fully reflected in the BFC. Also, the MSM will modify the impact of SWPA on the industrial class.
E-2, Sub 537 & 333	July 5, 1988	1	Same language about COSS and MSM as the Sub 526 order above.
		2	No change made to the BCC. (App. A of Order)
E-22, Sub 141	June 28, 1973	1	Prescribes the calculation of the MSM.